QUADRENNIAL ENERGY REVIEW

TRANSFORMING THE NATION'S ELECTRICITY SYSTEM: THE SECOND INSTALLMENT OF THE QER

January 2017

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Preface

In June 2013, in response to a 2011 recommendation by the President's Council of Advisors on Science and Technology, President Obama initiated a quadrennial cycle of energy reviews to provide a multi-year roadmap for U.S. energy policy. In a Presidential Memorandum released on January 9, 2014 (see page iii for full text), President Obama directed his Administration to conduct a Quadrennial Energy Review (QER),[1] and announced the formation of a White House Task Force—co-chaired by the Director of the Office of Science and Technology Policy and the Special Assistant to the President for Energy and Climate Change from the Domestic Policy Council and comprising 22 Federal agencies with equities in energy—to develop the QER. The Task Force is directed to deliver a report to the President that does the following:

- Provides an integrated view of, and recommendations for, Federal energy policy in the context of economic, environmental, occupational, security, and health and safety priorities, with attention in the first report given to the challenges facing the Nation's energy infrastructures
- Reviews the adequacy of existing executive and legislative actions and recommends additional executive and legislative actions as appropriate
- Assesses and recommends priorities for research, development, and demonstration programs to support key energy innovation goals
- Identifies analytical tools and data needed to support further policy development and implementation.

The President further directed the Department of Energy (DOE) to provide analytical support for the QER and to help manage the interagency process through a secretariat at DOE. This is consistent with DOE's missions and statutory responsibilities. DOE has undertaken periodic reviews and analyses of the energy sector (including in the "National Energy Strategy" of 1991 and the "Comprehensive Energy Strategy" of 1998) and contributed to the work of the National Energy Policy Development Group led by the Vice President in 2001, but that national energy policy report was published nearly 16 years ago, and the U.S. energy system has changed very significantly over that period. The Presidential Memorandum on the QER acknowledges that such a review is overdue and recognizes the high value of the White House as the convener of such an effort. It also reinforces the equities that multiple agencies have in Federal energy policy.

As directed by the President, the QER is envisioned as a focused, actionable document designed to provide policymakers, industry, investors, and other stakeholders with unbiased data and analysis on energy challenges, needs, requirements, and barriers that will inform a range of policy options, including legislation. Each installment of the QER will analyze and make recommendations for a key component of the energy value chain.

On February 4, 2016, the Task Force convened a public meeting to introduce the topic of the second installment of the QER (QER 1.2), an integrated study of the U.S. electricity system from generation through end use.[2] This installment analyzes trends and issues confronting the Nation's electricity sector out to 2040, examining the entire electricity supply chain from generation to end use, and within the context of three overarching national goals to: (1) enhance economic competitiveness; (2) promote environmental responsibility; and (3) provide for the Nation's security.

[1] The White House, "Presidential Memorandum -- Establishing a Quadrennial Energy Review," The White House, Office of the Press Secretary, January 9, 2014, https://obamawhitehouse.archives.gov/the-press-office/2014/01/09/presidential-memorandum-establishing-quadrennial-energy-review.

[2] Quadrennial Energy Review; Notice of Public Meeting, 81 Fed. Reg. 4025 (January 25, 2016), https://www.federalregister.gov/documents/2016/01/25/2016-01372/quadrennial-energy-review-notice-of-public-meeting?utm_content=&utm_medium=email&utm_name=&utm_source=govdelivery&utm_term=.

Presidential Memorandum

The White House
January 09, 2014

Presidential Memorandum -- Establishing a Quadrennial Energy Review
MEMORANDUM FOR THE HEADS OF EXECUTIVE DEPARTMENTS AND AGENCIES

Affordable, clean, and secure energy and energy services are essential for improving U.S. economic productivity, enhancing our quality of life, protecting our environment, and ensuring our Nation's security. Achieving these goals requires a comprehensive and integrated energy strategy resulting from interagency dialogue and active engagement of external stakeholders. To help the Federal Government better meet this responsibility, I am directing the undertaking of a Quadrennial Energy Review.

The initial focus for the Quadrennial Energy Review will be our Nation's infrastructure for transporting, transmitting, and delivering energy. Our current infrastructure is increasingly challenged by transformations in energy supply, markets, and patterns of end use; issues of aging and capacity; impacts of climate change; and cyber and physical threats. Any vulnerability in this infrastructure may be exacerbated by the increasing interdependencies of energy systems with water, telecommunications, transportation, and emergency response systems. The first Quadrennial Energy Review Report will serve as a roadmap to help address these challenges.

The Department of Energy has a broad role in energy policy development and the largest role in implementing the Federal Government's energy research and development portfolio. Many other executive departments and agencies also play key roles in developing and implementing policies governing energy resources and consumption, as well as associated environmental impacts. In addition, non-Federal actors are crucial contributors to energy policies. Because most energy and related infrastructure is owned by private entities, investment by and engagement of the private sector is necessary to develop and implement effective policies. State and local policies; the views of nongovernmental, environmental, faith-based, labor, and other social organizations; and contributions from the academic and non-profit sectors are also critical to the development and implementation of effective energy policies.

An interagency Quadrennial Energy Review Task Force, which includes members from all relevant executive departments and agencies (agencies), will develop an integrated review of energy policy that integrates all of these perspectives. It will build on the foundation provided in my Administration's Blueprint for a Secure Energy Future of March 30, 2011, and Climate Action Plan released on June 25, 2013. The Task Force will offer recommendations on what additional actions it believes would be appropriate. These may include recommendations on additional executive or legislative actions to address the energy challenges and opportunities facing the Nation.

Therefore, by the authority vested in me as President by the Constitution and the laws of the United States of America, I hereby direct the following:

Section 1. Establishing the Quadrennial Energy Review Task Force.

(a) There is established the Quadrennial Energy Review Task Force (Task Force), to be co-chaired by the Director of the Office of Science and Technology Policy and the Director of the Domestic Policy Council, which shall include the heads of each of the following, or their designated representatives:

(i) the Department of State;

(ii) the Department of the Treasury;

(iii) the Department of Defense;

(iv) the Department of the Interior;

(v) the Department of Agriculture;

(vi) the Department of Commerce;

(vii) the Department of Labor;

(viii) the Department of Health and Human Services;

(ix) the Department of Housing and Urban Development;

(x) the Department of Transportation;

(xi) the Department of Energy;

(xii) the Department of Veterans Affairs;

(xiii) the Department of Homeland Security;

(xiv) the Office of Management and Budget;

(xv) the National Economic Council;

(xvi) the National Security Staff;

(xvii) the Council on Environmental Quality;

(xviii) the Council of Economic Advisers;

(xix) the Environmental Protection Agency;

(xx) the Small Business Administration;

(xxi) the Army Corps of Engineers;

(xxii) the National Science Foundation; and

(xxiii) such agencies and offices as the President may designate.

(b) The Co-Chairs may invite independent regulatory agencies with energy-related responsibilities, including the Federal Energy Regulatory Commission and the Nuclear Regulatory Commission, to participate in the Task Force, as determined to be appropriate by those agencies.

(c) The Co-Chairs shall regularly convene and preside at meetings of the Task Force and shall determine its agenda. Under the direction of the Co-Chairs, the Task Force shall:

(i) gather ideas and advice from State and local governments, tribes, large and small businesses, universities, national laboratories, nongovernmental and labor organizations, consumers, and other stakeholders and interested parties; and

(ii) coordinate the efforts of agencies and offices related to the development of the Quadrennial Energy Review Report, as described in sections 1 and 2 of this memorandum.

(d) The Secretary of Energy shall provide support to the Task Force, including support for coordination activities related to the preparation of the Quadrennial Energy Review Report, policy analysis and modeling, and stakeholder engagement.

(e) The Task Force shall submit a Quadrennial Energy Review Report to the President every 4 years beginning with a report delivered by January 31, 2015. Intermediate reports and other material may be prepared by the Task Force as required by the President.

Sec. 2. The Quadrennial Energy Review Report.

The Task Force shall establish integrated guidance to strengthen U.S. energy policy. Building on the Blueprint for a Secure Energy Future and the Climate Action Plan, and taking into consideration applicable laws and regulations, the Task Force shall prepare a Quadrennial Energy Review Report that:

(a) provides an integrated view of, and recommendations for, Federal energy policy in the context of economic, environmental, occupational, security, and health and safety priorities, with attention in the first report given to the challenges facing the Nation's energy infrastructures;

(b) reviews the adequacy, with respect to energy policy, of existing executive and legislative actions, and recommends additional executive and legislative actions as appropriate;

(c) assesses and recommends priorities for research, development, and demonstration programs to support key energy-innovation goals; and

(d) identifies analytical tools and data needed to support further policy development and implementation.

Sec. 3. Outreach.

In order to gather information and recommendations and to provide for a transparent process in developing the Quadrennial Energy Review Report, the Task Force shall engage with State and local governments, tribes, large and small businesses, universities, national laboratories, nongovernmental and labor organizations, and other stakeholders and interested parties. The Task Force shall develop an integrated outreach strategy that relies on both traditional meetings and the use of information technology.

Sec. 4. General Provisions.

(a) This memorandum shall be implemented consistent with applicable law and subject to the availability of appropriations.

(b) Nothing in this memorandum shall be construed to impair or otherwise affect:

(i) the authority granted by law to any agency, or the head thereof; or

(ii) the functions of the Director of the Office of Management and Budget relating to budgetary, administrative, or legislative proposals.

(c) Nothing in this memorandum shall be construed to require the disclosure of confidential business information or trade secrets, classified information, law enforcement sensitive information, or other information that must be protected in the interest of national security or public safety.

(d) This memorandum is not intended to, and does not, create any right or benefit, substantive or procedural, enforceable at law or in equity by any party against the United States, its departments, agencies, or entities, its officers, employees, or agents, or any other person.

(e) The Director of the Office of Science and Technology Policy is authorized and directed to publish this memorandum in the Federal Register.

BARACK OBAMA

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Summary

TRANSFORMING THE NATION'S ELECTRICITY SYSTEM: THE SECOND INSTALLMENT OF THE QUADRENNIAL ENERGY REVIEW

Summary for Policymakers

The second installment of the Quadrennial Energy Review (QER 1.2) focuses on the electricity system and its role as the enabler for accomplishing three key national goals: enhancing economic competitiveness, promoting environmental responsibility, and providing for the Nation's security. As a critical and essential national asset, it is a strategic imperative to protect and enhance the value of the electricity system through modernization and transformation. Reliable and affordable electricity provides essential energy services for consumers, businesses, and national defense.

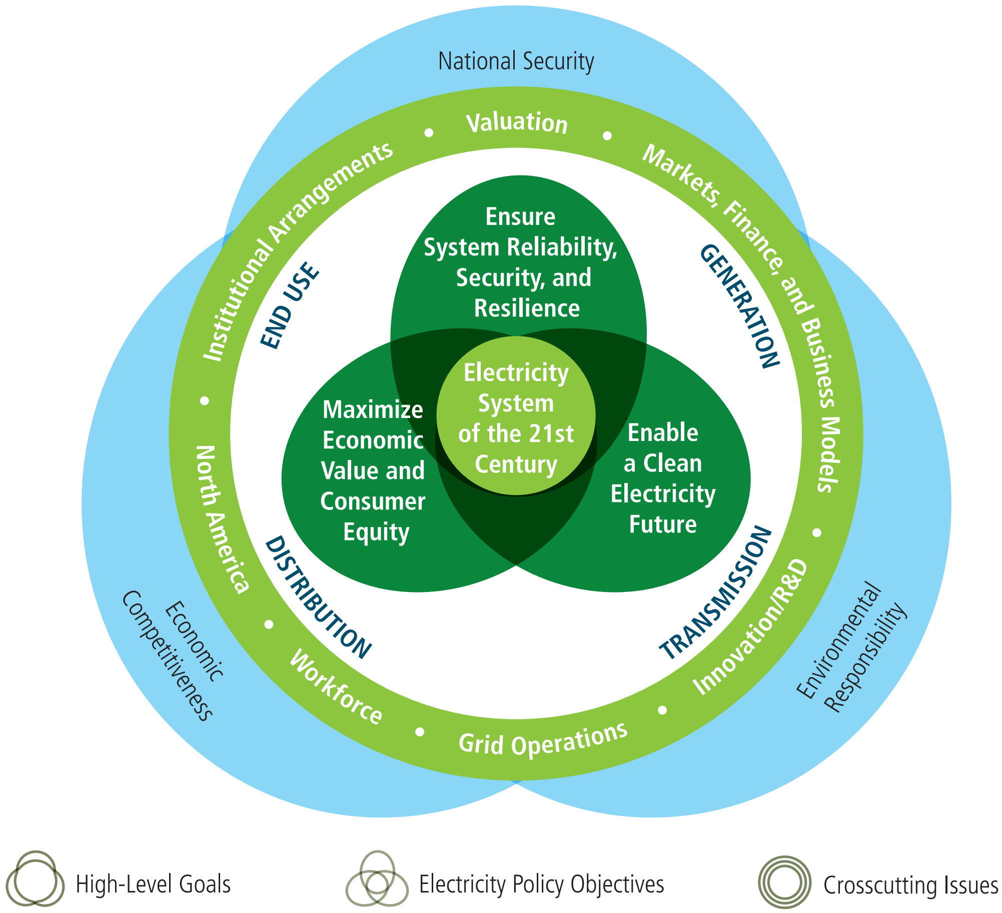
The electricity system the United States has today was developed over more than a century and includes thousands of generating plants, hundreds of thousands of miles of transmission lines, distribution systems serving hundreds of millions of customers, a growing number of distributed energy resources (DER), and billions of end-use devices and appliances. These elements are connected together to form a complex system of systems. The electricity sector is, however, confronting a complex set of changes and challenges, including aging infrastructure; a changing generation mix; growing penetration of variable generation; low and, in some cases, negative load growth; climate change; increased physical and cybersecurity risks; and, in some regions, widespread adoption of DER. How these changes are managed is critical and could fundamentally transform the electricity system's structure, operations, customer base, and jurisdictional framework.

QER 1.2 analyzes trends and issues confronting the Nation's electricity sector out to 2040, examining the entire electricity supply chain from generation to end use; it does this within the context of three overarching national goals to (1) enhance economic competitiveness, (2) promote environmental responsibility, and (3) provide for the Nation's security. The report builds on analysis and recommendations in the first installment of the QER (QER 1.1) for improving energy transmission, distribution, and storage infrastructures, and provides recommendations that must be implemented to optimize and modernize the electricity sector.

Scope and Structure of QER 1.2

In 2013, President Obama directed the Administration to conduct an interagency QER in order to "establish integrated guidance to strengthen U.S. energy policy." QER 1.1, published in April 2015, focused "on infrastructure challenges, and identified the threats, risks, and opportunities for U.S. energy and climate

Figure S-1. Organization/Areas of Focus in QER 1.2



A comprehensive set of interactions and overlapping objectives and goals must be analyzed to inform policies that will enable the electricity sector of the 21st century. Analysis in QER 1.2 is organized around a set of national goals, integrated objectives, and crosscutting issues.

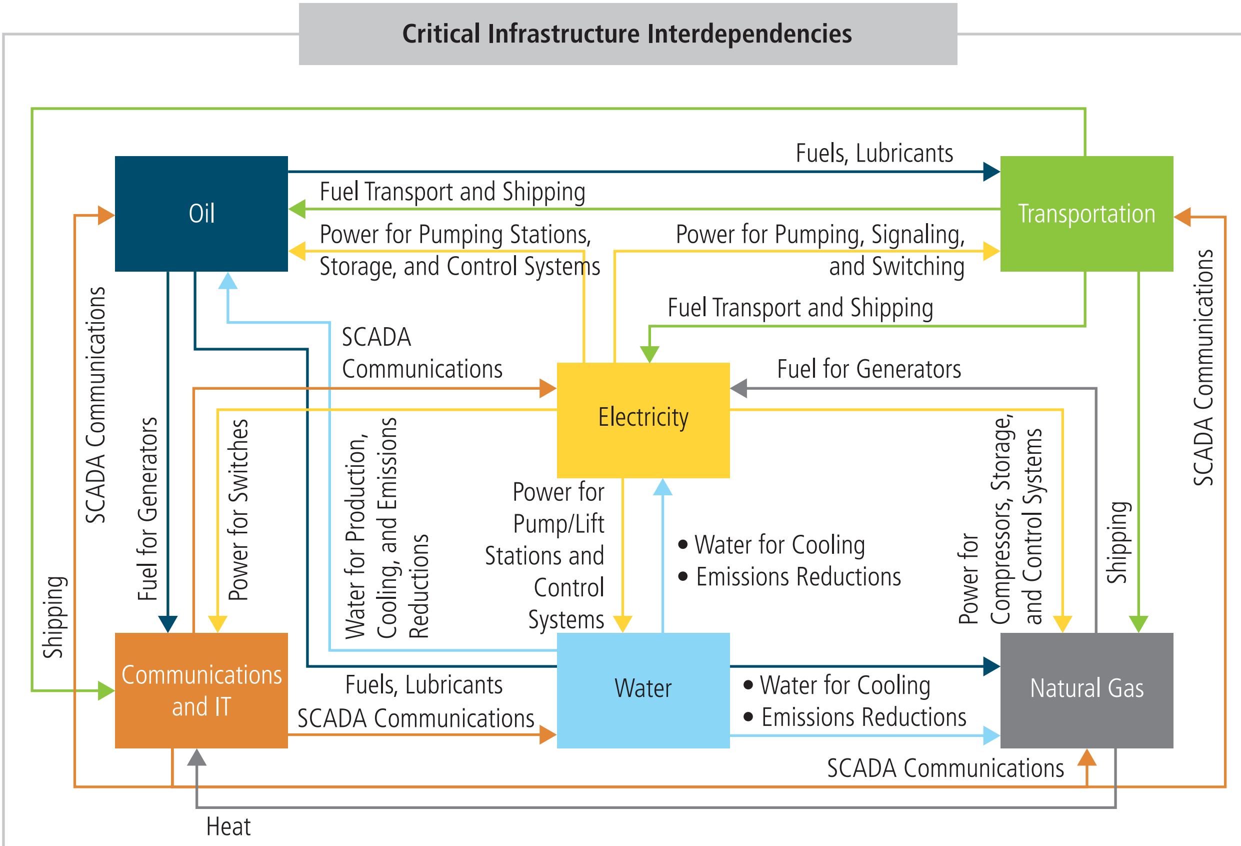
security, enabling the Federal Government to translate policy goals into a set of analytically based, clearly articulated, sequenced and integrated actions, and proposed investments."

QER 1.2 analyzes trends and issues confronting the Nation's electricity sector (Figure S-1). It builds on analysis and recommendations in QER 1.1, which included electricity as part of an examination of energy transmission, distribution, and storage infrastructures. The scope of QER 1.2 includes generation, transmission, distribution, and end-use applications in the electricity sector. It does not explore other energy-related sectors, except where they directly affect the electricity system, such as the critical role of natural gas supply in generation and reliability.

This summary follows the organization of the main report, starting with an introduction to electricity generation issues and the changing context, corresponding to the first chapter of the main report. The summary then highlights key findings based on deep analysis from several sections on the integrated objectives of the report.

This summary also includes brief summaries of select recommendations to modernize and transform the electricity sector. Specific descriptions of and rationale for the 76 QER 1.2 recommendations can be found in Chapter VII (*A 21st-Century Electricity System: Conclusions and Recommendations*). QER 1.2 also includes an appendix with an overview of the electricity system (Appendix, *Electricity System Overview*).

Figure S-2. Critical Infrastructure Interdependencies



Key critical infrastructure interdependencies represent the core underlying framework that supports the American economy and society. The financial services sector (not pictured) is also a critical infrastructure with interdependencies across other major sectors supporting the U.S. economy.

Acronyms: supervisory control and data acquisition (SCADA).

The Electricity Sector and National Goals

While respecting state, regional, and tribal prerogatives, QER 1.2 supports development of a consistent Federal strategy that accounts for the complex electricity sector context. The analysis conducted for QER 1.2 identifies three major integrated objectives that address the needs and challenges to enable the electricity sector of the 21st century. These objectives—discussed in detail in several QER 1.2 chapters—include (1) maximizing economic value and consumer equity; (2) building a clean electricity future; and (3) ensuring electricity system reliability, security, and resilience. In addition to these objectives, QER 1.2 also explores several crosscutting issues and includes in-depth chapters on two of these issues: workforce issues and North American electricity system integration.

The Nation's critical infrastructures depend on electricity. Electricity is at the center of key infrastructure systems that support these sectors, including transportation, oil and gas production, water, communications and information, and finance. These electricity-dependent critical infrastructures represent core lifeline networks that support the American economy and society. These critical networks are increasingly converging, sharing resources and synergistic interactions via common architectures (Figure S-2).

Rapidly Evolving Context

QER 1.2 identifies a number of key trends that will shape the future electricity sector, including the following: the changing generation mix; low load growth; increasing vulnerabilities to severe weather/climate change; the proliferation of new technologies, services, and market entrants; increasing consumer choice; emerging cyber/physical threats; aging infrastructure and workforce; and the growing interdependence of regulatory jurisdictions. Each topic is introduced here and discussed in more detail in Chapter I (*Transforming the Nation's Electricity System: The Second Installment of the Quadrennial Energy Review*).

Increasing Importance of "Internet of Things" (IoT) and Digitization. The IoT comprises "*sensors and actuators embedded in physical objects—from roadways to pacemakers—[that] are linked through wired and wireless networks, often using the same Internet Protocol (IP) that connects the Internet*." The rapid growth of the IoT is both a manifestation and key enabler of this major change in the economy. Electricity enables this information-intense economy, while at the same time gaining new value through digitization and interconnectedness.

Increased Productivity, Lower Load Growth. Since the 1950s, growth in U.S. electricity consumption has gradually slowed each decade due to a number of factors, including moderating population growth, improvements in the energy efficiency of buildings and industry, market saturation of certain major appliances, and a shift in the broader economy to less energy-intensive industries. Looking forward to 2040, electricity use is projected to grow slowly.

Decarbonizing the Electricity System. Since 2005, U.S. electricity system emissions have declined by 20 percent, largely due to a slowing of electricity demand growth and the accelerated deployment of lower-carbon generation. Low natural gas prices have led to substantial substitutions of lower-emitting gas for high-emitting coal. The electricity sector has been and—depending on the interplay of technology innovation, market forces, and policy—is likely to continue to be the first mover in economy-wide greenhouse gas (GHG) emissions reductions. This is in part because the electricity sector has the broadest and most cost-effective abatement opportunities of any sector, including multiple zero-carbon and low-carbon generation options—such as nuclear, hydropower, solar, wind, geothermal, biomass, and fossil generation with carbon capture and storage—as well as many operational and end-use efficiency opportunities. It will also play a major role in the levels of decarbonization needed from other sectors, such as transportation.

National Security Vulnerability. Without access to reliable electricity, much of the economy and all electricity-enabled critical infrastructures are at risk. These include our national security and homeland defense networks, which depend on electricity to carry out their missions to ensure the safety and prosperity of the American people. As U.S. policies establish new pathways to enhance economic competitiveness and environmental objectives, it is also essential that these policies work in concert with national security objectives.

Growing Importance of Backup Generation. The loss of significant economic value from even short power outages places a very high premium on the customer—as opposed to system reliability—and has helped to create a growing market for backup generation to meet individual customer needs. Such backup solutions sometimes have multiple components to ensure necessary redundancy.

Information Technology and the Electricity System. Information and communications technologies and grid-control technologies for electricity systems—both large and small scale—have evolved, enabling increased interconnection and capture of economies of scale and scope. The electricity industry's early adoption of analytical and computer techniques to coordinate the generation and transmission of power has facilitated increased interconnection and inter-utility power transfers.

A Smarter Grid. The "smart grid" refers to an intelligent electricity grid—one that uses digital communications technology, information systems, and automation to detect and react to local changes in usage, improve system operating efficiency, and, in turn, reduce operating costs while maintaining high system reliability. Smart meter infrastructure, sensors, and communication-enabled devices and controls give electricity consumers and utilities new abilities to monitor electricity consumption and potentially lower usage in response to time, local distribution, or price constraints. Smart meters also provide other benefits, including enhanced outage management and restoration, improved distribution system monitoring, and utility operational savings.

Changing Generation Profile. The national generation mix has realigned over the past few decades and is likely to continue changing. The U.S. generation fleet is transitioning from one dominated by centralized generators with high inertia and dispatchability to one that is more "hybridized," relying on a mixture of (1) traditional, centralized generation and (2) variable utility-scale and distributed renewable generation.

Aging Infrastructure. Like any infrastructure, the physical components of the U.S. electricity system are constantly aging. The continual maintenance and replacement of electricity system infrastructure components provides an important opportunity to modernize the electricity system.

Two-Way Flows. For over 100 years, the electricity system has been operated through one-way flows of electricity and information. The generation and smart grid technology innovations described earlier can reduce grid costs and improve efficiency, as well as save time and effort. These technologies have also enabled an electricity system where two-way flows are possible and more common and where digitization is a key enabler of a new range of services, including increased flexibility, higher system efficiency, reduced energy consumption, and increased consumer options and value.

Customer Engagement, New Business Models, and the Emerging Role of Aggregators. Throughout the electricity industry's development, the electricity customer was viewed as "load"—the aggregate accumulation of demand that utilities served, supported by a "ratepayer." This view of customers as load and ratepayer, largely passive because there were no real alternative options to utility service, was operative through the early 1980s. Changes in the electricity sector starting in the mid-1980s, however, have prompted utilities and emerging competitors to slowly shift their "customer as load" views to a point of view that is more customer-centric.

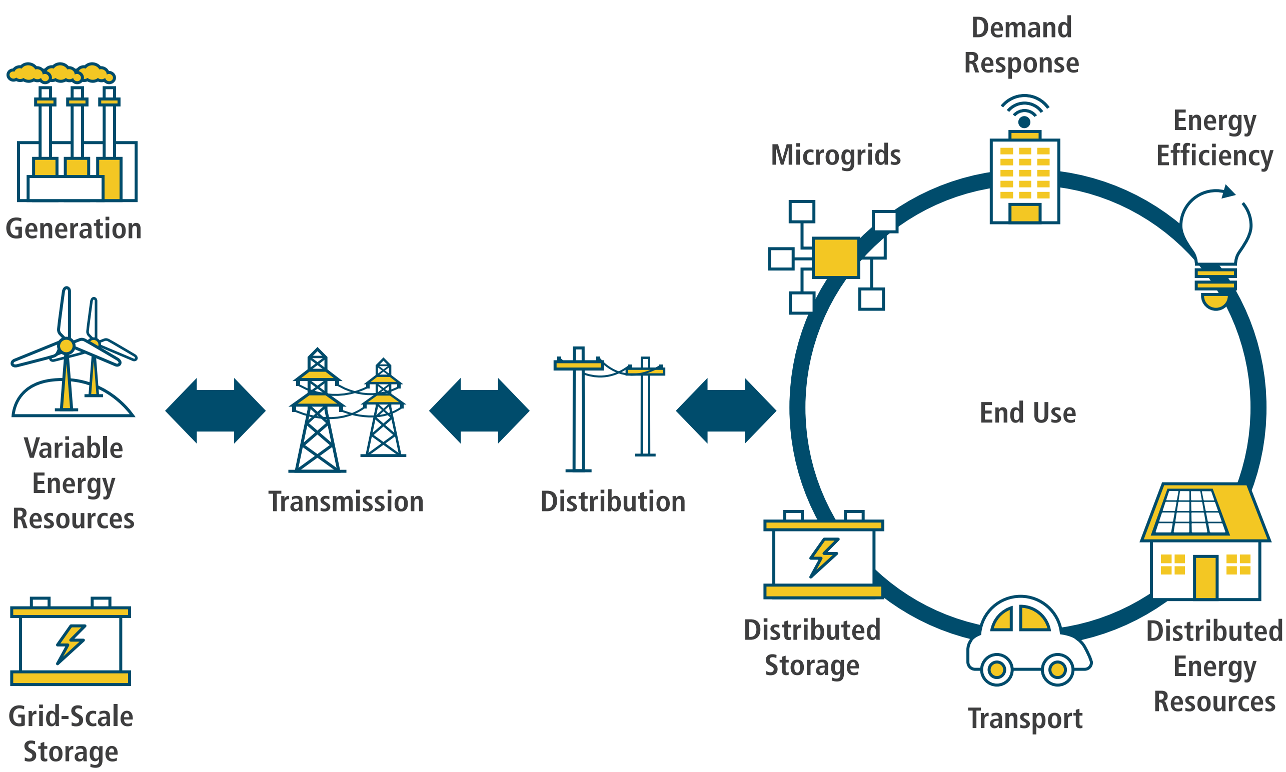
Workforce Challenges. Realizing the full potential of shifts in generation technologies, operations tools, and industry structure will require an electricity industry workforce capable of adapting and evolving to meet the needs of the 21st-century electricity sector. A skilled workforce that can build, operate, and manage a modernized grid infrastructure is an essential component for realizing the full value of a modernized electricity sector.

Extreme Weather. The increased severity of extreme weather events over time has been a principal contributor to an observed increase in the frequency and duration of U.S. power outages between 2000 and 2012. Many weather-related threats to the electricity system are increasing in frequency and intensity and are also projected to worsen in the future due to climate change.

Maximizing Economic Value and Consumer Equity

Chapter II (*Maximizing Economic Value and Consumer Equity*) discusses the role of the electricity sector in creating economic value. The electricity sector has been an economic engine for the United States for over a century, providing reliable and competitively priced electricity that is critical for the United States' productivity. The vast majority of American consumers—encompassing households, businesses, and institutions—enjoy reliable and affordable electricity that enables a modern economy and a high standard of living. Consumers now (1) can produce and consume power and increase efficiency through advanced distribution infrastructure and (2) increasingly can provide energy, capacity, and ancillary services. This changing relationship between consumers and the grid is further driving the convergence of systems, business models, services, policies, and new technologies in a development feedback loop (Figure S-3).

Figure S-3. Emerging 21st-Century Electricity Two-Way Flow Supply Chain



The emerging 21st-century power grid will incorporate responsive resources, storage, microgrids, and other technologies that enable increased flexibility, higher system efficiency, reduced energy consumption, and increased consumer options and value.

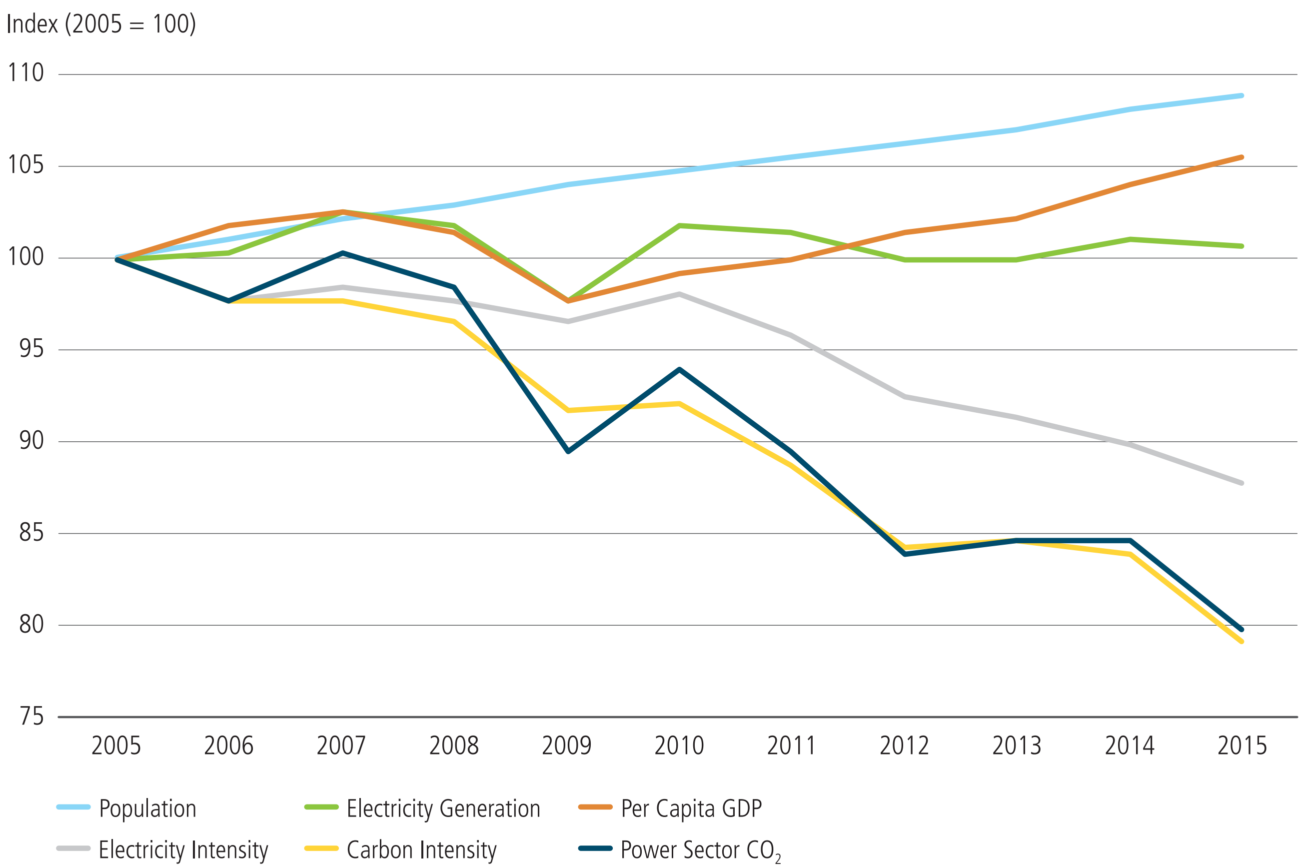
Key Findings

- Advanced metering infrastructure has had a significant impact on the nature of interactions between the electricity consumer and the electricity system, allowing a two-way flow of both electricity and information and enabling the integration of assets behind the meter into the larger electric grid.
- Interconnection standards and interoperability are critical requirements for seamless integration of grid-connected devices, appliances, and building energy-management systems, without which grid modernization and further energy efficiency gains may be hindered.
- Evolving consumer preferences for electricity services are creating new opportunities.
- The convergence of the electric grid with information and communications technology creates a platform for value creation and the provision of new services beyond energy.
- There is enormous potential for electric end-use efficiency improvement based on (1) technical analyses, and (2) the differences in energy efficiency performance between states and utilities with and without ambitious electric end-use efficiency policies and programs.
- Tribal lands have the highest rates of unelectrified homes in the contiguous United States and Alaska. The extreme rurality of some tribal communities, coupled with high levels of poverty, presents an economic challenge for the electric utilities trying to serve them.
- Optimization of behind-the-meter assets will require the design of coordination, communication, and control frameworks that can manage the dispatch of these devices in a way that is both economical and secure, while maintaining system reliability.
- Mobile, Internet-connected devices foster new ways of consumer engagement, as well as enable consumers to have more efficient and real-time management of their behind-the-meter assets.
- Consumers and third-party merchants who produce electricity can provide economic, environmental, and operational benefits.
- New grid services, modern technologies, and evolving system topologies and requirements are straining traditional methods of valuation. Appropriate valuation of the grid services by various technologies is technically and administratively challenging, and it may depend on spatial and temporal variables unique to different utilities, states, and regions.
- Currently, about 90 percent of residential, 60 percent of commercial, and 30 percent of industrial energy consumption are used in appliances and equipment that are subject to Federal minimum efficiency standards implemented, and periodically updated, by the Department of Energy. Between 2009 and 2030, these cost-effective standards are projected to save consumers more than $545 billion in utility costs, reduce energy consumption by 40.8 quads, and reduce carbon dioxide emissions by over 2.26 billion metric tons.
- Miscellaneous electric loads—devices that are often inadequately addressed by minimum standards, labeling, and other initiatives—are expected to represent an increasing share of total electricity demand, particularly for the residential and commercial sectors.
- Connected devices and energy-management control systems are decreasing in cost and improving in functionality, although their market penetration is still low, particularly in residences and small-to-medium-sized commercial buildings. These new technologies and systems, as well as the broader "Internet of Things," provide a wide range of options for consumers to manage their energy use, either passively using automated controls or through active monitoring and adjustment of key systems.
- Energy-management control systems with communication capabilities are increasing opportunities for demand response services in support of grid operations. Third-party aggregators and other business models are facilitating the expanded use of demand response, but the regulatory environment remains unsettled in many states.
- Lower-income households use less energy but pay a considerably higher fraction of their after-tax income for electricity services.
- Insufficient broadband access in rural areas could inhibit the deployment of grid-modernization technologies and the economic value that these technologies can create.

Building a Clean Electricity Future

A clean electricity system reduces air and water pollution, lowers GHG emissions, and limits the water and land-use impacts to the ecosystem. Addressing climate change will require the United States to greatly reduce its carbon emissions, while simultaneously addressing new grid-management challenges that have arisen due to recent trends in electricity generation and demand, the changing climate, and the national security implications of grid dependency. Keeping this context in mind, Chapter III (*Building a Clean Electricity Future*) explores the essential elements of a clean electricity system and identifies the policy, market, and technology innovations needed to achieve it. In short, we have made substantial progress in reducing the environmental impacts of the electricity system, but much work remains.

Figure S-4. Trendlines in CO_2 Emissions Drivers, 2005–2015



The population growth, per capita gross domestic product (GDP), and electricity intensity of the economy all factor into total U.S. electricity demand. While growth in population and per capita GDP has placed upward pressure on power sector demand, this growth has been partially offset by a decline in the electricity intensity of the economy.

Key Findings

- A clean electricity system reduces air and water pollution, lowers greenhouse gas (GHG) emissions, minimizes waste, and limits the impact to the ecosystem in areas such as water and land use.
- Deep decarbonization of the electricity system is essential for meeting climate goals; this has multiple economic benefits beyond those of environmental responsibility.
- The United States is the largest producer and consumer of environmental technologies. In 2015, the U.S. environmental technology and services industry employed 1.6 million people, had revenues of $320 billion, and exported goods and services worth $51 billion.
- Though the U.S. population and economy have grown, between 1970 and 2014, aggregate emissions of common air pollutants from the electric power sector dropped 74 percent, even as electricity generation grew by 167 percent.
- U.S. carbon dioxide (CO_2) emissions from the power sector have substantially declined. Between 2006 and 2014, 61 percent of these reductions in CO_2 were attributed to switching from coal- to gas-fired power generation, and 39 percent were attributed to increases in zero-emissions generation.
- The increasing penetration of zero-carbon variable energy resources and deployment of clean distributed energy resources (including energy efficiency) are critical components of a U.S. decarbonization strategy.
- It is beneficial to a clean electricity system to have many options available, as many of the characteristics of clean electricity technologies complement each other.
- Currently, 29 states and Washington, D.C., have a renewable portfolio standard, and 23 states have active and binding energy efficiency resource standards for electricity. States that have actively created and implemented such electricity resource standards and other supporting regulatory policies have seen the greatest growth in renewables and efficiency.
- The integration of variable renewables increases the need for system flexibility as the grid transitions from controllable generation and variable load to more variable generation and the need and potential for controllable load. There are a number of flexibility options, such as demand response (DR), fast-ramping natural gas generation, and storage.
- Energy efficiency is a cost-effective component of a clean electricity sector. The average levelized cost of saved electricity from energy efficiency programs in the United States is estimated at $46 per megawatt-hour (MWh), versus the levelized cost of electricity for natural gas combined-cycle generation, with its sensitivity to fuel prices, at $52–$78/MWh.
- Electricity will likely play a significant role in the decarbonization of other sectors of the U.S. economy as electrification of transportation, heating, cooling, and industrial applications continues. In the context of the second installment of the Quadrennial Energy Review, electrification includes both direct use of electricity in end-use applications and indirect use, whereby electricity is used to make intermediate fuels such as hydrogen.
- Realizing GHG emissions reductions and other environmental improvements from the electricity system to achieve national goals will require additional policies combined with accelerated technology innovation.
- Improved understanding of the electricity system and its dynamics through enhancements in data, modeling, and analysis is needed to provide information to help meet clean objectives most cost effectively.
- Decades of Federal, state, and industry innovation investments have significantly contributed to recent cost reductions in renewable energy and energy efficiency technologies.
- Innovation in generation, distribution, efficiency, and DR technologies is essential to a low-carbon future. Innovation combined with supportive policies can provide the signal needed to accelerate deployment of clean energy technologies, providing a policy pull to complement technology push.

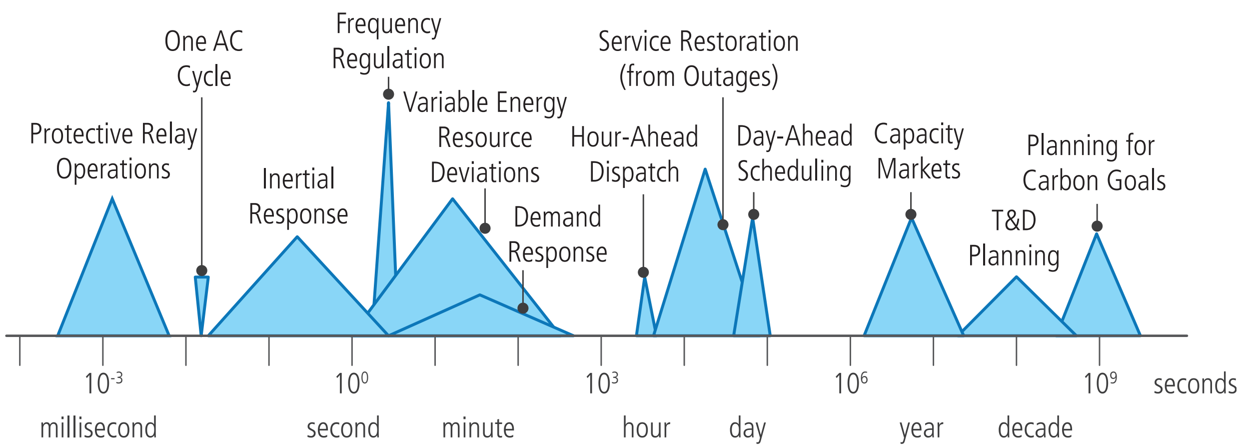
Key Findings (continued)

- Nuclear power currently provides 60 percent of U.S. zero-carbon electricity, but existing nuclear merchant plants are having difficulty competing in restructured electricity markets due to low natural gas prices and flat or declining electricity demand. Since 2013, 6 nuclear power reactors have shut down earlier than their licensed lifetime, and 10 others have announced plans to close in the next decade. In 2016, two states, Illinois and New York, put policies in place to incentivize the continued operation of existing nuclear plants, and these policies may prevent 6 of the 10 announced closures.
- Enhanced oil recovery operations in the United States are commercially demonstrated geologic storage and could provide a market pull for the deployment of carbon capture, utilization, and storage (CCUS).
- Federal laws currently limit the ability of regulated utilities to utilize Federal tax credits in the same manner as private and unregulated developers. Publicly owned clean energy projects cannot benefit from the clean energy tax credits because tax equity investors cannot partner directly with tax-exempt entities to monetize tax credits.
- Low-income and minority communities are disproportionately exposed to air quality and water quality issues associated with electric power generation. Compared to the U.S. population overall, there is a greater concentration of minorities living within a 3-mile radius of coal- and oil-fired power plants. In these same areas, the percentage of the population below the poverty line is also higher than the national average.
- Some energy technologies that reduce GHG emissions, such as CCUS, concentrated solar power, and geothermal generation, have the potential to increase energy's water intensity; others, such as wind and photovoltaic solar power, can lower it. Dry cooling can reduce water intensity but may increase overall GHG emissions by decreasing generation efficiency. Though there can be a strong link between energy and water efficiency in energy technologies, many research, development, demonstration, and deployment funding criteria do not incorporate water-use or water-performance metrics. Designing technologies and optimizing operations for improved water performance can have both energy and water benefits.
- There is currently no centralized permanent-disposal facility for used nuclear fuel in the United States, so this radioactive material is stored at reactor sites in 35 states awaiting development of consolidated storage facilities and/or geologic repositories.
- Coal combustion residuals, such as coal ash and scrubber slurry, are the second most abundant waste material in the United States, after household waste.
- There is a range of decommissioning needs for different types of power generation facilities.

Ensuring Electricity System Reliability, Security, and Resilience

Chapter IV (*Ensuring Electricity System Reliability, Security, and Resilience*) addresses a range of possible risks to the electricity system and the broader economy and suggests options to mitigate and prepare for these risks. Traditional electricity system operations are evolving in ways that could enable a more dynamic and integrated grid. The growing interconnectedness of the grid's energy, communications, and data flows creates enormous opportunities; at the same time, it creates the potential for a new set of risks and vulnerabilities. Also, the emerging threat environment—particularly with respect to cybersecurity and increases in the severity of extreme weather events—poses challenges for the reliability, security, and resilience of the electricity sector, as well as its traditional governance and regulatory regimes.

Figure S-5. System Reliability Depends on Managing Multiple Event Speeds



Capacity markets, day-ahead scheduling, and hour-ahead dispatch are well-understood tools for managing supply variability (mid-right axis). Beyond capacity contracts, traditional transmission and distribution (T&D) system long-term planning methods work to map and price investment requirements to ensure grid reliability (right end of axis). However, the widespread integration of variable energy resources significantly expands the time dimensions in which grid operators must function, ranging from hourly to minute to second intervals (mid-left axis). And, in a world of subsecond decision making (i.e., inertial response, one alternating current (AC) cycle, and protective relay operations), dispatch effectiveness will require the integration of automated grid management (left end of axis).

Key Findings

- The reliability of the electric system underpins virtually every sector of the modern U.S. economy. Reliability of the grid is a growing and essential component of national security. Standard definitions of reliability have focused on the frequency, duration, and extent of power outages. With the advent of more two-way flows of information and electricity—communication across the entire system from generation to end use, controllable loads, more variable generation, and new technologies such as storage and advanced meters—reliability needs are changing, and reliability definitions and metrics must evolve accordingly.
- The time scales of power balancing have shifted from daily to hourly, minute, second-to-second, or millisecond-to-millisecond at the distribution end of the supply chain, with the potential to impact system frequency and inertia and/or transmission congestion. The demands of the modern electricity system have required, and will increasingly require, innovation in technologies (e.g., inverters), markets (e.g., capacity markets), and system operations (e.g., balancing authorities).
- Electricity outages disproportionately stem from disruptions on the distribution system (over 90 percent of electric power interruptions), both in terms of the duration and frequency of outages, which are largely due to weather-related events. Damage to the transmission system, while infrequent, can result in more widespread major power outages that affect large numbers of customers with significant economic consequences.
- As transmission and distribution system design and operations become more data intensive, complex, and interconnected, the demand for visibility across the continuum of electricity delivery has expanded across temporal variations, price signals, new technology costs and performance characteristics, social-economic impacts, and others. However, deployment and dissemination of innovative visibility technologies face multiple barriers that can differ by the technology and the role each plays in the electricity delivery system.
- Data analysis is an important aspect of today's grid management, but the granularity, speed, and sophistication of operator analytics will need to increase, and distribution- and transmission-level planning will need to be integrated.
- The leading cause of power outages in the United States is extreme weather, including heat waves, blizzards, thunderstorms, and hurricanes. Events with severe consequences are becoming more frequent and intense due to climate change, and these have been the principal contributors to an observed increase in the frequency and duration of power outages in the United States.
- Grid owners and operators are required to manage risks from a broad and growing range of threats. These threats can impact almost any part of the grid (e.g., physical attacks), but some vary by geographic location and time of year. Near-term and long-term risk management is increasingly critical to the ongoing reliability of the electricity system.
- The current cybersecurity landscape is characterized by rapidly evolving threats and vulnerabilities, juxtaposed against the slower-moving deployment of defense measures. Mitigation and response to cyber threats are hampered by inadequate information-sharing processes between government and industry, the lack of security-specific technological and workforce resources, and challenges associated with multi-jurisdictional threats and consequences. System planning must evolve to meet the need for rapid response to system disturbances.
- Other risk factors stem from the increasing interdependency of electric and natural gas systems, as natural gas–fired generation provides an increasing share of electricity. However, coordinated long-term planning across natural gas and electricity can be challenging since the two industries are organized and regulated differently.
- As distributed energy resources become more prevalent and sophisticated—from rooftop solar installations, to applications for managing building electricity usage—planners, system operators, and regulators must adapt to the need for an order of magnitude increase in the quantity and frequency of data to ensure the continuous balance of generation and load.
- Demand response and flexibility technologies—such as hydropower and storage—offer particularly flexible grid resources that can improve system reliability, reduce the need for capital investments to meet peak demand, reduce electricity market prices, and improve the integration of variable renewable energy resources. These resources can be used for load reduction, load shaping, and consumption management to help grid operators mitigate the impact of variable and distributed generation on the transmission and distribution systems.

Key Findings (continued)

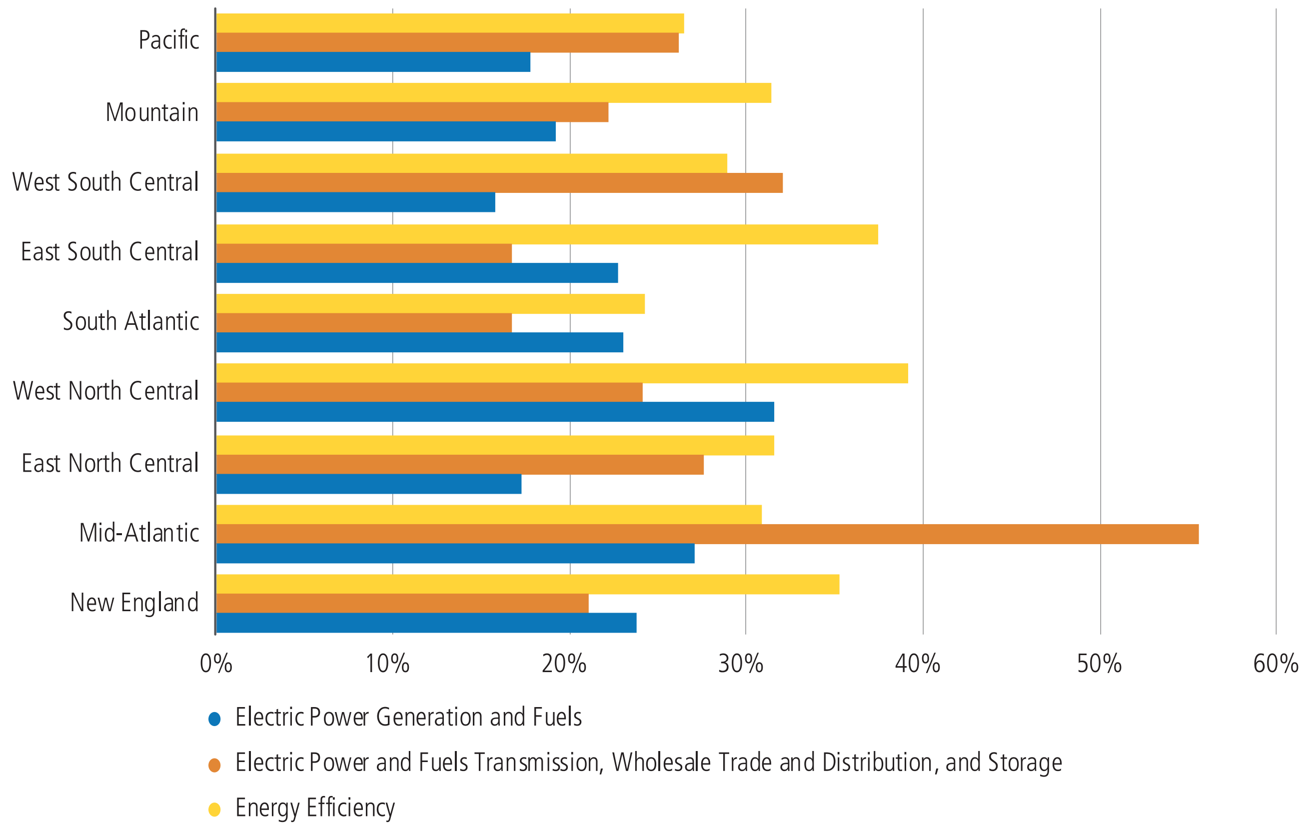
- Information and communications technologies are increasingly utilized throughout the electric system and behind the meter. These technologies offer advantages in terms of efficient and resilient grid operations, as well as opportunities for consumers to interact with the electricity system in new ways. They also expand the grid's vulnerability to cyber attacks by offering new vectors for intrusions and attacks—making cybersecurity a system-wide concern.
- There are no commonly used metrics for measuring grid resilience. Several resilience metrics and measures have been proposed; however, there has been no coordinated industry or government initiative to develop a consensus on or implement standardized resilience metrics.
- Low-income and minority communities are disproportionately impacted by disaster-related damage to critical infrastructure. These communities with fewer resources may not have the means to mitigate or adapt to natural disasters, and they disproportionately rely on public services, including community shelters, during disasters.

This chapter was developed in conjunction with the closely related and recently published "Joint United States-Canada Electric Grid Security and Resilience Strategy."

Electricity Workforce of the 21st Century: Changing Needs and New Opportunities

Chapter V (*Electricity Workforce of the 21st Century: Changing Needs and New Opportunities*) provides an overview of current and projected employment in and related to the electricity sector. The chapter also discusses options to assist workers and develop a workforce that has the skills to build, maintain, and operate the electricity system of the future. The broader changes in the electricity industry have created both new opportunities and new challenges for the electricity industry workforce, including new workforce opportunities in the renewable energy industry and information communications technologies, as well as the challenges of the skills gap for deploying and operating new technologies, the shift in the geographic location of jobs, and the need to recruit and retain an inclusive workforce. The electricity industry is the dominant consumer of coal, natural gas, and renewable energy technologies, so changes in electricity industry demand for these resources can cause regional and sectoral dislocations in these industries. Each industry has distinctive workforce skills requirements and geographic concentrations, so employment gains in one industry do not always translate to opportunities for those workers affected by employment loss in other industries that may be geographically distant and require different skills.

Figure S-6. Percentage of Employers Reporting Very High Hiring Difficulty by Census Region and Subsector, Q4 2015



Over half of employers in the Mid-Atlantic region report very high difficulty hiring in the electric power and fuels transmission, wholesale trade and distribution, and storage subsector, while no more than 32 percent of employers in other regions reported hiring difficulty in this field. The Mid-Atlantic also reports among the highest rates of difficulty hiring in the energy efficiency and electric power generation and fuels industries.

Key Findings

- Over 1.9 million people are employed in jobs related to electric power generation and fuels, while 2.2 million people are working in industries directly or partially related to energy efficiency.
- Job growth in renewable energy is particularly strong. Employment in the solar industry has grown over 20 percent annually from 2013 to 2015. From 2010 to 2015, the solar industry created 115,000 new jobs. In 2016, approximately 374,000 individuals worked, in whole or in part, for solar firms, with more than 260,000 of those employees spending most of their time on solar. There were an additional 102,000 workers employed at wind firms across the Nation. The solar workforce increased by 25 percent in 2016, while wind employment increased by 32 percent.
- The oil and natural gas industry experienced a large net increase in jobs over the last several years, adding 80,000 jobs from 2004 to 2014. Unlike coal production, natural gas production is projected to increase over the coming decades under a business-as-usual scenario, sustaining natural gas industry employment.
- Employment in the natural gas extraction industry is regionally and temporally volatile; 28,000 jobs were lost between January 2015 and August 2016. Shifts in locations pose challenges for employees and the economies of the areas where they live and work.

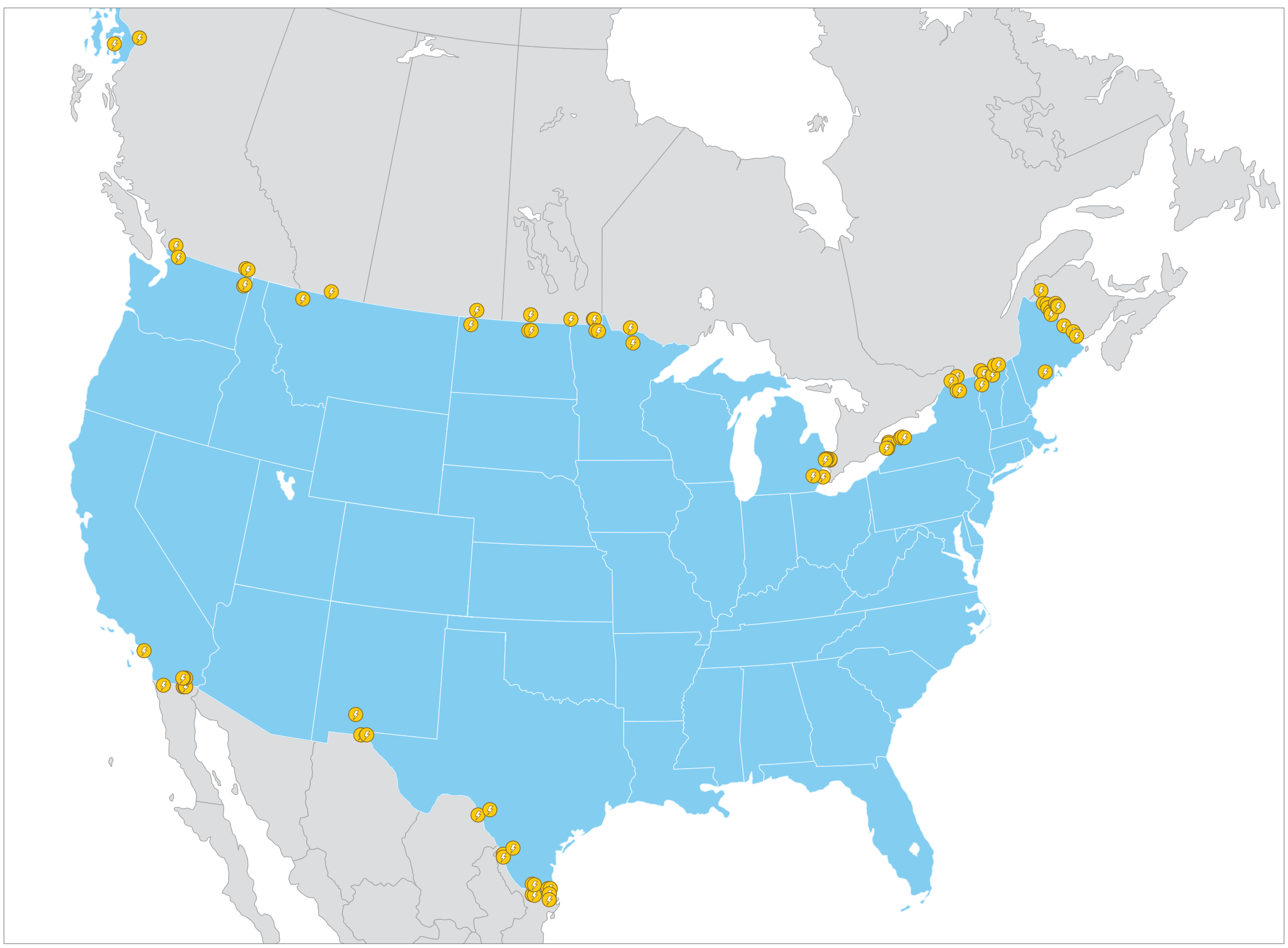
Key Findings (continued)

- Between 1985 and 2001, coal production increased 28 percent as industry employment fell by 59 percent due to efficiencies gained by shifting production from Appalachia to the West.
- Aside from a minor employment increase from 2000 to 2011, 141,500 domestic coal jobs were lost between 1985 and 2016, and the industry shrank by 60 percent. In 2015, annual coal production was at its lowest level since 1986, and it is forecast to continue declining over the coming decades. As of November 2016, according to data from the Bureau of Labor Statistics, the coal mining industry employs about 53,000 people.
- Despite ongoing economic challenges in the Appalachian region, the non-highway appropriated budget for the Appalachian Regional Commission (ARC), a federally funded regional economic development agency, has fallen from roughly $600 million in the early 1970s to around $100 million in the 1980s and has remained roughly constant until 2016. The ARC budget recently increased from $90 million in fiscal year 2015 to nearly $150 million in fiscal year 2016.
- The Abandoned Mine Lands Reclamation Fund's (AML Fund's) inability to fully support the reclamation of lands disrupted by the coal mining industry has the potential to leave communities in regions with declining local revenues with polluted and unsafe lands and few means to repair the damage. The AML Fund's increased ability to support coal mine reclamation would provide local employment opportunities and help coal communities transition to new industries.
- The continued fiscal difficulties of coal miner pensions threaten the solvency of the Pension Benefit Guaranty Corporation, a Federal agency that insures private-sector pension funds and is funded out of insurance premiums paid by member funds.
- Proliferation of information and communications technologies and new technologies like distributed generation, smart home devices, and electric battery storage have led to new businesses and employment opportunities, which will require a wide array of new skills.
- The electricity industry will need a cross-disciplinary power grid workforce that can comprehend, design, and mange cyber-physical systems; the industry will increasingly require a workforce adept in risk assessment, behavioral science, and familiarity with cyber hygiene.
- A dip in the number of electricity industry workforce training programs in the 1980s has contributed to a currently low number of workers in the electric utilities able to move into middle and upper management positions—creating a workforce gap as the large number of baby boomers retire.
- Workforce retirements are a pressing challenge. Industry hiring managers often report that lack of candidate training, experience, or technical skills are major reasons why replacement personnel can be challenging to find—especially in electric power generation.
- Electricity and related industries employ fewer women and minorities than the national average, but have a higher proportion of veterans. Only 5 percent of the boards of utilities in the United States included women, and approximately 13 percent of board members among the top 10 publicly owned utilities were African American or Latino. Underrepresentation in or lack of access to science, technology, engineering, and mathematics educational opportunities and programs contribute to the underrepresentation of minorities and women within the electricity industry.
- From 1995 to 2013, the number of injuries per 100 employee-years in the electricity utility industry decreased from 4.7 to 1.3. However, line workers continue to experience hazardous working conditions. In 2014, electrical power line installers and repairers suffered 25 fatal work injuries—a rate of 19 per 100,000 full-time equivalent workers, which is more than five times the national fatal work injury rate.
- While data on energy sector workforce are improving, there are still major shortcomings in the data availability, precision, and categorization of energy sector jobs.

Enhancing Electricity Integration in North America

Chapter VI (*Enhancing Electricity Integration in North America*) details the interconnectivity of the U.S., Canadian, and Mexican electricity systems and opportunities for enhancing integration. The potential for electricity integration to provide economic benefits and to support the development of more modern and resilient energy infrastructure has been a longstanding theme for North American diplomacy. Earlier this year at the North American Leaders' Summit, President Barack Obama, President Enrique Peña Nieto, and Prime Minister Justin Trudeau signed a statement agreeing to collaborate on cross-border transmission projects in order to achieve the mutual goal of advancing clean and secure power. The extensive electricity integration that already exists between the United States and Canada, and the potential to increase existing integration between the United States and Mexico, suggests that North America has much to gain from collaborative planning, strategy, and cooperation in the power sector.

Figure S-7. Major International Electricity Interconnections across North America



Key Findings

- Integration of the Canadian, Mexican, and U.S. power systems historically occurred by gradual, ad-hoc, and regional adjustments implemented by an array of regional, public, and private stakeholders, reflecting the complex and fragmented jurisdictions in all countries. Many opportunities for enhanced integration have included a collection of stakeholders and were pursued on a subregional basis.
- One model for power sector collaboration across national borders is demonstrated by the reliability planning under the North American Electric Reliability Corporation; however, this engagement has been limited to Canada, the United States, and the Baja California region of Mexico. The Canadian, Mexican, and U.S. governments have all made significant climate commitments and have indicated a desire to shift toward greater renewable energy penetration. In June 2016, the United States, Canada, and Mexico announced a goal for North America to strive to achieve 50 percent clean power generation by 2025. Greater cross-border integration could be a tool to maximize gains from the deployment of clean energy generation and energy efficiency, but the complexity and current asymmetry of national and subnational policy frameworks may impede implementation.
- The design of domestic U.S. clean energy policies, both at the Federal and state level, has implications for cross-border trade and continental emissions reductions. Currently, there are significant disparities between U.S. states' policies for recognition or exclusion of international clean energy imports.
- Continued study of the context and levels of integration of each subregional, cross-border interconnection will allow for a deeper understanding of policies that have shaped current levels of cross-border trade.
- Canada has additional hydropower resources that could be exported to the United States to provide a reliable source of firm, low-carbon energy. There are concerns among stakeholders that increased imports of Canadian hydropower could reduce U.S. clean energy competitiveness; however, there are examples of arrangements where Canadian hydropower decreases curtailments of U.S. clean resources.
- Trade has been increasing across the North American bulk power system, but cross-border flows, especially between Canada and the United States, are now using the full capacity of existing transmission infrastructure.
- Under a low-carbon future scenario, current modeling results show that transmission with Canada becomes increasingly important for sustaining emissions reductions and has a significant impact on the generation mix in border regions.
- While many electricity system models exist for the United States (and in some cases, the United States and Canada), detailed modeling tools to explore the economic, social, and/or reliability impacts of electricity trade across all of North America are currently insufficient to inform opportunities for enhancing integration.
- While extensive integration between the United States and Canada can inform the potential for increased future U.S.-Mexico integration, these situations are fundamentally dissimilar in four main ways: (1) the lack of a dominant exporting country on the U.S.-Mexican border, (2) the different regional approaches to integration on the U.S. side, (3) the nascent regulatory framework in Mexico, and (4) the differing legal instruments for open-access transmission agreements and reliability coordination between the United States and Mexico.
- Mexico's ongoing electricity utility industry reforms could have significant impacts on the future of cross-border integration. The reforms are focused on the overall goal of competitiveness, with the twin objectives of reducing electricity costs and developing more clean energy. A transition in Mexico from oil to natural gas in electricity generation could have significant impacts on the manufacturing sector, reducing electricity prices, boosting manufacturing output, and increasing overall gross domestic product for Mexico.
- Mexico's increasing importation of U.S. natural gas could be an economic and environmental opportunity for both sides by offsetting expensive and high greenhouse gas–emitting diesel generation in Mexico and creating economic opportunities for U.S. exporters. The resulting reduction in electricity costs in Mexico could also boost overall North American competitiveness.
- The Electric Reliability Council of Texas could benefit from greater integration with Mexico through access to enhanced imports, or as a business opportunity for power exporters.
- California's ambitious clean energy policy provides an opportunity for energy exporters in Mexico, especially in the Baja California region, to supply clean energy, dispatchable power, or essential reliability services.

A 21st-Century Electricity System: Conclusions and Recommendations

Chapter VII (*A 21st-Century Electricity System: Conclusions and Recommendations*) highlights many recommendations that are enablers of the modernization and transformation necessary to protect and enhance the value of the U.S. electricity system. The recommendations build on the analysis and findings in earlier chapters. Many of the recommendations will provide the incremental building blocks for longer-term, planned changes and activities, undertaken in conjunction with state and local governments, policymakers, industry, and other stakeholders. The policy, research, and investment choices made today will establish critical pathways for decades.

Recommendations in Brief

QER 1.2 provides 76 recommendations divided into six sections. The first section addresses recommendations that are crosscutting, addressing all three high-level goals of economic competitiveness, environmental responsibility, and national security. Following this section in the QER 1.2, three sections make more specific recommendations that will help meet these strategic objectives: maximizing economic value and consumer equity; building a clean electricity future; and ensuring electricity system reliability, security, and resilience. There are also recommendation sections on the electricity sector workforce and on enhancing electricity integration in North America. These recommendations are summarized here, with full details in Chapter VII (*A 21st-Century Electricity System: Conclusions and Recommendations*).

Key Crosscutting Recommendations to Support the Security and Reliability of the Electricity System

Protect the Electricity System as a National Security Asset. The Federal Power Act provides a statutory foundation for an electricity reliability organization to develop reliability standards for the bulk power system. Pursuant to this authority, the Federal Energy Regulatory Commission (FERC) has certified the North American Electric Reliability Corporation (NERC) as the electric reliability organization. Under this arrangement, NERC and FERC have put into place a comprehensive set of binding reliability standards for the bulk power system over the past decade, including standards on cybersecurity and physical security. However, the Federal oversight authority is limited: FERC can approve or reject NERC-proposed reliability standards, but it cannot author or modify reliability standards.

The nature of a national security threat, however, as articulated in the Fixing America's Surface Transportation Act (FAST Act), stands in stark contrast to other major reliability events that have caused regional blackouts and reliability failures in the past. In the current environment, the U.S. grid faces imminent danger from cyber attacks, absent a discrete set of actions and clear authorities to inform both responses and threats. Widespread disruption of electric service because of a transmission failure initiated by a cyber attack at various points of entry could undermine U.S. lifeline networks, critical defense infrastructure, and much of the economy; it could also endanger the health and safety of millions of citizens. Also, natural gas plays an increasingly important role as fuel for the Nation's electricity system; a gas pipeline outage or malfunction due to a cyber attack could affect not only pipeline and related infrastructures, but also the reliability of the Nation's electricity system.

- **Amend Federal Power Act authorities to reflect the national security importance of the Nation's electric grid.** Grid security is a national security concern—the clear and exclusive purview of the Federal Government. The Federal Power Act, as amended by the FAST Act, should be further amended by Congress to clarify and affirm the Department of Energy's (DOE's) authority to develop preparation and response capabilities that will ensure it is able to issue a grid-security emergency order to protect critical electric infrastructure from cyber attacks, physical incidents, electromagnetic pulses (EMPs), or geomagnetic storms. In this regard, Federal authorities should include the ability to address two-way flows that create vulnerabilities across the entire system. DOE should be supported in its development of exercises and its facilitation of the penetration testing necessary to fulfill FAST Act emergency authorities. In the area of cybersecurity, Congress should provide FERC with authority to modify NERC-proposed reliability standards—or to promulgate new standards directly—if it finds that expeditious action is needed to protect national security in the face of fast-developing new threats to the grid. This narrow expansion of FERC's authority would complement DOE's national security authorities related to grid-security emergencies affecting critical electric infrastructure and defense-critical electricity infrastructure. This approach would maintain the productive NERC-FERC structure for developing and enforcing reliability standards, but would ensure that the Federal Government could act directly if necessary to address national security issues.

- **Collect information on security events to inform the President about emergency actions, as well as imminent dangers.** DOE should collect targeted data on critical cyber, physical, EMP, and geomagnetic disturbance events and threats to the electric grid to inform decision making in the event of an emergency or to inform the anticipatory authorities in the FAST Act. DOE should concurrently develop appropriate criteria, processes, and definitions for collecting these targeted data using a dedicated information protection program to safeguard utility data consistent with FERC rules. Reporting will be done on a confidential basis. Updating will be required to address evolving threats. DOE will coordinate the development of analytical data-surveillance and data-protection tools with the National Labs, states, universities, industry, Federal agencies, and other organizations as appropriate.
- **Adopt integrated electricity security planning and standards.** FERC should, by rule, adopt standards requiring integrated electricity security planning on a regional basis to the extent consistent with its statutory authority. Such requirements would enhance DOE's effectiveness in carrying out its responsibilities and authorities to address national security imperatives and new vulnerabilities created by (1) two-way flows of information and electricity and (2) the transactive role of customers and key suppliers (such as those providing stored fuel for strategic generators). Important national security considerations warrant careful consideration of how generation, transmission, distribution, and end-user assets are protected from cybersecurity risks. Vulnerabilities of distribution and behind-the-meter assets, which may provide an increasing number of potential entry points for access to utility control systems, are threats that can adversely affect the operation of the transmission system; for these vulnerabilities, a careful review of protections is required. To adequately address and support the security requirements of the FAST Act and DOE's implementation of the FAST Act, this review should be performed on an integrated basis, rather than separating the review into bulk power system and other assets.

  To ensure that there are no unnecessary vulnerabilities associated with state-to-state or utility-to-utility variations in protections, integrated electricity security planning should be undertaken to cover the entire United States, including Alaska, Hawaii, and U.S. territories. FERC should consider having existing regional organizations undertake such planning, as it deems appropriate. FERC should evaluate whether the costs of implementing security measures identified in the integrated electricity security plan are appropriate for regional cost allocation, where such measures are found to enhance the security of the regional transmission electric system.

  To the extent necessary, appropriate statutes should be amended to clearly authorize FERC to adopt such integrated electricity security planning requirements. However, FERC should immediately begin to advance this initiative to the maximum extent possible under its current authority by initiating a dialogue, including discussions with DOE and state authorities, and driving consensus on integrated electricity security plans.

- **Assess natural gas/electricity system infrastructure interdependencies for cybersecurity protections.** DOE, pursuant to FAST Act authorities and in coordination with FERC, should assess current cybersecurity protections for U.S. natural gas pipelines and associated infrastructure to determine whether additional or mandatory measures are needed to protect the electricity system. If the assessment concludes that additional cybersecurity protections—including mandatory cybersecurity protocols—for natural gas pipelines and associated infrastructure are necessary to protect the electricity system, such measures and protocols should be developed and implemented. This work should build on existing assessments, including those underway at the Transportation Security Administration.

Increase Financing Options for Grid Modernization. Estimates of total investment requirements necessary for grid modernization range from a low of about $350 billion to a high of about $500 billion. Grid modernization is the platform for the 21st-century electricity system, bringing significant value associated with lower electricity bills due to fuel and efficiency savings, more electricity choices, and fewer and shorter outages. The Federal Government currently plays a role in providing tax incentives for deployment of clean energy technologies, as well as Federal credit assistance to facilitate early deployment of innovative technologies.

- **Expand DOE's loan guarantee program and make it more flexible to assist in the initial deployment of innovative grid technologies and systems.** The design of the current DOE loan guarantee program is focused primarily on financing deployment of innovative generation technologies. Most DOE loan guarantee recipients, for example, are structured as special project entities that can raise equity outside of regulated business structures and can provide credit security in the form of power purchase agreements. This financing model is not amenable to grid modernization financing by regulated entities, especially in cases of some technological uncertainty associated with initial commercial deployments. In addition, there will be an ongoing need for innovation in grid technologies beyond the likely availability of current DOE loan guarantee authority. Also, the limitations of the loan program restrict the program to a very small and ever-changing portion of new transmission capacity; more projects and innovation are necessary to transform the grid.

  Modifications to the current DOE Title XVII Loan Guarantee Program are needed to (1) reduce restrictions on numbers/types of projects and time frames (e.g., in order to adequately address innovative transmission capacity needs) and (2) provide clear statutory authority for lending to other public or public/private entities that support transmission and other grid modernization projects (e.g., state agencies, regional power pools) through on-lending or equity investing. By their nature, transmission projects, especially big projects, involve many entities and jurisdictions. Statutory clarification is needed on indirect lending authorities to such entities for multi-jurisdictional projects.

  Some of the benefits of grid modernization will be realized over time as the electricity system itself is changed by technology and market innovations. Additional funding resources would bridge the gap between investment costs and realization of benefits and would enable utilities to invest in grid modernization. A relatively low-cost, permanent Federal financing system could be established by setting up a revolving loan fund with one-time seed capital.

Increase Technology Demonstrations and Utility/Investor Confidence. The future electric grid will require that utilities deploy a wide range of new, capital-intensive technologies. Primary technologies are needed to support increased reliability, security, value creation, consumer preferences, and system optimization and integration at the distribution level. Demonstrating the technical readiness and economic viability of advanced technologies is needed to inspire the confidence of utilities and investors.

- **Significantly expand existing programs to demonstrate the integration and optimization of distribution system technologies.** The complexity of the issues facing distribution systems—including new technologies, the need for systems approaches, and geographical differences in markets and regulatory structures—points to a significant need for multiple "solution sets" to enable two-way electricity flows on distribution systems, enhance value, maximize clean energy opportunities, optimize grid operations, and provide secure communications. Building on existing demonstration programs and reflecting the Administration's commitment to the doubling of Federal clean energy innovation over 5 years as part of its Mission Innovation initiative, DOE should develop a focused, cost-shared program for qualifying utilities to demonstrate advanced distribution system technologies at the community scale, including advanced voltage control/optimization systems; dynamic protection schemes to manage reverse power flows, communications, sensors, storage, switching, and smart-inverter networks; and advanced distribution-management systems, including automated substations.

  Demonstrations supported by the cost-shared, cooperative agreement program would be specifically designed to inform standards and regulations and increase regulatory and utility confidence in key technologies or technology systems. Under this program, utilities would have to make a positive business case for projects and obtain regulatory approvals for their proposed demonstrations. Preference would be given to multi-utility partnerships with diverse customer profiles and to projects that promote education and training in key academic disciplines that are essential for distribution system transformation. Cybersecurity plans for all projects would be required and supported by programmatic review of plans and deployments.

  Existing DOE programs, including advanced distribution-management systems, microgrids, communications and sensors, storage, and cybersecurity, should be leveraged to provide technical assistance regarding technological issues, planning and performance evaluation, and institutional needs. A percentage of funding could be dedicated to small, publicly owned utilities. The program should be of sufficient size to have a material impact; it should start in fiscal year 2018 and be ramped up over the time period identified in the Mission Innovation initiative.

Build Capacity at the Federal, State, and Local Levels. The 21st-century electricity system is becoming increasingly transactive, and properly valuing attributes is key to an efficient system. Application of lessons learned that pair economic and system analysis will lead to a power system that cost-effectively serves customers while providing nationally valued public goods (e.g., reliability, resilience, and acceptable environmental performance).

Advances in electricity technologies (i.e., smart grid processes and solutions) require enhanced capabilities in human resources to ensure the cost-effective selection, deployment, and operations of key technologies.

- **Provide funding assistance to enhance analytical capabilities in state public utility commissions and improve access to training and expertise for small and municipal utilities.** Federal support should be provided to states and small utilities to enable them to better manage the increasing complexities in the electricity system, such as integrating variable energy resources; incorporating energy efficiency, demand response (DR), and storage into planning; developing competencies in various technologies; and making investment and security decisions within uncertain parameters. These issues are highly technical and require a new knowledge base and skillset often within the domain of computer sciences, economics, and cybernetics. At the same time, these entities are dealing with the workforce issues of outside recruitment or retirement across the electricity industry, which are referenced in the QER 1.2. DOE should build and cultivate much-needed analytical capacity at the state level over a limited period of time by allocating funding to state public utility commissions to allow them to hire new or train existing analysts with more sophisticated and advanced skills and build institutional knowledge. Eligibility for state and local funding should be contingent upon demonstration of consideration for integrated system planning, which is outlined in Chapter VII (*A 21st-Century Electricity System: Conclusions and Recommendations*). DOE should support these analysts through an online interactive education and training platform with access to nationally recognized experts. This platform would also be available and tailored to the needs of small utilities. On a national scale, these actions will serve to sustain system reliability and security and bolster resilience.

- **Create a Center for Advanced Electric Power System Economics**. DOE should provide 2 years of seed funding for the formation of a center designed to provide social science advice and economic analysis on an increasingly transactive and dynamic 21st-century electricity system. The center should be modeled after the National Bureau of Economic Research and be managed by a university consortium. The consortium will establish and maintain a network of experts in economics, the social sciences, and the electricity system; these experts should be from academia, industry, nonprofit institutions, and the National Laboratories. The center will develop new methods where appropriate, serve as advisor and consultant to stakeholders preparing germane analyses, and foster the advancement of students and professionals who are developing expertise in these disciplines. The focus of the center will include power systems evaluation (e.g., valuation, benefit-cost, and competition analysis).

Inform Electricity System Governance in a Rapidly Changing Environment. The rapid rate of change in the electricity sector today often exceeds the ability of institutions and governance structures to respond in a manner sufficient to meet critical national goals and objectives. This is particularly true in the resolution of jurisdictional disputes over responsible price formation and valuation. Clarification and harmonization of roles and responsibilities for developing pricing can reduce market uncertainty, facilitate the achievement of policy goals, and reduce costs to ratepayers.

- **Establish a Federal Advisory Committee on Alignment of Responsibilities for Rates and Resource Adequacy.** DOE, in collaboration with the National Association of Regulatory Utility Commissioners, should convene a Federal advisory committee that reports to the Secretary or the Secretary's designee to examine potential jurisdictional concerns and issues associated with harmonizing wholesale and retail rates and tariffs. This advisory committee will evaluate and make recommendations (where appropriate) on the way in which the organized markets reflect state policy; pricing mechanisms for maintaining resource adequacy; state and Federal roles in pricing and operation of DER, storage, and microgrids; the role of aggregators; and mechanisms for implementing consumer protection across the various markets and jurisdictions. The advisory committee will represent a broad cross-section of industry and stakeholders. An annual report will be prepared by this advisory committee for the Secretary that identifies the impact of governance issues and recommends solutions.

In the remainder of this summary, we highlight a few recommendations from a much more extensive set in the full report.

Maximize Economic Value and Consumer Equity

Tailor and Increase Tools and Resources for States and Utilities to Effectively Address Transitions Underway in the Electricity System. States and electric utilities are responsible for making critical decisions regarding how to improve the reliability, affordability, and sustainability of the electric grid, and officials from state agencies and utilities provided comments as part of the QER stakeholder process on the Federal role in informing these decisions. Technical assistance, improved regional consideration in program offerings, and new analysis for decision making will allow the Federal Government to respond to the needs of states and utilities in ensuring consumer value and equity in the electricity system of the 21st century. Recommendations include the following:

- Improve energy management and DR in buildings and industry
- Increase Federal support for state efforts to quantitatively value and incorporate energy efficiency, DR, distributed storage, and distributed generation into resource planning.

Expand Federal and State Financial Assistance to Ensure Electricity Access for Low-Income and Underserved Americans. Analysis indicates that electricity costs represent a disproportionate share of total income for low-income Americans. Increased funding for proven, state-administered programs and enhanced data and tools for targeting assistance can reduce this "electricity burden." Ensuring that the costs of the rapid transition of the electricity system are not disproportionately borne by low-income Americans is a top priority; low-income Americans should also be able to share in the benefits from an electricity system transition. Recommendations include the following:

- Encourage public-private partnerships to underwrite and support clean energy access for low- and moderate-income households
- Provide assistance to address rural, islanded, and tribal community electricity needs.

Increase Electricity Access and Improve Electricity-Related Economic Development on Tribal Lands. The interdependencies of electricity access, health, economic wellbeing, and quality of life underscore the importance of universal access to electricity. While recent data on electricity access on tribal lands is limited, there are still areas that lack adequate access to electricity despite the Nation's commitment to full electrification dating back to the Rural Electrification Act of 1936. More recent anecdotal evidence suggests that the problem broadly persists. It is a moral imperative that the Federal Government support tribal leadership and utility authorities to provide basic electricity service for the tens of thousands of Native Americans who currently lack access to electricity and to foster the associated economic development on tribal lands. Federal agencies should also support renewable energy acceleration and economic development opportunities through renewable energy incentives, workforce development, financing program improvements, and improved consultation with tribes. Recommendations include the following:

- Support the achievement of full tribal land electrification
- Support advanced technology acceleration and economic development opportunities for tribal lands.

Strengthen Rural Electricity and Broadband Infrastructure. The Federal Government has historically supported the expansion of access to affordable electricity and communications services in rural America, with major initiatives continuing today mainly through the Department of Agriculture. The lack of access to broadband in rural areas means that these consumers lack access to DR technologies, such as smart meters, smart thermostats, and other technologies that can reduce pollution, help consumers save electricity, improve overall grid resilience and reliability, and enhance economic development. Broadband expansion into these regions would significantly advance grid modernization goals, while providing significant communications, connectivity, and educational benefits to numerous regions of the country. Supporting broadband access in sparsely populated rural areas, many of which are low-income areas, is not, however, profitable for the private sector. Federal support would help enhance security, environmental, and economic development goals. Recommendations include the following:

- Leverage utility broadband build-out to expand public broadband access in rural areas
- Increase opportunities for small and rural utilities to utilize the Department of Agriculture's electricity financing programs.

Enable a Clean Electricity Future

Transform the Electricity System through Leadership in National Clean Electricity Technology Innovation. Private-sector investment in clean energy technology faces many barriers. For example, prices do not reflect the costs and benefits of clean energy, investments are made in a highly regulated environment, and there are high capital costs and the long time horizons for research and development (R&D) and capital stock turnover in comparison to many other sectors (e.g., information technology). Increased investments in electricity technology innovation is essential for transformation of the electricity system. Federal investments have a history of success and have been leveraged by the private sector to create significant economic value; case studies on nuclear energy, shale gas, and solar photovoltaic, among many other electricity-related technologies, demonstrate the instrumental role of Federal investment in early-stage R&D. Recommendations include the following:

- Significantly increase Federal investment in clean electricity research, development, and demonstration
- Implement Regional Clean Energy Innovation Partnerships.

Address Challenges to Large-Scale, Centralized Clean Generation. Regardless of the energy source, there are a number of challenges to deploying large, centralized power-generation facilities. Lower electricity prices, largely related to low-cost natural gas, are reducing the economic viability of other clean generation resources, especially nuclear energy. Nuclear power currently provides 60 percent of zero-carbon generation in the United States. Hydropower is one of the oldest and most established forms of electricity generation, contributing 6 percent of the electricity generated in the United States in 2015 and 19 percent of zero-carbon generation. Non-hydropower renewables—including wind, solar, geothermal, and biomass—accounted for about 7 percent of electricity generated in the United States in 2015. Each of these technologies faces a range of siting constraints, licensing and permitting processes, or environmental concerns, which can be broad and extensive; this can make new, large-scale deployments difficult—in some cases, taking a decade or more to build. A combination of Federal coordination, licensing support, analysis of financing opportunities, and research, development, and demonstration can help address these barriers. Recommendations include the following:

- Increase funding for the life-extension R&D program to ensure maximum benefits from existing nuclear generation
- Increase support for advanced nuclear technology licensing at the Nuclear Regulatory Commission
- Develop environmental mitigation technologies for hydropower.

Address Significant Energy-Water Nexus Issues Affecting—and Affected by—the Electricity Sector. Electricity systems and water systems are in many cases interconnected. Water is a critical requirement for many electricity-generation technologies. Two-thirds of total U.S. electricity generation—including many coal, natural gas, nuclear, concentrated solar power, and geothermal plants—requires water for cooling. In addition, carbon capture, utilization, and storage (CCUS) technologies have significant water demands. Electricity is also required for water and wastewater conveyance, treatment, and distribution. From a full-system perspective, the joint reliance of electricity and water systems can create vulnerabilities (e.g., drought impacts on thermoelectric generation and hydropower), but it can also create opportunities for each system to benefit from well-designed integration. Such challenges and opportunities can be addressed through improved policy integration; data collection; modeling; analysis; research, development, demonstration, and deployment; and engagement with stakeholders. Recommendations include the following:

- Launch an electricity-related Energy-Water Nexus Policy Partnership with Federal, state, and local partners.

Provide Federal Incentives for a Range of Electricity-Related Technologies and Systems. A package of tax incentives targeted at specific market segments can support an all-of-the-above energy strategy by helping to reduce the costs of deploying and using innovative, commercially available energy technologies. The economies of scale and "learning by doing" promoted by such deployments support continued technology cost reductions and greater market competition. Recommendations include the following:

- Expand the time frame and the total capacity allowed under the Production Tax Credit for nuclear generation
- Provide tax credits for CCUS
- Increase power purchasing authorities for the Federal Government from 10 to 20 years.

Address a Range of Power Plant Siting Issues. The land-use requirements for different types of power generation reflect significant differences between the various types of infrastructure and their operational requirements. Recommendations include the following:

- Evaluate and develop generation-siting best practices
- Modernize electricity transmission permitting procedures.

Grid Operations and Planning for Electricity System Reliability, Security, and Resilience

Support Industry, State, Local, and Federal Efforts to Enhance Grid Security and Resilience. Some types of extreme weather events are projected to increase in frequency and intensity due to climate change. Cyber threats to the electricity system are increasing in sophistication, magnitude, and frequency. Physical threats remain a concern for industry. These challenges could be mitigated through a combination of cost-benefit analyses, standards, and collaboration across industry, state, local, and Federal stakeholders. The following recommendations build upon and extend current initiatives, such as DOE's Grid Modernization Initiative and Partnership for Energy Sector Climate Resilience. Recommendations include the following:

- Develop uniform methods for cost-benefit analysis of security and resilience investments for the electricity system
- Provide incentives for energy storage
- Support grants for small utilities facing cyber, physical, and climate threats
- Support mutual assistance for recovering from disruptions caused by cyber threats

- Support the timely development of standards for grid-connected devices
- Require states to consider the value of DER, funding for public purpose programs, energy and efficiency resource standards, and emerging risks in integrated resource or reliability planning under the Public Utility Regulatory Policies Act.

Improve Data for Grid Security and Resilience. As the Nation increasingly relies on electricity to power the economy and support consumer options and choices, the consequences of electricity outages are rising. The United States currently lacks sufficient data on all-hazard events and losses. Such data would help utility regulators, planners, and communities analyze and prioritize security and resilience investments. Recommendations include the following:

- Enhance coordination between Energy Sector Information Sharing and Analysis Centers and the intelligence communities to synthesize threat analysis and disseminate it to industry in a timely and useful manner.

Encourage Cost-Effective Use of Advanced Technologies that Improve Transmission Operations. Permitting and planning are necessary but complex processes that can slow transmission development and increase costs. Other barriers restrain the use of new technologies that can increase transmission system capacity utilization and improve reliability and security, as well as other planning priorities. Recommendations include the following:

- Promote deployment of advanced technologies for new and existing transmission.

Improve the Energy Information Administration's (EIA's) Electricity Data, Modeling, and Analysis Capabilities. EIA provides all levels of stakeholders—government, companies, and customers—with data to inform the evaluation and development of policies that affect the electricity grid. More timely and publicly accessible data on how system operations are changing and how efficiency and renewable energy are specifically affecting them would facilitate the development of Federal and state policies and investments needed to ensure the reliability, resilience, and security of the grid. Substantially improved electricity transmission data and related analyses by EIA would support significant improvements in the effectiveness of a broad range of government policies and programs, including market design and transmission planning. Recommendations include the following:

- Expand economic modeling capability for electricity
- Expand EIA data collection on energy end use
- Support EIA's collection of additional data on electricity and water flow for water and wastewater.

Electricity Workforce of the 21st Century: Changing Needs and New Opportunities

Support the Electricity Sector Workforce. The electricity sector is undergoing a number of significant shifts in structure, energy sources, and applications as the industry modernizes and evolves. The full potential of these shifts, however, will only be realized if the electricity sector workforce appropriately adapts and grows to meet the needs of the 21st-century electricity system. The Federal Government has an interest in the development of this workforce. Recommendations include the following:

- Support cyber-physical systems curriculum, training, and education for grid modernization and cybersecurity
- Support Federal and regional approaches to electricity-workforce development and transition assistance.

Meet Federal Commitments to Communities Affected by the Transformation of the Electricity Sector. To achieve the transition to the electricity sector of the 21st century smoothly, quickly, and fairly, the Federal Government should offer a synthesized package of incentives that addresses the needs of the most important stakeholders both within and outside of the electricity sector. Many of these needs are addressed through other recommendations on this list, including incentives to reduce the cost of flexible and clean assets, encourage the deployment of new and improved technologies throughout the electricity supply chain, and train workers for 21st-century electricity jobs. Recognizing that the shift to the 21st-century electricity system can impact communities dependent on 20th-century resources, the following recommendations provide transition assistance for communities affected by the multi-decadal decline in coal production. Recommendations include the following:

- Meet the Federal commitment to appropriate sufficient funding to accomplish the mission of the Abandoned Mine Lands Fund.

Enhancing Electricity Integration in North America

Increase North American Cooperation on Electric Grid and Clean Energy Issues. Electric reliability cooperation is needed to strengthen the security and resilience of an increasingly integrated cross-border electricity grid. A clear understanding of the regulatory requirements at the Federal and state levels for the permitting of cross-border transmission facilities, sharing of best practices, and exploration of potential future cooperation on grid security issues will limit uncertainties and improve policy coordination at the multilateral and international levels. Recommendations include the following:

- Increase U.S. and Mexican cooperation on reliability
- Advance North American grid security
- Modernize international cross-border transmission permitting processes.

Conclusion

The electricity sector has been, and will continue to be, an indispensable tool to enable the United States to meet its linked national goals. Thanks to technology innovation and more than a century of development, the U.S. electricity system is already an extraordinary national asset. It has supported significant progress towards economic prosperity, equity, environmental responsibility, and security and resilience. QER 1.2 identifies many approaches that can build on this success to advance—and accelerate—the electricity system's role in meeting these goals.

Chapter I

TRANSFORMING THE NATION’S ELECTRICITY SYSTEM: THE SECOND INSTALLMENT OF THE QUADRENNIAL ENERGY REVIEW

This chapter explores the context surrounding the transformation of the Nation’s electricity system, including the critical role that electricity plays in the Nation’s infrastructure, opportunities that the electricity system and widespread electrification and digitization have created to enhance economic value, the imperative to reduce carbon emissions to mitigate climate change, new management challenges for grid operators that have arisen due to recent trends in electricity generation and demand, and the electricity system as a national security concern. Though the jurisdictional structure of the electricity system is complex, the Federal Government will play a major role in managing the challenges and taking advantage of the opportunities that the 21st-century grid presents.

Conceptual Framework for Electricity Sector Policy Considerations

Thomas Edison's observation that electricity had the potential to "reorganize the life of the world" was prescient. Electricity is now foundational to modern life and has enabled enormous value creation over the last 130 years—from Edison's Pearl Street Station, to Insull's grid, to the electrification of rural America, to the build-out of the Nation's grid after World War II, to today's vast and complex interconnected power grid.[a]

[a] Orison Swett Marden, ed., *Little Visits with Great Americans: Or, Success, Ideals, and How to Attain Them* (New York, NY: Success Company, 1903), digitized December 9, 2008, 30, https://books.google.com/books?id=7do8AAAAYAAJ.

Electricity is essential for the Nation's consumers, commercial and industrial sectors, social fabric, and national defense. The electricity sector is, however, confronting a complex set of changes and challenges, including aging infrastructure; a changing generation mix; growing penetration of variable generation; low and, in some cases, negative load growth; climate change; increased physical and cybersecurity risks; and, in some regions, widespread adoption of distributed energy resources (DER). How these changes are managed is critical and could fundamentally transform the electricity system's structure, operations, customer base, and jurisdictional framework. *The electricity system is the enabler for accomplishing three key national goals: improving the economy, protecting the environment, and increasing national security. As a critical and essential national asset, it is a strategic imperative to protect and enhance the value of the electricity system through modernization and transformation.*

This chapter explores the context surrounding the transformation of the Nation's electricity system, including the critical role that electricity plays in the Nation's infrastructure, opportunities that the electricity system and widespread electrification and digitization have created to enhance economic value, the imperative to reduce carbon emissions to mitigate climate change, new management challenges for grid operators that have arisen due to recent trends in electricity generation and demand, and the national security implications of grid dependency. Though the jurisdictional structure of the electricity system is complex, the Federal Government will play a major role in managing the challenges and taking advantage of the opportunities that the 21st-century grid presents.

The U.S. Electricity System: Operating and Economic Statistics

In the United States, there are around 7,700 operating power plants[b] that generate electricity from a variety of primary energy sources; 707,000 miles of high-voltage transmission lines;[c] more than 1 million rooftop solar installations;[d] 55,800 substations;[e] 6.5 million miles of local distribution lines;[f] and 3,354 distribution utilities[g] delivering electricity to 148.6 million customers.[h, i] The total amount of money paid by end users for electricity in 2015 was about $400 billion.[j] This drives an $18.6 trillion U.S. gross domestic product and significantly influences global economic activity totaling roughly $80 trillion.[k]

[b] "Frequently Asked Questions: How Many Power Plants Are There in the United States?" Energy Information Administration, accessed October 19, 2016, http://www.eia.gov/tools/faqs/faq.cfm?id=65&t=2.

[c] Ellen Flynn Giles and Kathy L. Brown, eds., *2015 UDI Directory of Electric Power Producers and Distributors: 123rd Edition of the Electrical World Directory* (New York, NY: Platts, 2014), vi–vii, https://www.platts.com/im.platts.content/downloads/udi/eppd/eppddir.pdf.

[d] Julia Pyper, "The US Solar Market Is Now 1 Million Installations Strong," Greentech Media, April 21, 2016, https://www.greentechmedia.com/articles/read/The-U.S.-Solar-Market-Now-One-Million-Installations-Strong.

[e] "Electric Substations," Platts, generated March 6, 2009, http://www.platts.com/IM.Platts.Content/ProductsServices/Products/gismetadata/substatn.pdf.

[f] Ellen Flynn Giles and Kathy L. Brown, eds., *2015 UDI Directory of Electric Power Producers and Distributors: 123rd Edition of the Electrical World Directory* (New York, NY: Platts, 2014), vi–vii, https://www.platts.com/im.platts.content/downloads/udi/eppd/eppddir.pdf.

[g] Ellen Flynn Giles and Kathy L. Brown, eds., *2015 UDI Directory of Electric Power Producers and Distributors: 123rd Edition of the Electrical World Directory* (New York, NY: Platts, 2014), vi, https://www.platts.com/im.platts.content/downloads/udi/eppd/eppddir.pdf.

[h] A "customer" is defined as an entity that is consuming electricity at one electric meter. Thus, a customer may be a large factory, a commercial establishment, or a residence. A rough rule of thumb is that each residential electric meter serves 2.5 people. Of the Nation's 147 million customers, 13 million now purchase electricity from non-utility retail service providers, comprising 20 percent of all U.S. retail electric sales (megawatt-hours) and delivered mostly by investor-owned distribution utilities, in the 19 states and District of Columbia that allow retail competition.

[i] Energy Information Administration (EIA), *Electric Power Annual 2015* (Washington, DC: EIA, 2016), Table 2.1, http://www.eia.gov/electricity/annual/.

[j] "Electric Power Sales, Revenue, and Energy Efficiency Form EIA-861 Detailed Data Files," Energy Information Administration, last modified October 6, 2016, https://www.eia.gov/electricity/data/eia861/.

[k] International Monetary Fund, *World Economic Outlook Database, Entire Dataset, by Country Groups, GDP, Current Prices* (International Monetary Fund, April 2016), https://www.imf.org/external/pubs/ft/weo/2016/01/weodata/download.aspx.

Electricity from Generation to End Use

The second installment of the Quadrennial Energy Review (QER 1.2) analyzes trends and issues confronting the Nation's electricity sector, examining the entire electricity supply chain from generation to end use. It builds on analysis and recommendations in the first installment of the QER (QER 1.1), which included electricity as part of a broader examination of energy transmission, distribution, and storage infrastructures.

QER 1.1 identified key trends that suggested the need for greater analysis to inform a set of recommendations that will help set a pathway for modernized electricity systems capable of meeting the Nation's needs in a 21st-century economy. Trends for QER 1.2 include the changing generation mix; low load growth; increasing vulnerabilities to severe weather/climate change; the proliferation of new technologies, services, and market entrants; increasing consumer choice; emerging cyber/physical threats; aging infrastructure and workforce; and the growing interdependence of regulatory jurisdictions. Recommendations focus on research and development (R&D), storage, transmission planning, state financial assistance, valuation of new services and technologies, and interoperability of technologies. Added to this mix is the growing and near-complete dependence of other critical infrastructures on electricity, increasing consumer choice options for distributed generation (DG), and new high-value information/communications industries and businesses.

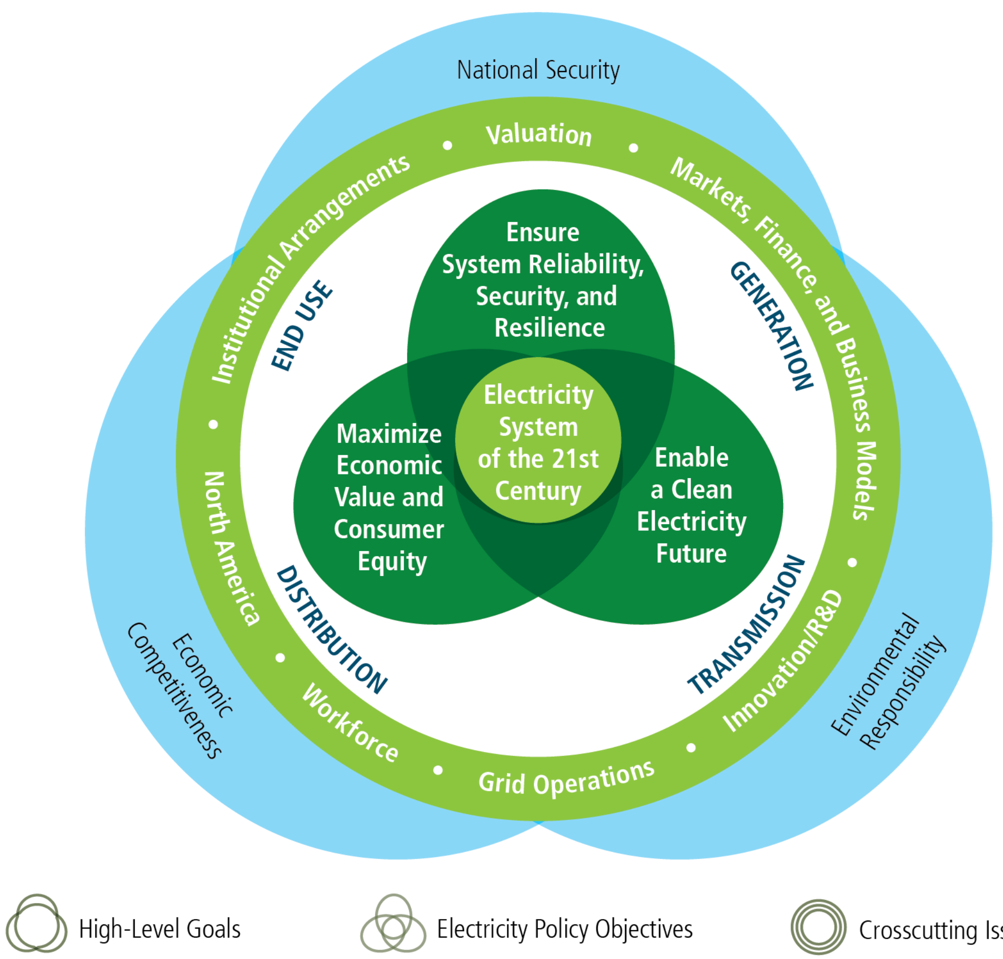
Underlying this is the need for ever-greater system security, driven by growing cyber and physical threats, expanding interconnectedness, and the increase in extreme weather events because of climate change. This evolution is and will be "bumpy"—the costs/benefits and investment requirements needed to accommodate deployment of new technologies and grid modernization are challenging the electricity industry and regulators alike to understand the scale, scope, and operating changes required as the grid gets smarter, with the Supreme Court now in the position of resolving key jurisdictional issues.

National Goals for a 21st-Century Electricity Sector

While respecting state, regional, and tribal prerogatives, QER 1.2 supports the development of a consistent Federal strategy to enable a 21st-century electricity system.

QER 1.2 will analyze these issues in the context of three overarching national goals to (1) enhance economic competitiveness, (2) promote environmental responsibility, and (3) provide for the Nation's security. The overall structure of the study and its recommendations is depicted in Figure 1-1. Security, economy, and environmental responsibility are all interconnected and crosscutting goals, and transformation of the electricity sector must address all three of these national goals.

Figure 1-1. Goals, Objectives, and Organization of QER 1.2



The organization of QER 1.2 reflects the comprehensive set of interactions and overlapping goals and objectives for enabling the electricity system of the 21st century.

Economic Competitiveness and the Electricity Sector

A key driver for U.S. economic competitiveness has been the supply and delivery of electricity that is affordable, accessible, and reliable. The reliability of electricity directly affects the efficiency of production processes, enabling the efficient and cost-effective coordination of economic activity without disruption. With some of the lowest electricity prices in the developed world,[1] the U.S. electricity sector supports economic competitiveness of U.S. goods and services in both domestic and global markets. Energy infrastructures should enable new architectures to stimulate energy efficiency, new economic transactions, and new consumer services. The modernization of the U.S. electricity system—through the growth of clean, smart, and resilient systems and services—will create demand for an enhanced workforce to enable this transition.

Environmental Responsibility and the Electricity Sector

The electricity system should be developed and managed in an environmentally responsible manner by, in part, addressing the central challenge of climate change and mitigating its impacts. The national objective of "deep decarbonization" by mid-century will challenge the electricity sector in many ways. Achieving this key objective will improve the health of Americans and the environment of the country, both of which are positive contributions to matters of economic competitiveness and national security. At the same time, policymakers, investors, and industry must consider and address the longstanding needs of the vulnerable segments of the population and appropriately address these issues as the electricity system is transformed.

Other critical environmental concerns include climate adaptation; further reductions in conventional pollutants; adequately analyzing, addressing, and managing the energy-water nexus; reduction of land-use and other impacts of electricity generation, transmission, and distribution; and infrastructure lifecycle management.

National Security and the Electricity Sector

Electricity is essential for supporting and sustaining industrial output, government, emergency services, interdependent critical infrastructures, and the U.S. national security apparatus. These critical infrastructures include physical and information infrastructures that are required for communications, transportation, and almost every other element of economic and social activity. Even though it is essential to the economy, lifeline networks, emergencies, and the national security apparatus, electricity—unlike oil—cannot be stored at scale. The electricity sector should be considered and included in the development of national security doctrine, policies, and plans. A continuous effort to maintain reliable electricity supplies in the face of a growing number of potential threats (cyber attacks, electromagnetic pulses, terrorist attacks, and natural disasters) is required for the national defense, continuity of government, economic prosperity, and quality of life nationwide.

Turning National Goals into Actionable Priorities for Electricity System Transformation: Integrated Objectives for QER 1.2

The analysis conducted for the QER 1.2 identified three major integrated objectives that address the needs and challenges to enable the electricity sector of the 21st century. These objectives—maximizing economic value and consumer equity; building a clean electricity future; and ensuring electricity system reliability, security, and resilience—are discussed in detail in several QER 1.2 chapters.

Maximize Economic Value and Consumer Equity

The United States has relatively low-cost electricity and a highly reliable electricity delivery system (transmission and distribution). Power is generated from both central and onsite sources, such as distributed solar and combined heat and power installations. The sum of these capabilities is a platform on which a vibrant, globally competitive economy thrives.

Although electricity is an energy carrier and not a primary energy source, electricity exhibits the interchangeable characteristics of a commodity—a kilowatt-hour generated by any resource can be easily used by any type of customer. Electricity is unique as a commodity, however, because it requires real-time balancing across multiple spatial and temporal scales (location-specific pumped hydro is an exception). This requirement for immediate matching of demand and supply can result in prices that vary significantly from minute to minute or season to season.

Because many aspects of the electricity system—including R&D in new technologies, emissions mitigation, and grid reliability—are public goods and will be underprovided by private industry, the U.S. Government has played a critical role in developing a clean electricity economy and making sure that the electricity supply has continued to be available, affordable, and reliable to U.S. industry and citizens.

Historically, electricity consumption and gross domestic product (GDP) have tended to move in tandem—electricity consumption has tended to rise during economic expansions and fall during recessions (between 1950 and 2013, there was a 66 percent correlation between GDP and electricity use).[2] Over the last several decades, however, growth in electricity use has been lower than growth in GDP. This is due in part to a restructuring of the economy; also, across all economic sectors, energy efficiency has been remarkably successful over several decades in helping control costs and improving performance and productivity.

Enable a Clean Electricity Future

Much of the U.S. electricity system was built out before the United States had a significant complement of modern environmental laws and without the range of technologies that have been developed and deployed to reduce air emissions and other environmental impacts of power generation, transmission, and use. The U.S. electricity system is deeply linked to environmental quality; environmental policies must be carefully and purposefully balanced with other objectives. In addressing associated issues, the United States should build on past successes in reducing the public health and environmental impacts from the electricity system based on a mutually reinforcing cycle of technological improvements and policies.

The electricity system today is the largest source of U.S. greenhouse gas (GHG) emissions, particulate matter, and acid precipitation; one of the largest users of fresh water; a major cause of land and ecosystems impacts; and the principal source of radioactive waste. Addressing these environmental concerns may require a range of new policies, acceleration of technology innovation, and additional incentives for the deployment of new technologies.

Equity is a particular concern when addressing pollution from electricity generation, transmission, and distribution. Power plants and other electricity-related infrastructure are often located in or near low-income and minority communities, creating disproportionate impacts on these populations. Also, climate change impacts—such as heat waves, degraded air, and extreme weather—will add additional stressors that will disproportionately affect low-income communities.

Ensure Electricity System Reliability, Security, and Resilience

The United States faces complicated and evolving challenges that affect the reliability, security, and resilience of the electricity system. Operators of the grid must simultaneously meet existing performance standards and system requirements, as well as address a rapidly evolving system. These changes stress the public and private institutions created to support a legacy paradigm established over the last 100 years or more. The threat environment is also changing—decision makers must make the case for investments that mitigate catastrophic, high-impact, low-probability events.[3] Also, not all hazards can be prevented; improvements are needed in technologies and processes by which the grid can fail elegantly, recover quickly, and become more resilient over time.

In addition, the electricity system is vital to the Nation's increasingly interconnected, digitally dependent economy and society. Without access to reliable electricity, significant economic value and all electricity-enabled critical infrastructures are put at risk. These include national security and homeland defense networks that depend on electricity to help ensure the safety and prosperity of the American people.

Addressing Climate Change Is an Environmental, Economic, and National Security Imperative

The accumulated evidence of decades of climate science clearly shows that humans are impacting the climate system in new and damaging ways, primarily through the emissions of greenhouse gases (GHGs). Since the widespread adoption of fossil fuels during the Industrial Revolution, human activities have been emitting carbon dioxide (CO_2) faster than the Earth has been removing and storing it. The 17 warmest years on record have occurred in the last 18 years,[l] with 2015 being the warmest year on record; 2016 will likely set yet another record.[m, n]

Humans experience the climate system not as global, annual averages, but through the climate effects on local weather. Localized impacts can make dry places dryer; wet places wetter; and areas exposed to tropical storms more at risk for high winds, heavy rain, and flooding. What were once rare extreme heat events are already becoming commonplace. Sea-level rise and coastal erosion, coupled with more powerful storms, have destroyed infrastructure and damaged tourism along the East Coast of the United States. Flooding of inland rivers has damaged midwestern and northeastern cities. Also, the Arctic, which has been warming at more than twice the rate of lower latitudes,[o] is experiencing infrastructure damage from thawing permafrost; shrinking sea ice (with impacts on coastal erosion and subsistence hunting); and a longer, more destructive wildfire season.

The electricity supply system is a major contributor to U.S. GHG emissions and creates other stresses on the environment as well. Minimizing impacts on climate, air, water, land, ecosystems, and worker and public safety must be priorities for the electricity system, including power plant construction, operation, and decommissioning, as well as transmission and distribution of electricity, no matter its source.

The long residence time of CO_2 in the atmosphere establishes an urgent need to act to mitigate the impacts of climate change; even if all CO_2 emissions stopped immediately, the global mean surface temperature would continue to rise and the associated impacts would be felt around the globe for decades to come. In the electric sector, increasing temperatures can increase demand for cooling, and warmer water supplies can challenge water-cooled electric generation facilities. Resilience and adaptation are the means by which the United States can reduce these harms, and the electricity system will need to become more resilient and adapt to a changing climate.

[l] LuAnn Dahlman, "Climate Change: Global Temperature," National Oceanic and Atmospheric Administration, January 1, 2015, https://www.climate.gov/news-features/understanding-climate/climate-change-global-temperature.

[m] LuAnn Dahlman, "Climate Change: Global Temperature," National Oceanic and Atmospheric Administration, January 1, 2015, https://www.climate.gov/news-features/understanding-climate/climate-change-global-temperature.

[n] Patrick Lynch, "2016 Climate Trends Continue to Break Records," National Aeronautics and Space Administration, July 19, 2016, http://www.nasa.gov/feature/goddard/2016/climate-trends-continue-to-break-records.

[o] J. Overland, E. Hanna, I. Hanssen-Bauer, S.-J. Kim, J. E. Walsh, M. Wang, U. S. Bhatt, and R. L. Thoman, "Surface Air Temperature," in *Arctic Report Card: Update for 2016, Persistent Warming Trend and Loss of Sea Ice Are Triggering Extensive Arctic Changes*, edited by J. Richter-Menge, J. E. Overland, and J. T. Mathis (National Oceanic and Atmospheric Administration, Arctic Program, 2016), http://www.arctic.noaa.gov/Report-Card/Report-Card-2016/ArtMID/5022/ArticleID/271/Surface-Air-Temperature.

Crosscutting Issues Important to Achieving National Goals and 21st-Century Grid Modernization

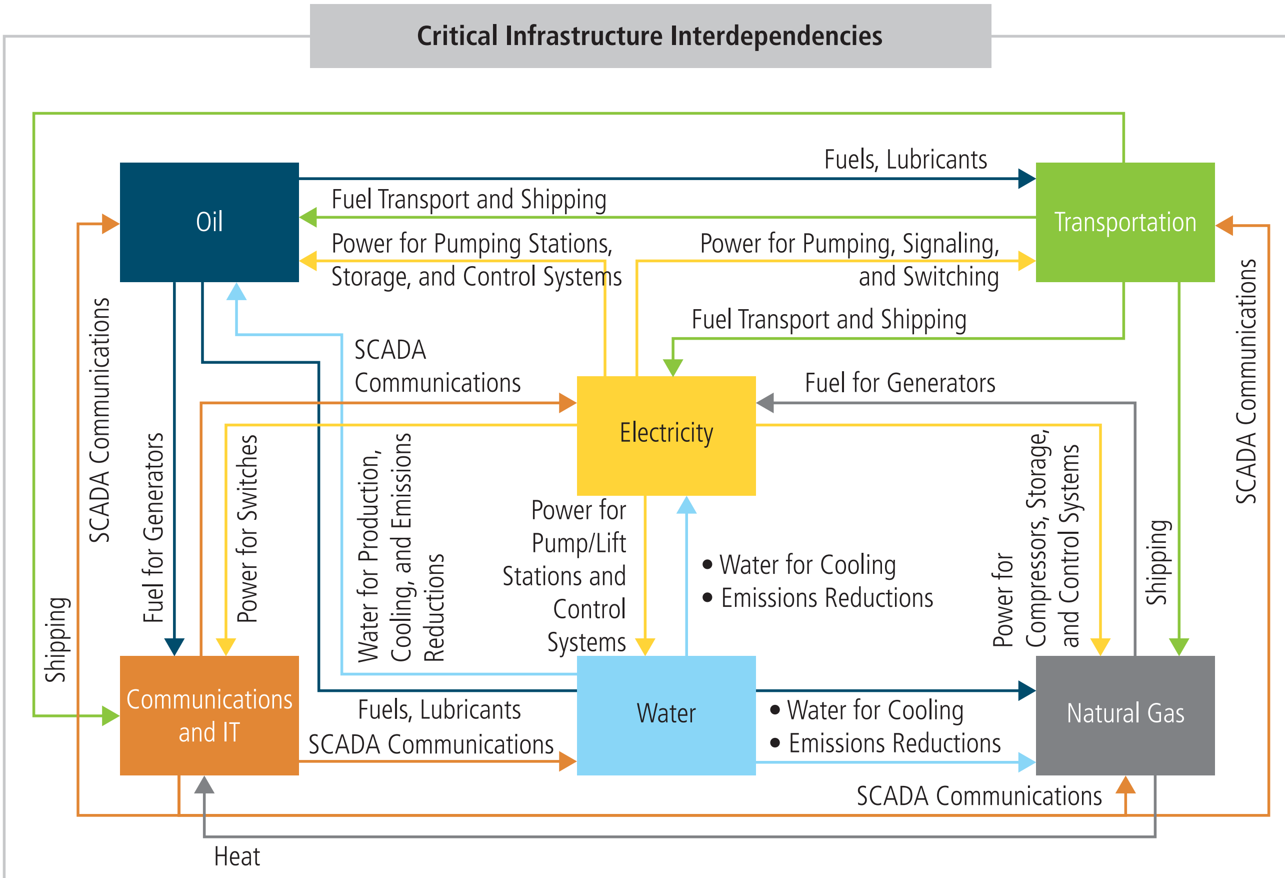
Grid modernization requires actionable policies, practices, and investments that help ensure system security, reliability, and resilience, and a clean electricity future. These objectives have overlapping and crosscutting considerations that must be recognized and managed. The crosscutting issues examined in QER 1.2 include valuation; markets, finance, and business models; innovation and R&D; grid operations; the electricity sector workforce; North America–wide impacts; and institutional arrangements that are foundational to the sector. Discussion of most of these complex topics is embedded into each QER 1.2 chapter.

The Nation's Critical Infrastructures Depend on Electricity

QER 1.2's examination of the electricity system from generation to end use necessarily starts with a discussion of the dependence of the Nation's critical infrastructures on electricity. Critical infrastructure dependencies and interdependencies represent the core underlying framework that supports the American economy and society. Electricity is at the center of key critical infrastructure networks that support these sectors, including transportation, oil and gas production, water, and telecommunications.

These critical networks are increasingly converging, sharing resources and synergistic interactions via common architectures (Figure 1-2). The oil and gas sectors rely heavily on electricity. Transportation is critical to power production because it enables the shipping of fuels; this sector also depends on electricity for key needs, such as power for signaling and switching, and will become even more dependent as more electric vehicles are deployed. Water systems are also critical infrastructure. Water purification, movement, and treatment currently consume roughly 4 percent of the Nation's annual electricity generation;[4] in California, this amount can be up to 20 percent of electricity generation.[5] Many water facilities lack sufficient power backup capabilities; at the same time, they meet key cooling requirements for power generation. Water availability is already a concern in many parts of the country, and climate change is expected to exacerbate this problem in certain regions of the United States.[6]

Figure 1-2. Critical Infrastructure Interdependencies[7]



Key critical infrastructure interdependencies represent the core underlying framework that supports the American economy and society. The financial services sector (not pictured) is also a critical infrastructure with interdependencies across other major sectors supporting the U.S. economy.

Acronyms: information technology (IT), supervisory control and data acquisition (SCADA).

There is also a direct and critical link between the electricity system and communications networks.[8] The Department of Homeland Security (DHS) identifies the information and communications technology (ICT) infrastructure as a critical infrastructure because it provides an "enabling function" across all other critical infrastructure sectors. ICT infrastructure is critical to each stage in the electricity supply chain and to all other critical infrastructures seen in Figure 1-2. Within the electricity sector, ICT infrastructure is increasingly important for grid management, as well as for communications with customers and various distributed assets. In addition, electricity powers ICT systems equipment; its central control and operating systems; and even its heating, ventilation, and air conditioning systems.

The financial sector is another critical infrastructure that depends on electricity (through its role in enabling telecommunications) and other communications networks. DHS's 2015 "Financial Services Sector-Specific Plan" notes, "Most of the sector's key services are provided through or conducted on information and communications technology platforms, making cybersecurity especially important to the sector. In addition, the sector faces ongoing risks associated with natural disasters, as well as the potential for physical attacks. Hurricanes, tornadoes, floods, and terrorist attacks all have the potential to cause physical disruptions that have significant impacts on Financial Services Sector operations."[9]

Natural gas and electricity interdependencies are also growing. The first half of 2016 was the first period where natural gas was the largest source of primary fuel for power generation in the United States. The increased use of natural gas for power generation introduces the potential for complications and disruptions, and it has, in fact, resulted in a futures market metric called the "spark spread" used to inform markets about the gas/electricity market relationship. The gas sector also relies on electricity in segments of the production chain, including use for field-gathering pumps, selected transmission pipelines, and gas-processing stations.

The interdependencies of key infrastructures and the essential role of electricity are illustrated by recent weather emergencies. Extremely cold weather in New Mexico in 2011 resulted in both natural gas and electricity outages; loss of electricity further reduced gas production as field-gathering pumps lost power.[10] Another example is the aftermath of Superstorm Sandy in 2012 when utilities and the public experienced massive power outages in the Northeast. Recovery crews were hampered by simultaneous failures of communications systems that are almost entirely dependent on electricity (backup systems generally provide 72–96 hours of power).

Electricity-Connected Systems and Digitization Create Significant Economic Value

The electricity system supports the increased electrification of all sectors of the U.S. economy. At the same time, almost every economic sector now relies, in varying degrees, on highly interconnected, data-driven, and electricity-dependent systems to manage operations and provide services. The evolving electricity-information nexus supports a wide range of products and services and has the potential for even greater value creation. It supports new information-driven enterprises, helps lower initial and ongoing costs, improves control of risks, saves time and effort, enhances productivity, and can create new market categories. The importance of the electricity system now and in the future—described in a recent study as the "central nervous system of a data-driven economy"—cannot be fully appreciated without a discussion about how digitization has enabled the Internet of Things (IoT).[11]

Value of the Electricity-Dependent "Internet of Things"

The IoT is defined as "sensors and actuators embedded in physical objects—from roadways to pacemakers—[that] are linked through wired and wireless networks, often using the same Internet Protocol (IP) that connects the Internet."[12] Digitization and ICT have enabled virtually instantaneous global communication. These networks and their associated devices are large and growing. According to a Federal Trade Commission report issued in January 2015, "Six years ago, for the first time, the number of 'things' connected to the [global] Internet surpassed the number of people…Experts estimate that, as of this year, there will be 25 billion connected devices, and by 2020, 50 billion."[13] The growing digitization of the U.S. economy is stunning: 89 percent of Americans have access to high-speed broadband services of 25 megabits per second for downloads and 3 megabits per second for uploads;[14] 73 percent of American households use a computer with high-speed Internet at home;[15] 95 percent of college-educated adults use the Internet; 87 percent of tax returns are e-filed;[16] and 64 percent of adults use smartphones.[17]

Not surprisingly, data-, information-, and communications-centric industries are increasing their value to the U.S. economy through digitization. According to a recent study, ICTs comprised roughly 5 percent of GDP, based on 2014 metrics,[18] and technology-driven price declines are making ICTs even more attractive for businesses. It is estimated that three areas of the economy alone—online talent platforms, big-data analytics, and the IoT—could increase GDP by as much as $2.2 trillion in 2025.[19]

The IoT is increasingly used by critical sectors of the U.S. economy. The healthcare industry, for example, is revolutionizing care operations through digital records, improving patient treatment and care by sharing patient information between hospitals. The automotive industry is pioneering electric vehicle technology for use in heavy equipment, long-haul auxiliary power units and truck stops, localized service fleets, and personal vehicles. Cities are integrating "smarter"—inherently more electricity-intensive—cars to improve passenger safety. Urban areas with greater application of IoT technology and ICT have the potential to run more efficiently and sustainably. A study by Texas A&M University found that traffic problems and congestion in the United States alone cost more than $120 billion annually[20] without considering additional effects from increased pollution, decreased work productivity, or delayed delivery effects. The ability to coordinate various urban infrastructures (e.g., transportation, buildings, and the electricity distribution system) that can apply data intelligently would help improve operational efficiency, increase safety, lower costs, and contribute to system stability.

The IoT not only affects information flows on large systems—it is also affecting how energy consumers interact and control their home environments. Advanced thermostat devices, for example, automate temperature control, while learning software embedded in the technology integrates preprogrammed settings by the user with zip code location to identify the real-time weather—two inputs that the devices use to self-adjust. This and other home technologies, such as chore automation and remotely controlled security systems, are all part of a new era in which the IoT is utilized to provide greater comfort, efficiency, security, flexibility, and savings. Recent analysis suggests that the economic value of home automation and better integration of IoT technologies could be as high as $350 billion for the U.S. market alone.[21]

All sectors that rely on information and online activity—including email, social media, and Internet-connected businesses—are supported by data centers.[22] These data centers have been called "the backbone of today's digital economy," powering businesses, communications, and online consumer services and helping to make society more productive and efficient. These centers are distributed across the country, house roughly 14 million computer servers, and provide both domestic and global services. Data centers are one of the fastest-growing sources of electricity demand. More than 3 million data centers in the United States (of all sizes) now use roughly 70 billion kilowatt-hours of electricity annually.[23] This is about 1.8 percent of total national electricity consumption,[24] which is equivalent to the generation of 25 large (500-megawatt) coal-fired power plants.[25] Table 1-1 includes information about large data centers (>20,000 square feet) that currently account for about half of total data center energy use.

Table 1-1. National Data Centers Are Electricity Dependent[26]

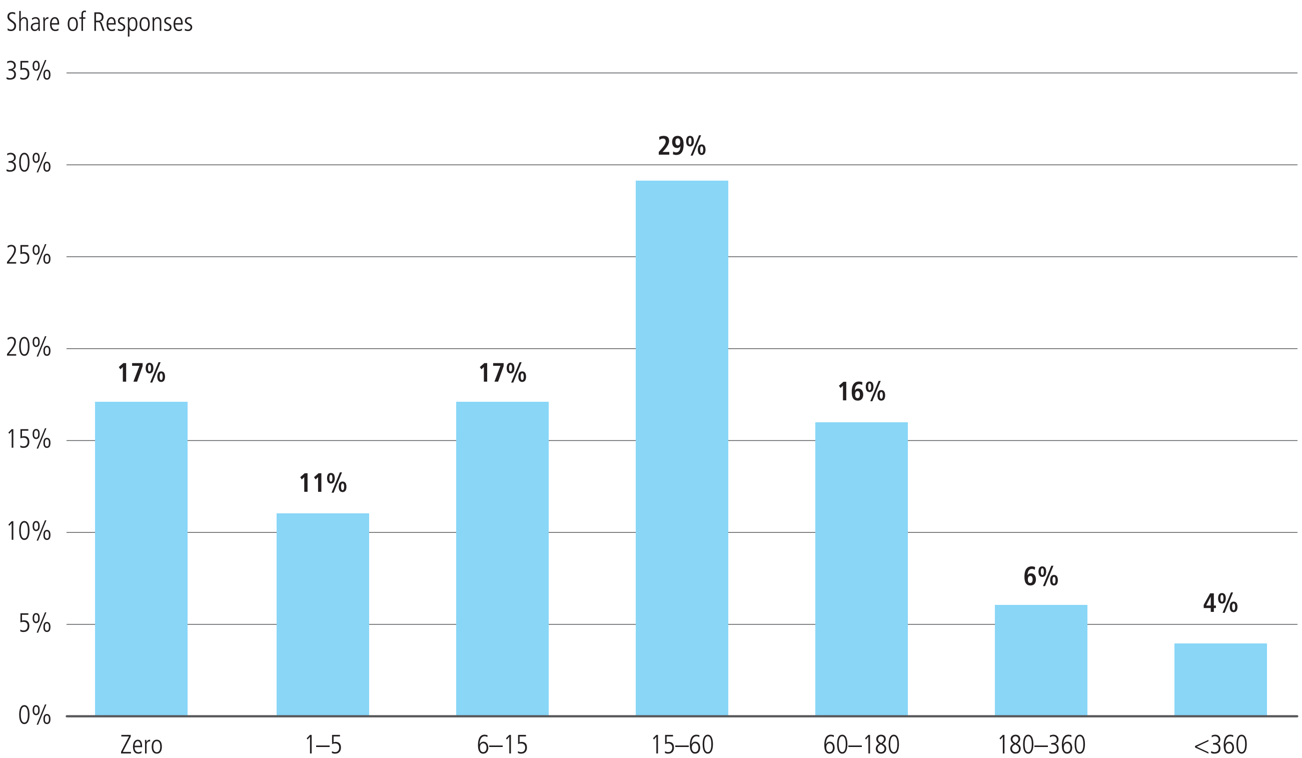
Large Data Centers (>20,000 square feet)	Nationwide
Number	9,500
Size	~320 million square feet
Server count	8 million
Power load	4 gigawatts
Storage	160 million terabytes
Energy consumption	37 billion kilowatt-hours
Backup power description (Tier III+ only)	• "Redundant and maintainable" • Fully redundant power path to all equipment (2N substation to server) • Dual utility power feed • Vendor-owned substation • More than 10 backup gensets* (diesel, natural gas) • Generally designed for 72-hour outage

*A genset is a pairing of an engine and a generator for the purpose of providing electrical power.

Commercial data centers are an important economic segment that supports much of the Internet, business activity, and e-commerce activity. These data centers also require available and reliable electricity service and invest significant money in onsite generation and backup systems to ensure power availability.

All the value from data-driven, digitized enterprises is enabled by electricity that, by current standards, is highly reliable. Nationally, the average customer experiences a little over 3 hours of electric power unavailability per year.[p, 27] But even a short disruption in power can cause serious impacts on daily life and significant economic losses for information-dependent businesses. Figure 1-3 shows the results of a large survey of data center professionals who indicated that a power outage results in immediate economic losses for 17 percent of those surveyed; 45 percent experience significant losses—from $200,000 to $1 million an hour[28]—within 15 minutes.[29]

Figure 1-3. Company Survey: Approximately How Many Minutes of Information Technology Downtime Can Occur before Business Is Negatively Impacted?[30]



When the grid goes down, data centers face significant risks as backup power does not always work. The key is to try to minimize the likelihood of grid power outages. Local power grid reliability should be a factor considered when choosing data center locations.

This loss of significant economic value from even short power outages places a very high premium on the customer as opposed to system reliability and has helped to create a growing market for backup generation to meet individual customer needs. Such backup solutions sometimes have multiple components to ensure necessary redundancy. Larger Tier III+ data centers[q] have the most extensive alternative power arrangements with redundant power systems and onsite generation; these are limited, however, by available battery storage capacity, onsite fuel storage (72–96 hours),[31] and liquid fuel resupply agreements.[32]

[p] Based on preliminary 2015 Energy Information Administration data. Information reported to the Energy Information Administration is estimated to cover approximately 70–80 percent of electricity customers.

[q] Data centers are classified by use of a four-tier system established by the Telecommunications Industry Association. Tier I is the simplest level, while Tier IV is the most stringent level, designed to host mission-critical computer systems. Tier III+ data centers are available at least 99.982 percent of the time.

In 2014, U.S. customers spent nearly $2.5 billion in capital costs to purchase and install backup alternating current generation,[33] as well as $3.2 billion for uninterruptible power supplies.[34] It is estimated that this backup generation represents roughly 200 gigawatts of generation potential[35] (in contrast to a primary installed capacity of 1,100 gigawatts). Generally, these backup systems come at a capacity cost of $200–$600 per kilowatt, but this cost profile is for a narrow set of a much wider universe of asset types that include combined heat and power, natural gas–fired units of varying sizes, fuel cells, and various storage solutions.[36]

Businesses build onsite generation because they face significant economic losses from a momentary loss of electricity or slight variation in frequency. This represents a source of lost revenue for utilities—a form of "defection"; it could also present an opportunity for utilities to provide higher-quality services than those required by the typical customer. Evidence suggests that some electricity customers are willing to pay very high prices for the incremental difference between the current measure of reliability and what they require for their business.[37]

Utility customers that install backup systems and/or onsite generation are, understandably, hedging the risks to their businesses without regard to the overall impacts on the system. This raises a range of concerns, including the possible need for new standards of reliability and associated policy parameters; the modernization of backup generation as part of modernization of the grid; possible incentives for onsite and backup power generation; and interoperability needs and standards.

An aggregate average cost for all types of installed backup power is not maintained by industry or government, and the total installed base of accessibly operational backup power nationwide is not known; there is no Federal or other database that tracks all installed assets, their scale, fuel sources, typical annual run times, cumulative emissions effects, or performance characteristics, such as how often they fail when called into operation. In addition, the Federal Government does not have any explicit government-wide backup power standards that concern operational requirements, although many states have emissions-control standards or building code requirements that impact backup generation.

Information and the Electricity Sector

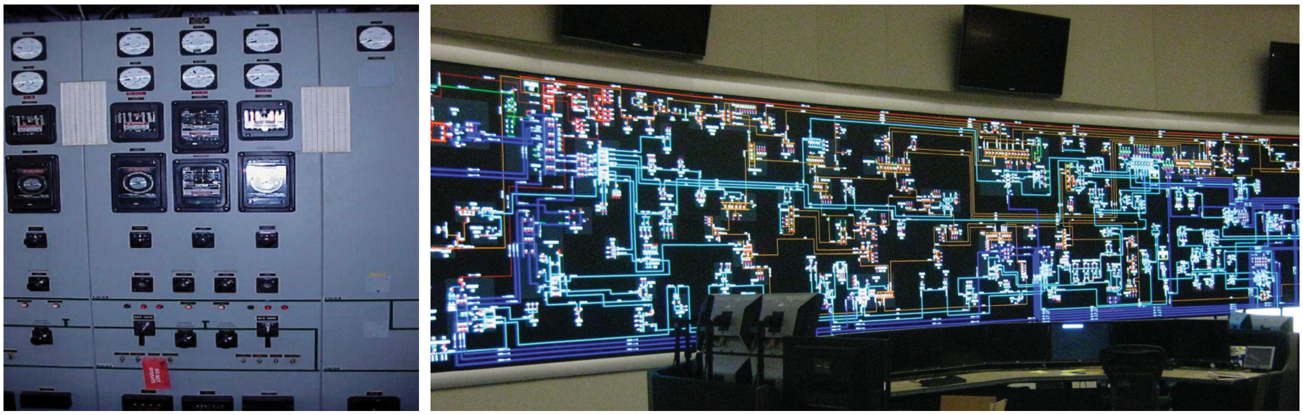
ICTs and grid control technologies for electricity systems—both large and small scale—have evolved, enabling increased interconnection and capture of economies of scale and scope. The electricity industry's early adoption of analytical and computer techniques to coordinate the generation and transmission of power has facilitated increased interconnection and inter-utility power transfers.

The use of supervisory control and data acquisition (SCADA) systems by the electricity industry has evolved over the last 90 years alongside advances in grid control technology and increases in computing and networking capabilities. Early control systems in the 1920s were installed to reduce the need for utility personnel to staff substations 24/7. Inter-utility interconnections, developed to support the war effort in World War II, demonstrated the advantages of inter-utility transactions and spurred their adoption. By the 1950s, analog computer systems were adopted to accurately monitor electricity flows. This helped enable faster and more comprehensive processing of information, which, in turn, supported improved operations, planning, and overall enterprise management.

The Great Northeast Blackout of 1965, during which 30 million people in an 80,000-square-mile area of the United States and Canada were left in the dark, underscored the need for increased information coordination to support the reliability of a dynamic grid. Institutional structures—power pools and reliability councils—were improved and enhanced after the blackout. By the late 1960s and 1970s, the advent of digital computers and the rise of microprocessors and programmable logic controllers allowed for greater control and monitoring of automated utility processes.

The development of local area networks in the 1990s enabled formerly isolated and independent SCADA systems to connect to each other. Around that same time, restructuring of the power industry and new requirements for cross-border interconnections had major impacts on electricity market structure and business models. While utilities in some regions began specializing in generation, transmission, or distribution, there were also increasing requirements for entities such as regional transmission organizations (RTOs) and independent system operators (ISOs) to monitor and gather electricity data across large regions and multiple states. Both trends required greater network management, with significant increases in data flows related to comprehensive and real-time system management, in turn making SCADA systems critically important to grid management.[38, 39] Figure 1-4 visualizes the dramatic change seen in electric utility control systems.

Figure 1-4. Electric Utility Control Systems Past to Present[40]



The image on the left depicts an early electricity control system. The image on the right shows a typical control system today.

Digitization Creates Value for the Electricity Sector

Digitization can result in improved efficiencies across a utility, allowing for optimized generation, improved workforce productivity, better visibility into customer behavior, and faster diagnostics—all of which can improve reliability and reduce costs to the utility and customer. Demand response (DR) and DG can be more fully integrated and managed by utilities through digitization, particularly through smart meters. Estimates done for the Department of Energy's (DOE's) Grid Modernization Initiative (GMI) suggest that if every U.S. retail seller of electricity deployed grid modernization technology to reduce the average planning reserve margin from 13 percent to 10 percent, it would result in $2 billion annual savings to the economy.[41] It is estimated that the digitization of utility processes—from smart grid, to workforce tools, to automation of business management processes—can boost profitability 20–30 percent.[42] Utility analytics is an emerging business growth area estimated to grow at a rate of 13.5 percent per year (from $1.8 billion in 2016 to $3.4 billion in 2021), with most growth in the United States.[43] Digitization also creates new business opportunities for utilities, such as remote building energy-management and energy efficiency services.

Information Technology–Operational Technology Integration Opportunity: Smart Metering

Smart metering has traditionally been part of the operational technology (OT) world. Automated meter reading and automated meter management solutions originated in OT and are now connected to the information technology (IT) world. Billing, on the other hand, is typically an IT solution. With integrated systems, end-to-end smart metering (meter-to-bill) bills can be based on exact readings and no longer on estimates.

Customer relationship management, also part of the IT world, plays a vital role in this scenario. With end-to-end smart metering, when a customer contacts a call center to complain about quality of service (e.g., overvoltage), the operator can contact the customer's smart meter in real time to check the historical data stored locally. In addition, new contracts can modify tariffs in the meter in near-real time.

Grid modernization will be enhanced by the integration of operational technology (OT) systems and information technology (IT) systems that, in general, serve important but distinct utility functions. OT provides the control system that executes and monitors the electricity system, aiming to protect the network, prevent electric outages or blackouts, and reduce the cost of operations. OT provides oversight and control of the physical assets that create the electricity system in real time—from generators, substations, and distribution networks to meters at the point of use. Systems that are in the realm of OT applications include distribution-management systems, energy-management systems, geographical information systems, and SCADA systems.

IT, on the other hand, is generally used for decision making on the enterprise level. This usually involves a variety of teams that must be closely synchronized to provide consistent operation, spanning areas such as business processes management, resource and asset allocation, workflow coordination, and energy and operations planning. IT software applications include energy portfolio management, customer information systems, advanced metering infrastructure (AMI), DR management, and mobile workforce management.[44]

As the electricity system becomes more digitized, connected, and complex, increased integration of IT and OT systems could enhance operational efficiency; minimize duplication of systems and processes; reduce costs; improve asset management; and integrate information and operational technology, data, and communications systems.[45]

A "Smarter Grid" Is Essential for Grid Modernization and Transformation

The "smart grid" refers to an intelligent electricity grid—one that uses digital communications technology, information systems, and automation to detect and react to local changes in usage, improve system operating efficiency, and, in turn, reduce operating costs while maintaining high system reliability.

Smart meter infrastructure, sensors, and communication-enabled devices and controls give electricity consumers and utilities new abilities to monitor electricity consumption and potentially lower usage in response to time, local distribution, or price constraints. Smart meters also provide a number of other benefits, including enhanced outage management and restoration, improved distribution system monitoring, and utility operational savings.[46] As of 2015, 43 percent of residential electricity customers are serviced through smart meters, and a small but growing number of residential customers are on dynamic electricity pricing tariffs.[r, 47] Microgrids are also becoming more prevalent as DG, storage, and demand-management technologies have decreased in price and the public begins to place greater emphasis on ensuring system reliability during grid outages and natural disasters. While the total capacity of microgrids is now fairly small, communities and states are increasingly encouraging their deployment.[48, 49, 50]

It is important to note that the smart grid is part destination and part vision. How the smart grid evolves will be highly dependent on many factors, including policy, regulatory jurisdictions, investment, regional needs and requirements, market structures, and technologies. Examples of smart grid systems include the following:

- AMI, which consists of smart meters, communications networks, and information-management systems, is capable of delivering electricity usage data every 15 minutes or faster to utilities and their customers. AMI features include remote meter reading and remote connects/disconnects, saving utilities millions of dollars. In addition, meters can be used to support outage restoration efforts and voltage optimization practices in distribution feeders. The practical application of time-varying rates is also made possible by AMI, with results showing up to 30 percent of peak demand reduction among residential customers (observed in the American Recovery and Reinvestment Act of 2009 [ARRA] projects).[51]

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[r] Smart meters are defined here as AMI.

- Fault location, isolation, and service restoration technologies enable the near-instantaneous reconfiguration of distribution circuits through switches and reclosers and greatly reduce outage time experienced by utility customers.[52]
- Voltage optimization technology permits grid operators to actively adjust voltage levels along distribution feeders to ensure proper levels. When operated to keep voltage levels low, but within required ranges, less power is required to meet load requirements, and customers save energy (up to 3 percent or more of their total load).[53]
- Equipment health monitors measure temperature, voltage, and the levels of other parameters in transformers and other devices, permitting a utility to observe deterioration and operate devices more efficiently.[54]
- Synchrophasor systems—consisting of phasor measurement units, communications networks, and data visualization systems—send time-synchronized data on voltage, current, and frequency conditions 30 times per second (or greater) to transmission grid operators, allowing them to detect and diagnose problems that conventional SCADA technology cannot observe. For example, synchrophasor technology can see transmission grid oscillations that can result from improperly set controls, inadequate models, or malfunctioning equipment—permitting grid operators to quickly adjust and correct the system.[55]

In 2009, DOE received $4.3 billion in funds from ARRA[s] to support the demonstration and deployment of these smart grid technologies across the Nation. By adding to efforts well underway in the electric power industry, ARRA helped catalyze the advancement of smart grid technologies, including smart meters, programmable communicating thermostats, automated feeder switches and capacitors, equipment health sensors, and phasor measurement units, plus requisite communications and information-management systems. In some cases, utilities were able to accelerate their smart grid deployment plans by up to 5 years, while others less familiar with the technology were able to start their modernization efforts with ARRA support.[56] An important use of ARRA smart grid funding was to provide the initial support for DOE's ongoing GMI, which is described in detail in the box below.

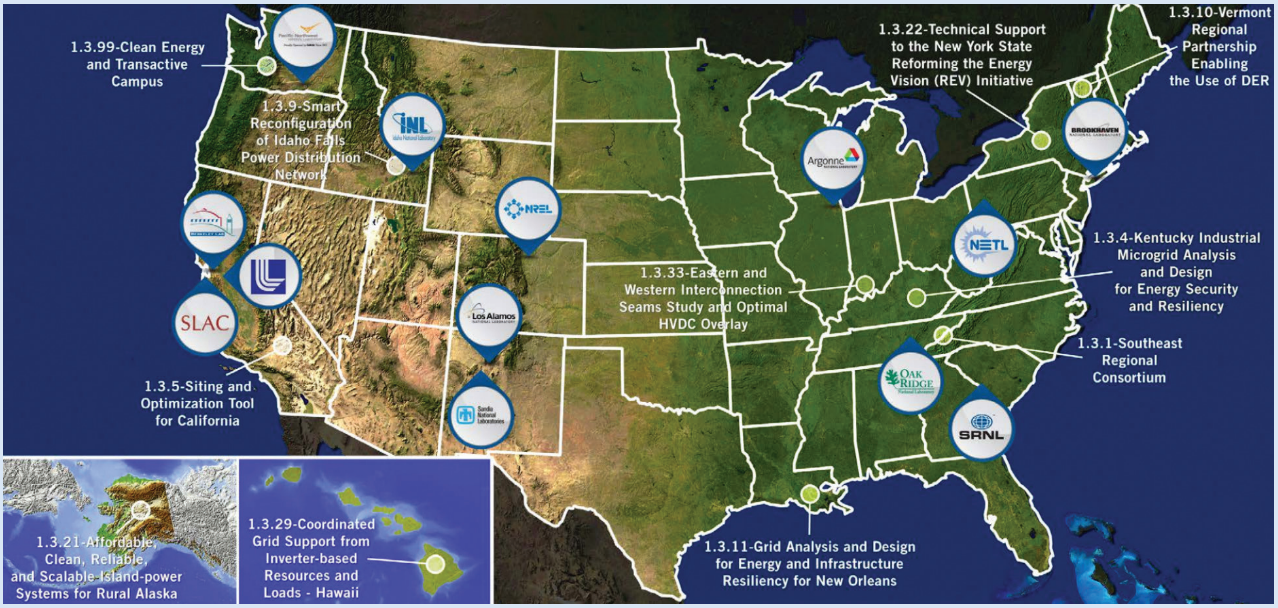
Department of Energy Grid Modernization Initiative

The Grid Modernization Initiative (GMI) is a crosscutting Department of Energy (DOE) effort through which the Department works with public and private partners to develop concepts, tools, and technologies needed to modernize the Nation's grid infrastructure. This work leverages DOE's core capabilities in modeling, computation, systems integration, cybersecurity, and energy storage to help improve system reliability, integrate diverse sources of electricity, advance energy technologies, and provide a critical platform for U.S. competitiveness and innovation in the global economy. In January 2016, the Grid Modernization Laboratory Consortium started 29 regional projects that foster local approaches to grid modernization while contributing to a diverse and balanced national grid.

[s] ARRA was a stimulus package enacted by the 111th U.S. Congress in February 2009 and signed into law on February 17, 2009, by President Barack Obama. ARRA supported many of the initiatives presented within Title XIII (Smart Grid) of the Energy Independence and Security Act of 2007.

Department of Energy Grid Modernization Initiative (continued)

Figure 1-5. Grid Modernization Laboratory Consortium Locations and Regional Projects[t]



Thirteen DOE National Laboratories collaborate with regional partners on national grid-modernization goals throughout the United States. Projects vary widely, with some of these projects displayed in the figure above and detailed further in Table 1-2 below.

Table 1-2. Sample GMI Projects[u]

Project	Summary	Partners
Kentucky Industrial Microgrid Analysis and Design for Energy Security and Resiliency *Oak Ridge National Laboratory, Sandia National Laboratories*	Investigate, develop, and analyze the risks, costs, and benefits of a microgrid utilizing renewable energy systems at the United Parcel Service (UPS) WorldPort and Centennial Hub facilities. Develop roadmap to help industries evaluate microgrid adoption by defining institutional and regulatory challenges associated with development of industrial-based resilient systems.	United Parcel Service, Waste Management, Burns & McDonnell, Harshaw Trane, Louisville Gas and Electric, State of Kentucky
Midwest Interconnection Seams Study *National Renewable Energy Laboratory, Pacific Northwest National Laboratory, Argonne National Laboratory, Oak Ridge National Laboratory*	Convene industry and academic experts in power systems to evaluate the high-voltage, direct current and alternating current transmission seams between the U.S. interconnections. Propose upgrades to existing facilities that reduce the cost of modernizing the Nation's power system.	Southwest Power Pool, Midcontinent Independent System Operator, Western Area Power Administration, Solar Energy Industries Association, Minnesota Power, Xcel Energy, Tetra Tech, Transgrid Solutions, Utility Variable Generation Integration Group, Bryndan Associates
Grid Analysis and Design for Resiliency in New Orleans *Sandia National Laboratories, Los Alamos National Laboratory*	Conduct technical evaluations to assess energy and critical infrastructure vulnerabilities and to identify cost-effective options to improve the resiliency of both the electrical grid infrastructure and the community.	City of New Orleans, Rockefeller Institute, Entergy, U.S. Army Corps of Engineers

Grid modernization projects vary widely in scope and region. Three of these projects are summarized above.

[t] Department of Energy (DOE), *2016 Project Portfolio* (Grid Modernization Laboratory Consortium, 2016), https://gridmod.labworks.org/sites/default/files/documents/GMLC_Portfolio_Brochure-NEW1.pdf.

[u] Department of Energy (DOE), *2016 Project Portfolio* (Grid Modernization Laboratory Consortium, 2016), https://gridmod.labworks.org/sites/default/files/documents/GMLC_Portfolio_Brochure-NEW1.pdf.

There is a new set of demands on grid function and structure that was not fully appreciated 7 years ago when ARRA funds were made available. As the number of integrated, intelligent assets increases, the speed of communication, coordination, and control will require more distributed, automated (machine-to-machine) intelligence dealing with subsecond decisions that cannot be managed by human operators in real time. The scope of "smart" must evolve to include machine learning to manage the co-optimization of systems and subsystems while maintaining system reliability as more DER are integrated into grid operations.

The key ingredient to enabling this capability are ICT networks that not only support grid operations, but also permit, where appropriate, the grid's convergence with other infrastructures, including buildings, transportation, water, and natural gas infrastructures. The integration of intelligent assets across these systems can provide enhanced levels of efficiency, asset utilization, and innovation. Speed and precision will be essential elements for ensuring a highly reliable electricity system. Well-designed smart grids are structured to enable adaptation to ever-changing device characteristics and requirements. At the same time, new devices that impact the grid and utilities are finding that vendors are retiring the manufacture of analog meters, which means that when meter replacement is required, it will lead to the need for building automated meter infrastructure.

The Electricity System and Grid Management Are Facing New Challenges

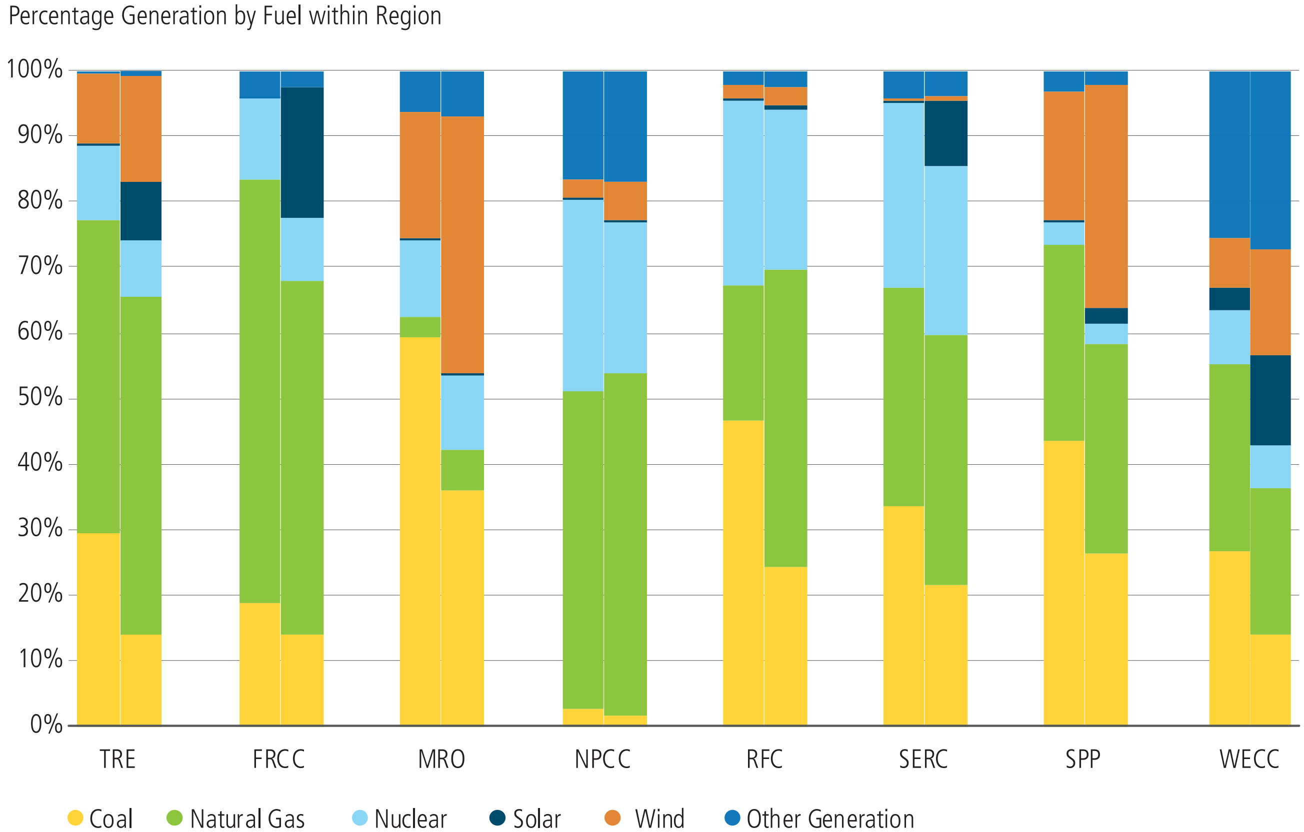
While electrification and digitization have created new opportunities for utilities to improve reliability and reduce costs, other trends in electricity generation have created new challenges for grid management. The increasing deployment of variable energy resources (VER) such as wind and solar power, the interaction of DER with baseload generation, and the changing role of electricity customers have increased the complexity of matching electricity supply with demand at all times. While they pose challenges, each of these trends has distinct advantages, such as helping to enable the decarbonization of electricity generation, increasing consumer options and services, and advancing grid-management solutions, such as flexibility and grid-scale storage.

The Changing Generation Profile

The U.S. generation fleet is transitioning from one dominated by centralized generators with high inertia and dispatchability to one that is more "hybridized," relying on a mixture of traditional, centralized generation and variable utility-scale and distributed renewable generation.[57] In 2005, the top six generation sources, in descending order, were coal, nuclear, gas, hydro, petroleum, and renewables. By 2015, gas and coal were tied at the top, followed by nuclear, renewables, hydro, and petroleum.

Generation changes between 2016 and 2040 (Figure 1-6) are expected to be uneven, both by technology and region. Over this time period, nuclear and hydroelectric generation are projected to be relatively flat. The shift from coal-fired to natural gas–fired generation is strongest in the eastern half of the country (where growth in renewable electricity is modest), while the western United States is experiencing rapid growth in renewables.[58] Regional generation mixes vary significantly from the national generation profile, and there are major differences among the regions in both generation mix and the addition and retirements of capacity.

Figure 1-6. Comparison between Generation Fuel Mix by North American Electric Reliability Corporation Region, 2016–2040 [59]



Based upon the Energy Information Administration's "Annual Energy Outlook 2016" business-as-usual modeling results, the regional variations in generation fuel of 2016 (left columns) are projected to continue through 2040 (right columns). Solar generation is expected to play a significant part in Texas (Texas Reliability Entity, or TRE), Florida (Florida Reliability Coordinating Council, or FRCC), the southeastern United States (SERC Reliability Corporation, or SERC), and the western states, particularly the Southwest and California (Western Electricity Coordinating Council, or WECC). Wind generation is anticipated to be largely concentrated in the Upper Midwest (Midwest Reliability Organization, or MRO), New England (Northeast Power Coordinating Council, or NPCC), and the western states (WECC). The Upper Midwest (MRO), ReliabilityFirst Corporation (RFC) region, and Southwest Power Pool (SPP) are expected to decrease their coal generation capacities, but will still retain over 20 percent of their generation capacity from coal. Hydropower accounts for the largest portion of "Other Generation" in New England and WECC.

VER are increasing in both capacity additions and generation. These additions have been enabled by new technologies, cost reductions, and a range of policies. Specific policies to support VER (and other clean energy options) include state and Federal production and investment tax credits, renewable portfolio standards in 27 states, and net metering policies or other incentives in 43 states. California offers an example of VER potential. The California ISO expects to achieve a 30 percent penetration level of VER by 2020 and 50 percent penetration by 2030.[60]

Information Needs for Load-Management Increase with High VER/DER Penetration

The introduction of new grid control and optimization algorithms that take advantage of VER and DER and load flexibility could contribute to U.S. grid reliability and have a range of benefits, including the reduction of renewables curtailment; the reduction in transmission and distribution congestion; and improvements in power and grid vulnerability quality.[61]

Renewable resources—both utility-scale and distributed—are, however, more variable in their power production, requiring investment in assets, systems, and processes to mitigate such variability. VER-dominated resource portfolios will require more rigorous grid controls than those currently exercised by today's grid operators. Also, in the absence of comprehensive visibility to grid operators of—and information about—DER and automated DR techniques, it is unclear how much decarbonization potential is being underutilized and undervalued.

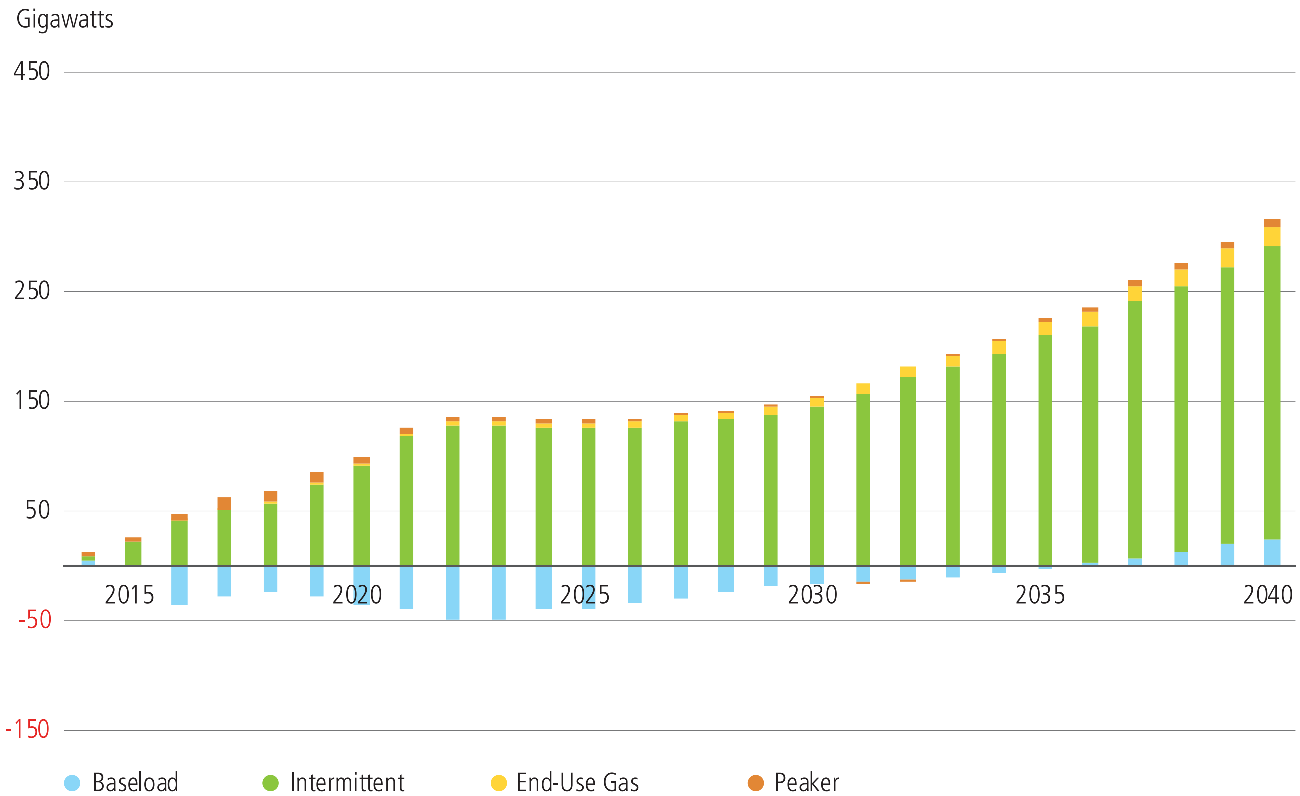
In addition, the absence of comprehensive information on the total available and active power production from distributed resources, principally solar, can complicate grid management. States are working to address these issues. The California Solar Initiative, for example, is part of a California Public Utilities Commission mandate to build and maintain a publicly accessible data set of capacity and technical specifications of DG systems throughout the state.[62] In Hawaii, a collaboration between DOE and the Hawaiian Electric Company is designing new capabilities for energy-management systems,[63] introducing greater visibility of DG by factoring advanced 15-minute, short-term wind and solar forecasting into its energy-management systems decision-making process.

Role of Baseload Generation

Electricity demand has always been variable. To manage this variability, system operators have traditionally relied on a generation mix that falls into three general categories: baseload, intermediate and peaking plants, and some demand-side resources such as DR. Because baseload units are usually capital-intensive generators with low operating costs, they are operated at high output, typically with capacity factors above 50 percent.[64] Intermediate units vary their level of output to keep the system in balance with changing levels of customer demand. Peaking plants have low capital costs and high operating costs and are used in periods when demand is high (peaks). There is an optimal mix of these three types of resources based on the tradeoff between capital costs and operating costs—recognizing the amount of time each type of resource is expected to operate.

Notwithstanding gains in VER, today's electricity system is highly dependent on baseload generation. Approximately 86 percent of the current grid-connected electricity is fueled by coal, natural gas, and nuclear.[65] Based on the Energy Information Administration's business-as-usual projections, by 2040 the United States will still rely on coal, nuclear, and natural gas to provide 74 percent of its grid-connected power.[66] In the long run, grid-scale storage could be a game changer, affecting the need for traditional baseload in the very long term. Storage technology costs and barriers and diffusion rates will, however, greatly affect the role of grid-scale storage in transforming the electricity system.[67] Figure 1-7 also shows significant variable (or intermittent) generation capacity, including wind and solar, coming online through 2040.

Figure 1-7. Cumulative Utility-Scale Net Capacity Additions, 2015 to 2040[68]



Under Energy Information Administration business-as-usual assumptions, retirements in baseload capacity are projected to fully offset additions in baseload capacity between 2015 and 2026, where baseload is considered coal, nuclear, and natural gas combined-cycle plants. Variable (or intermittent) generation capacity (which includes wind and solar) is expected to increase throughout the entire time period. Natural gas combustion turbine (peaker) capacity is expected to decline modestly beginning in 2021. By 2027, natural gas net capacity is projected to increase modestly, driven by natural gas combined-cycle plants. Capacity of natural gas–fired combined heat and power plants begins to ramp up in the latter decade of the projection period.

Historically and in business-as-usual projections, baseload generation has provided a range of essential reliability services. High capacity factor and low- or zero-carbon-emitting generation plants can reduce reliability risks, as system operators work to manage the increased complexity associated with variable generation and controllable load. In a future where significant DG co-evolves with utility-scale renewable resources—notably solar—there are several issues to consider regarding baseload generation, including the following:

- Changes in defined baseload characteristics and requirements as the sector transforms to higher VER and DER and utility-scale storage
- The extent to which central-station, large-scale power generation is the least-cost/best-fit platform for an electricity sector with diversified utility-scale and distributed resources of all types
- The degree to which long-term resiliency requirements for ensuring a robust and secure system argue for or against baseload generation
- How reserve margin requirements might change in low-net-demand/high-resource markets.

The amount of baseload generation needed to support load and balance resources has long been addressed through established ratemaking processes and state-level energy planning. Consideration of these issues and the ongoing value of traditional baseload resources is, however, a new and important question for DOE, the

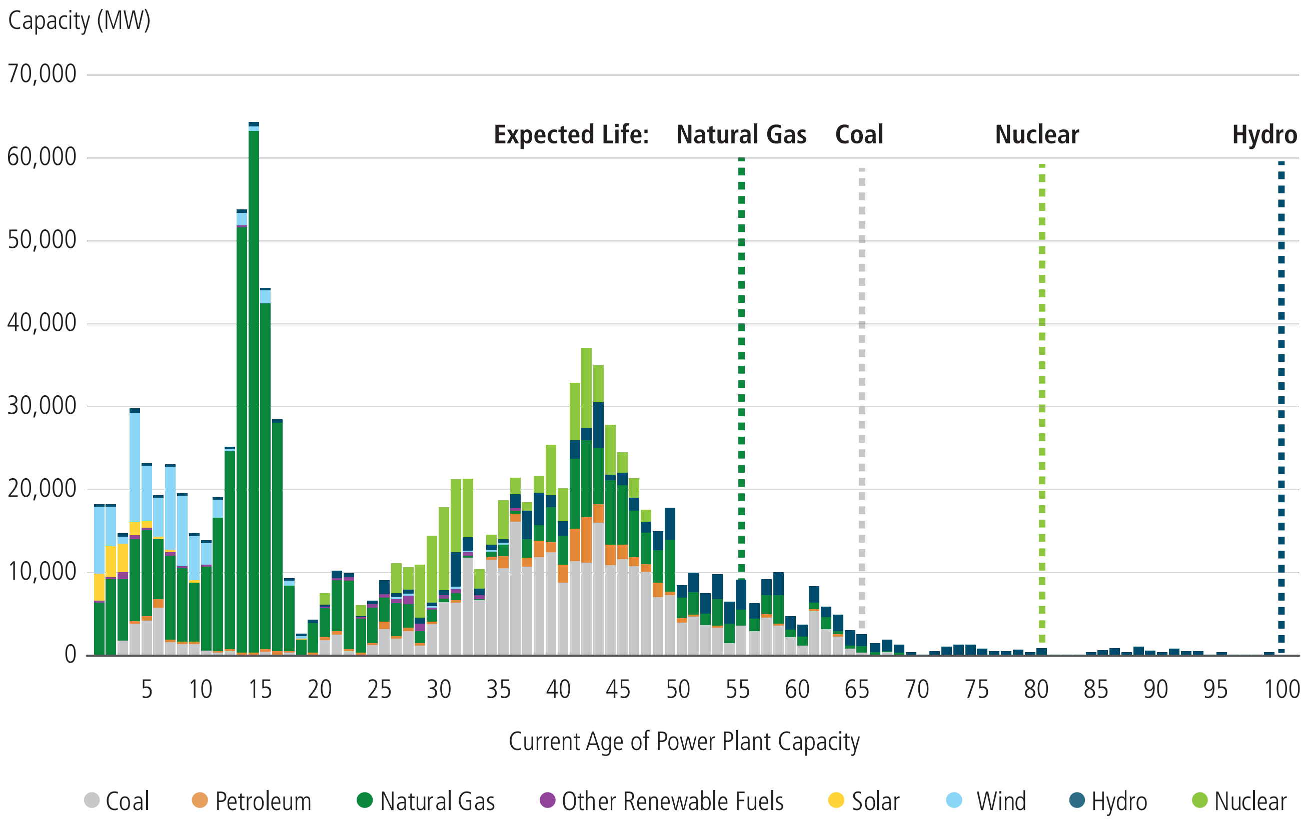
Federal Energy Regulatory Commission (FERC), the North American Electric Reliability Corporation, states, industry, and the range of stakeholders involved in system changes and transformation.

Aging Infrastructure: Challenges and Opportunities

Like any infrastructure, the physical components of the electricity system are constantly aging. The continual maintenance and replacement of electricity system infrastructure components, however, provides an important opportunity to modernize the electricity system. Replacement of antiquated infrastructure with new technology can enable better failure detection, upgrade technical capabilities, and improve cybersecurity.[69] Investments in new control and distribution-management systems can harness the latent capabilities of smart meters, digital communications systems, and system-control devices to reduce outages and increase efficiency.[70] New transmission technologies allow operators to get more capacity out of the same rights-of-way and better monitor the health and status of the grid.[71]

The electricity infrastructure is, however, large and complex, and equipment has a long lifespan; modernization is an ongoing process.[72] Only a small minority of power plants will reach their expected lifespan over the next two decades (Figure 1-8). Refurbishment, upgrade, and maintenance can extend the useful life of a power plant far beyond its planned service life. Power plants are overhauled on a regular basis, and some are repowered to run on a different fuel or at a higher output capacity at some point during their useful lives. Large portions of a facility may be replaced over many years, providing opportunities to increase efficiency, add new technologies, and otherwise modernize plants.

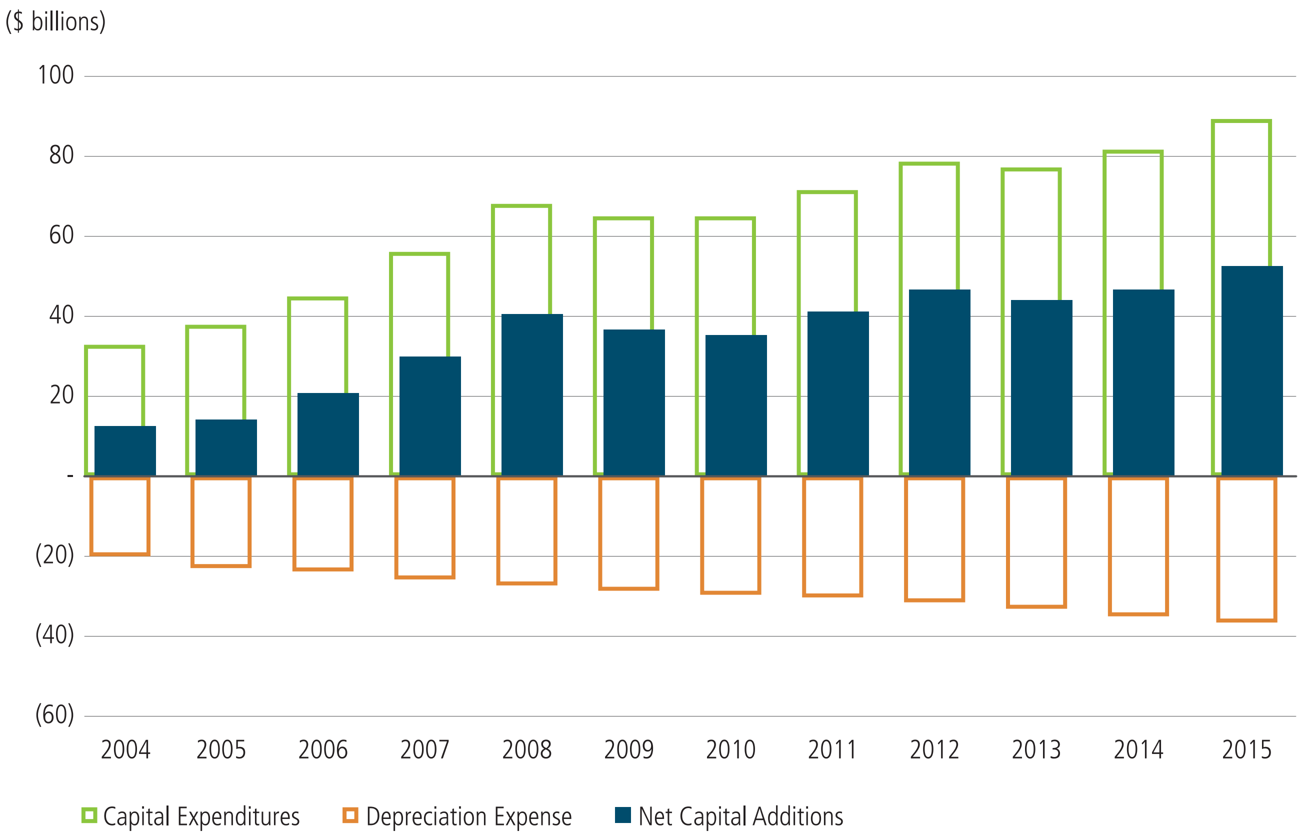
Figure 1-8. Current Age and Expected Life of Generation Fleet by Nameplate Capacity, 2015[73]



Much of the U.S. generation fleet is 11–20 or 41–50 years old, with plants over the age of 50 being dominated by coal and hydropower. Plants under 20 years of age are dominated by natural gas and wind. Hydropower has the oldest fleet, followed by coal, nuclear, petroleum, and biomass. Expected life of the current fleet ranges from 55 years for natural gas to 100 years for hydropower generation. Capacity is measured in megawatts (MW).

For distribution systems, asset monitoring, investment, and replacement is at the core of a utility's mission and business model; utilities and their regulators are diligently ensuring the continued reliability of their systems through proactive replacement and repair. Data availability is a challenge for comprehensive analysis of distribution utility infrastructure; over 3,000 utilities have cumulatively installed millions of poles, small transformers, and other distribution equipment. Financial records provide some insights into the aggregate age of a utility's overall assets and suggest that investment in grid assets is outpacing the depreciation of the overall asset base; this is shown in Figure 1-9, which depicts the widening change between capital investments and depreciation charges.

Figure 1-9. Utility Operating Company Annual Capital Expenditures, Depreciation, and Net Capital Additions, 2004–2015[74]



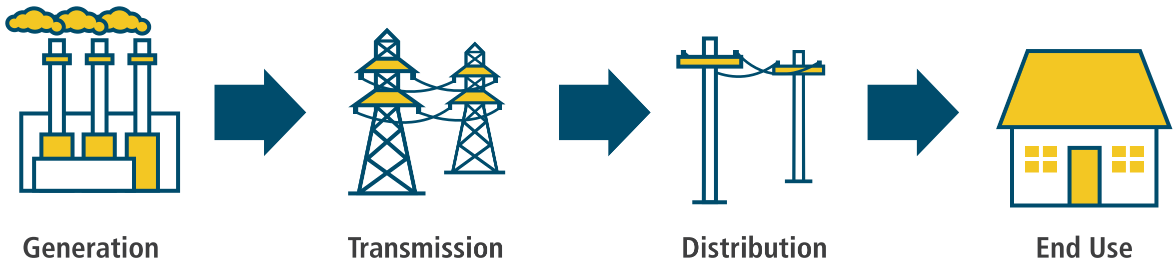
Utility investment in capital (in green) has routinely outstripped depreciation expenses (in red) over the last decade, leading to positive and growing net capital additions (in blue). This means that utilities are adding property, plants, and equipment at a faster rate than they are losing it to wear and tear or obsolescence.

New Technologies Enable Two-Way Electricity Flows and Change Grid Management

For over 100 years, the electricity system has been operated through one-way flows of electricity and information. Figure 1-10 depicts this historical one-way flow of electricity service, from power produced to power consumed, with customers largely functioning in an analog environment.[v]

[v] Analog and digital technologies both transform information into electric signals. Analog technology translates information into electric pulses of varying amplitude, while digital technology translates information into binary form (zeros or ones), where each bit is representative of two distinct amplitudes.

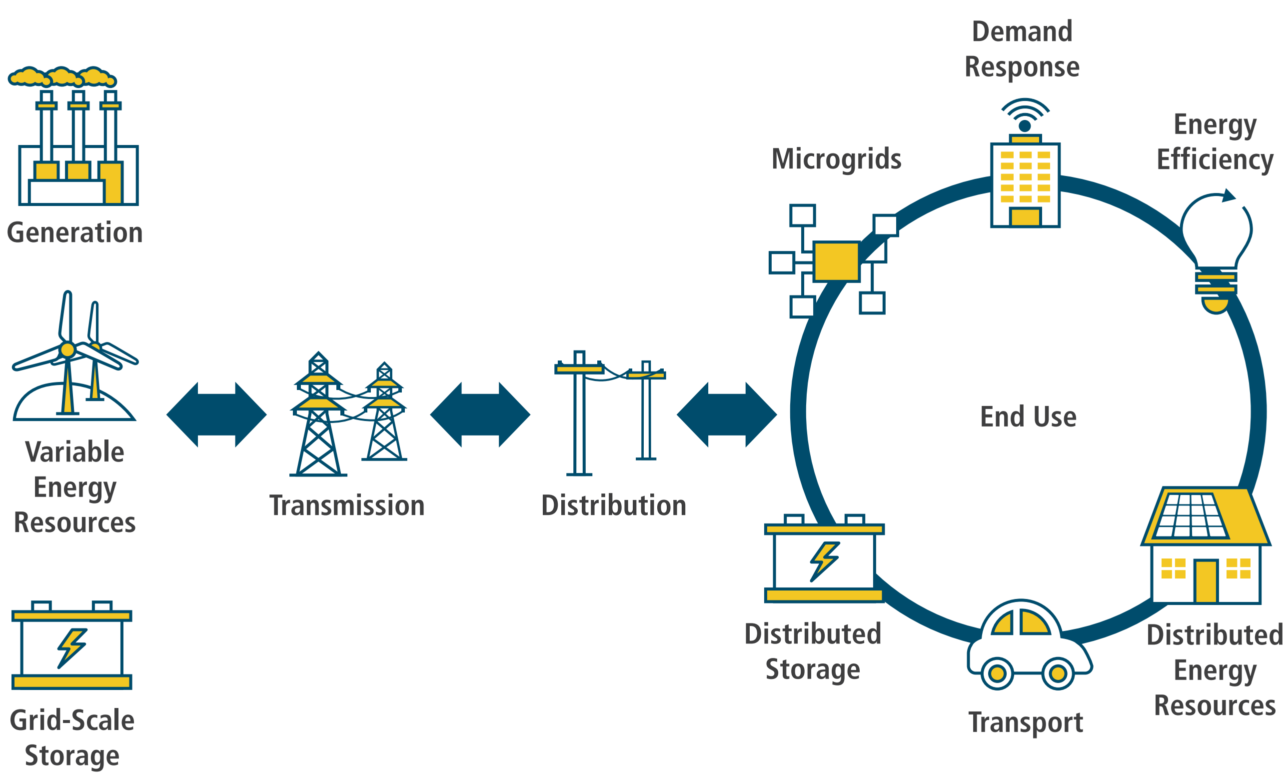
Figure 1-10. Traditional One-Way Flow Electricity Supply Chain[75]



The power grid was traditionally designed to move electricity from large generators to end users. Arrows represent power flows.

The generation and smart grid technology innovations described earlier can reduce grid costs and improve efficiency, as well as save time and effort; until recently, computer processing speeds and low-cost digital measurement and sensor technology limited the ability of grids and consumers to manage end-use behavior in highly granular ways. The development of new technologies to manage these end uses has also enabled two-way flows on the electricity system. Figure 1-11 summarizes key changes in the electricity system, where such two-way flows are possible and more common, and where digitization is a key enabler of a new range of services, including increased flexibility, higher system efficiency, reduced energy consumption, and increased consumer options and value.

Figure 1-11. Emerging 21st-Century Electricity Two-Way Flow Supply Chain[76]



The emerging 21st-century power grid will incorporate responsive resources, storage, microgrids, and other technologies that enable increased flexibility, higher system efficiency, reduced energy consumption, and increased consumer options and value. Arrows represent power flows. Figure 1-11 also depicts key factors that are disrupting traditional modes of grid management and operations.

New control technologies and an evolution in electricity market design will facilitate the reliable and economic operation of the new capabilities in a 21st-century grid. ICT has already improved the operations of the grid within and across regions. For example, advanced inverters on distributed solar resources can provide a variety of localized grid support functions, including voltage regulation and frequency ride through.[w, 77] Nearly all market regions have incorporated active power control of wind turbines into their dispatch procedures to manage transmission congestion.[78] Also, several market regions have changed market rules to reflect the fast reaction of energy storage to frequency regulation operating signals.[79]

Customer Engagement, New Business Models, and the Emerging Role of Aggregators

Throughout the industry's development, the electricity customer was viewed as "load"—the aggregate accumulation of demand that utilities served, supported by a "ratepayer." This view of customers as load and ratepayer, largely passive because there were no real alternative options to utility service, was operative through the early 1980s. Changes in the electricity sector starting in the mid-1980s, however, have prompted utilities and emerging competitors to slowly shift their "customer as load" views to a point of view that is much more, and more simply, customer-centric.

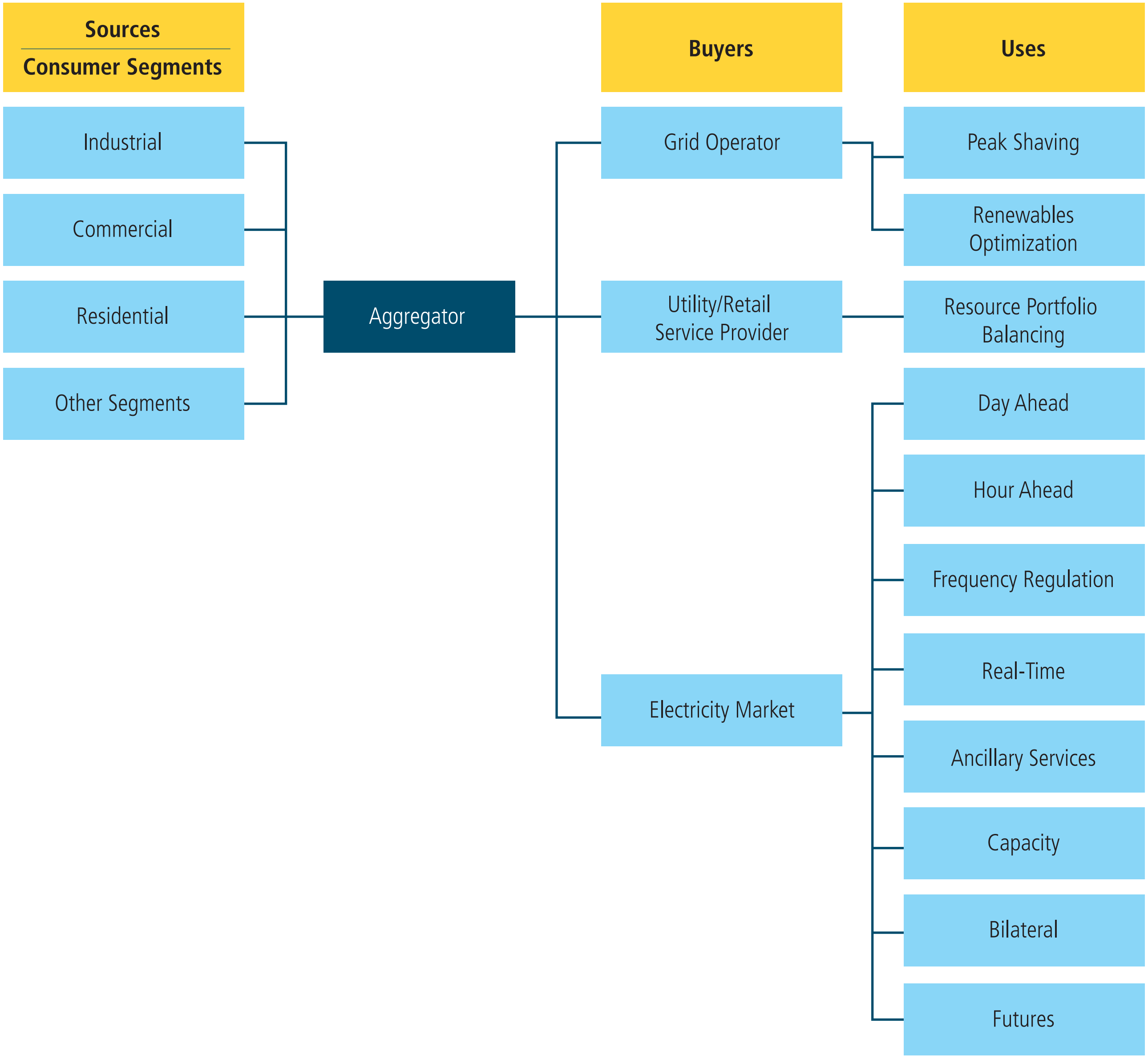
States and utilities are exploring new distribution utility business models while the private sector is providing new products and services to consumers. In the past decade, the electricity industry has seen a large increase in the number of businesses focused on providing electricity-related products and services outside of traditional utility business models.[80] These businesses have found opportunities to provide value to customers through innovative technologies, novel business models, and supportive state and Federal policy decisions—they are also changing the role of some ratepayers from passive consumers of electricity to informed shoppers and producers of electricity and related end-use services.[81] Many of these services are enabled by the recent widespread adoption of advanced electricity metering and communication systems that provide ratepayers with unprecedented levels of information regarding their own energy consumption patterns.[82]

Many businesses are now providing DG, end-use energy services, and aggregated demand services. These "aggregators" are playing a growing role in this customer-centric view of load. Aggregation involves grouping distinct end users in an electricity system, including traditional consumers; consumers that produce power for grid use; third-party onsite producers, such as energy service companies; competitive retailers; and facilities management service entities. This aggregation of consumers enables it to act as a single entity, providing a service to utilities under a contract, or to centrally-organized wholesale markets operated by ISOs/RTOs through participation in resource auctions. In short, aggregators are enterprises that orchestrate and manage aggregated electricity-related services enabled by new technologies and the smart grid. Value realized through aggregation transactions is typically shared between aggregators and their clients.

The core workflows of aggregators involve applying technical services—such as engineering analytics, process system design, asset acquisition and installation, and ongoing operations and maintenance—as well as economic services—such as leasing to support adoption of services, shared savings-based transactions that reduce client costs, and ownership of systems for which a monthly fee is charged to clients. While there are many variations of these general enterprise activities, Figure 1-12 provides a general depiction of the consumer and buyer categories for aggregators and the potential system value that could be associated with various aggregations.

[w] Frequency ride through refers to a generation technology's ability to maintain operating through momentary grid disturbances, like a dip in voltage or frequency.

Figure 1-12. Aggregator Sources, Markets, and Services



Aggregators develop "load portfolios" from various combinations of consumer segments. Aggregators sell DR products for use by utilities across all three buyer types using specific utility-offered DR programs, or through negotiated DR contracts with aggregators. There are three principal buyers for aggregator services: utility grid operators, utility retailers, and utilities interacting with other wholesale market participants to serve day-ahead, hour-ahead, and real-time markets (which include frequency regulation and other essential reliability services).

The roles that non-utility aggregators play can be of great value in supporting grid reliability and flexibility. The growing penetration of DER increases the depth and diversity of value-added services aggregators can offer. Aggregators are not, however, regulated entities; their value propositions tend to be riskier than those of regulated entities. Their client engagements are also subject to negotiated terms and conditions that can result in an uneven distribution of benefits between members of an aggregation, as well as between the aggregator and all clients. To maximize their value to the electricity system and grid operations, aggregators need adequate capitalization, sufficient pooling of clients to ensure reliable execution of DER-related services, and improved execution of client-related activities. Their activities also need to be both visible and reliable for distribution utilities to maximize the value of these services to the operation of the grid.

Regulated utilities can also aggregate demand through specific programs approved by regulators. The economic and reliability value of DR programs depends on customer availability and commitment to participate. DR challenges include partial delivery against contracted DR volumes; the inability to sustain DR commitments for the entire duration of an event; and nonparticipation when called on for service. These challenges impact daily resource planning and production where gaps in DR performance must be addressed with other resources.

Workforce Retirements, New Skillsets, and Shifting Regional Needs Pose Challenges for a Changing Electricity Sector

Realizing the full potential of shifts in generation technologies, operations tools, and industry structure will require an electricity industry workforce capable of adapting and evolving to meet the needs of the 21st-century electricity system. A skilled workforce that can build, operate, and manage a modernized grid infrastructure is an essential component for realizing the full value of a modernized electricity system.

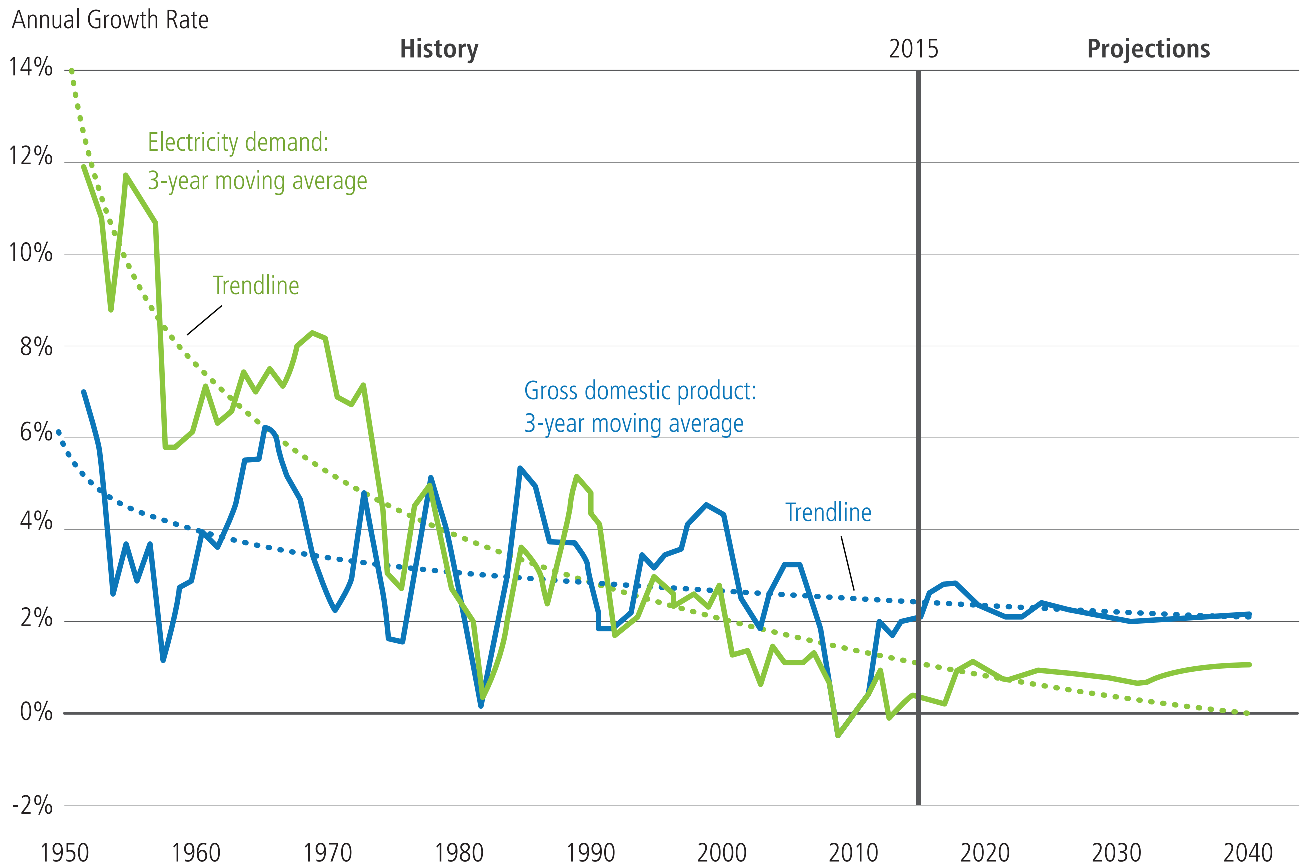
Jobs in the electricity industry require a varied range of new skills. Traditional utility jobs include lineworkers, power plant operators, technicians, pipefitters and pipe layers, and engineers. Additional field support includes truck drivers, inspectors, mechanics, and electricians.[83] While traditional jobs such as lineworkers will continue to be needed, increases in renewable energy generation and ICT will change the skillsets required for some jobs and the relative need for employees in different roles.

The United States has also been experiencing a long-term population shift from rural to urban areas since the start of the last century. According to the U.S. Census Bureau, around 20 percent of the U.S. population lived in rural areas in 2010, while more than 70 percent lived in urban areas.[84] This makes it especially challenging for utility companies located in rural areas to retain and attract a highly skilled workforce. Also, since the early 2000s, baby boomers are retiring in increasing numbers.[85] Industry surveys indicate that roughly 25 percent of employees will be ready to retire within the next 5 years.[86, 87] Fifteen percent of lineworkers are forecasted to retire between 2016 and 2020, in addition to 19 percent of technicians, 17 percent of non-nuclear plant operators, and 15 percent of engineers.[88] One recent survey suggested that 43 percent of utilities view retirements and an aging workforce as one of their most pressing challenges.[89] These retiring workers have experience and skillsets that are difficult to replace.

The Electricity Sector Is Enabling a More Productive Economy and Reducing Carbon Emissions

Since the 1950s, growth in U.S. electricity consumption has gradually slowed each decade (Figure 1-13). A number of factors have led to this gradual slowing of electricity demand growth rate, including moderating population growth, improvements in the energy efficiency of buildings and industry, market saturation of certain major appliances, and a shift in the broader economy to less-energy-intensive industries.[90, 91]

Figure 1-13. U.S. GDP and Electricity Demand Growth Rates, 1950–2040[92]



U.S. electricity demand growth has slowed since the 1950s and is projected to remain flat through 2040, based upon business-as-usual assumptions. Though national GDP has slowed over the same time period, electricity growth has slowed significantly more than GDP.

Past and future electricity demand growth rates are driven by several sector-specific trends that reflect broader economic changes. For example, while industrial demand growth is virtually flat, productivity (as measured by units of GDP produced per unit of energy consumed) is growing. The industrial sector's electricity productivity nearly doubled between 1990 and 2014. Projections suggest that grid-purchased electricity will rapidly increase in the industrial sector from 2010 until 2025, after which growth is projected to slow to 2040 when it reaches 1,218 terawatt-hours (25 percent above the 2010 level).[93]

Decarbonizing the Electricity System

U.S. power sector emissions have declined by 20 percent since 2005, largely due to a slowing of electricity demand growth and the accelerated deployment of lower-carbon generation.[94] Low natural gas prices have led to substantial substitutions of lower-emitting gas for high-emitting coal. This is in part because the electricity sector has the broadest and most cost-effective abatement opportunities of any sector, including multiple zero-carbon and low-carbon generation options—such as nuclear, hydropower, solar, wind, geothermal, biomass, and fossil generation with carbon capture and storage—as well as many operational and end-use efficiency opportunities. The electricity sector has been and—depending on the interplay of technology innovation, market forces, and policy—is likely to continue to be the first mover in economy-wide GHG emissions reductions. It will also play a major role in the levels of decarbonization needed from other sectors, such as transportation.

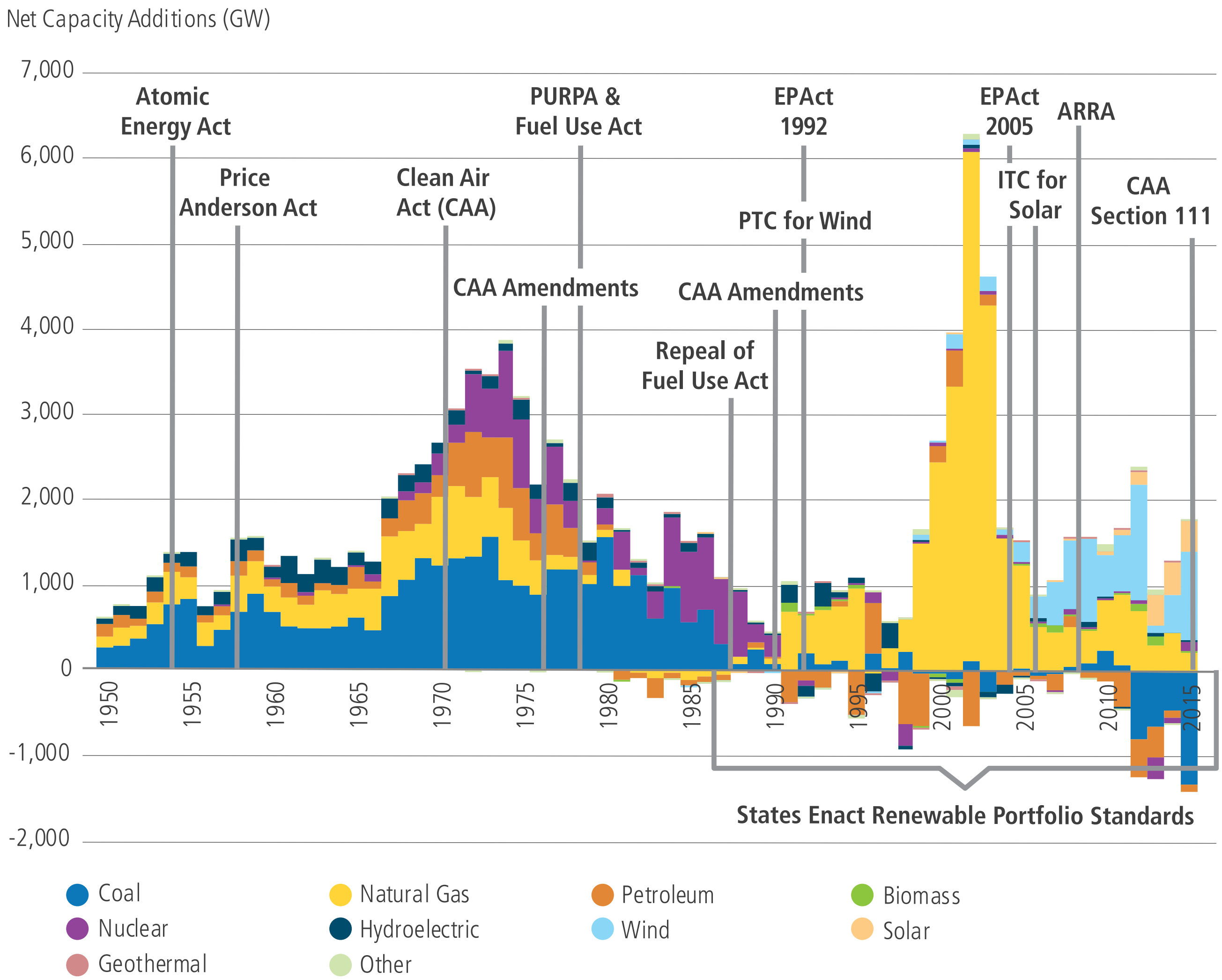
The importance of decarbonization argues for ensuring that Federal and state policies provide compelling incentives for transitioning the electricity sector as part of achieving national goals. Options for decarbonizing the electricity sector must address significant barriers in three broad categories: technical (e.g., long time frames for research, development, demonstration, and deployment [RDD&D] gestation); structural (e.g., long time frames for capital stock turnover); and policy (e.g., difficulties in mobilizing needed investment).

Investment in innovation is needed, including investment in advancements of known technologies, as well as in fundamental breakthroughs. The potential for research, development, and demonstration to increase deployment of existing technologies and unlock future technologies is significant, and long-range planning must take technology time scales and deployment timelines into account. The innovation process is iterative, requiring early deployment and technology learning over time. Also, beyond enabling domestic GHG reduction and improving economic well-being, innovation can significantly accelerate and ease the path to global emissions reductions, both of which are critical to reducing adverse climate impacts.

In addition, transitioning to a low-carbon electricity future requires policies that accelerate deployment of low-carbon generation.[95] The long time frames for capital stock turnover also motivate early action. There are Federal tax credits and state policies, such as renewable portfolio standards, that are driving investment in energy efficiency and renewable power, but additional policies may be needed for the accelerated deployment of these and other critical grid-related technologies.

Well-designed policies can help facilitate and enable market mechanisms that drive least-cost approaches to mobilizing and leveraging public and private investment, minimizing the risk of stranded assets, and reducing emissions. Conversely, policies that replace or significantly interfere with market mechanisms can have unintended and long-term impacts. For example, as Figure 1-14 demonstrates, the passage of the Powerplant and Industrial Fuel Use Act (FUA) in 1978, largely in response to the Arab oil embargo of 1973 and perceived shortages of natural gas, fundamentally outlawed the use of natural gas in power generation. After the passage of the FUA, there was a significant drop in natural gas generation capacity additions. Gas capacity only began to grow again after the repeal of the FUA in 1987 and the development of natural gas combined-cycle turbines. In the interim years when the law was in effect, significant coal generation capacity was added to the U.S. generation fleet, with long-term impacts on the generation mix and carbon emissions. Figure 1-14 shows several additional examples of polices driving changes in the generation mix. Further details on these policies can be found in the Appendix (*Electricity System Overview*).

Figure 1-14. Net Generation Capacity Additions, 1950–2015[96]



Capacity additions of different generation technologies came in waves that were largely influenced by policy, fuel costs, and technology development. The 1930s and 1940s fostered the development of hydropower; nuclear power was widely deployed in the 1970s after nuclear research for peaceful uses was allowed; natural gas additions peaked in the 2000s; and non-hydro renewables are quickly growing in the 21st century. Note that the deployment of these generation technologies followed enabling Federal policies and technology development—e.g., nuclear power reactors and natural gas combined-cycle turbines—by several decades. Acronyms: Clean Air Act (CAA), Energy Policy Act of 1992 (EPAct 1992), Energy Policy Act of 2005 (EPAct 2005), gigawatts (GW), Investment Tax Credit (ITC), Production Tax Credit (PTC), Public Utility Regulatory Policies Act (PURPA).

Many generation owners and most economists maintain that a price on carbon is the most efficient means of achieving decarbonization. Many investors already assume a shadow price on carbon when making investment decisions. States have also taken a number of actions to reduce conventional pollution and, more recently, GHG emissions beyond what is required under national environmental statutes. In addition, many cities have set explicit goals to reduce GHG emissions and have enacted policies to help meet those goals. Finally, several RTOs/ISOs have issued studies on the effects of adding a carbon charge to wholesale markets. ISO–New England stakeholders are, for example, discussing changes to their ISO market design that includes a carbon price.[97]

States are also pursuing a range of energy efficiency policies with climate co-benefits. These efforts are important and effective, but they tend to underestimate the value of other zero- and low-carbon technologies, such as nuclear power and carbon capture and storage for both natural gas and coal generation. The GHG-mitigation benefits of the existing fleet of nuclear power plants, which provide 60 percent of U.S. zero-carbon generation, merit consideration as valuable, sustainable resources, where current wholesale market designs and regulatory-based cost-of-service valuations tend to not "price in" these values. Hydropower is also carbon-free and a major source of electricity storage as well.

Finally, the United States has already made significant progress toward a higher-efficiency, lower-carbon electricity system, and more progress is expected going forward. Decarbonizing the power sector will also require increased carbon-free energy; improved energy efficiency; active energy management of end-use facilities; and improved grid controls, including more responsive centralized generation—all of which can be optimized by data and communications systems.[98] To fully realize the carbon reductions potential of the electricity sector from generation to end use, digitization to create a more connected, interactive, and integrated system will be essential.

The Electricity System Is a National Security Asset

Without access to reliable electricity, much of the economy and all electricity-enabled critical infrastructures are at risk. These include our national security and homeland defense networks, which depend on electricity to carry out their missions to ensure the safety and prosperity of the American people. In a November 2015 report on the electric grid and national security, the Center for Naval Analyses noted that

> "Assuring that we have reliable, accessible, sustainable, and affordable electric power is a national security imperative. Our increased reliance on electric power in every sector of our lives, including communications, commerce, transportation, health and emergency services, in addition to homeland and national defense, means that large-scale disruptions of electrical power will have immediate costs to our economy and can place our security at risk. Whether it is the ability of first responders to answer the call to emergencies here in the United States, or the readiness and capability of our military service members to operate effectively in the U.S. or deployed in theater, these missions are directly linked to assured domestic electric power."[99]

As the central role electricity plays in the 21st-century economy and electricity's broader role in national security are examined, it is instructive to briefly review the U.S. policy response to oil dependence. A single action—the 1973 Organization of Petroleum Exporting Countries oil embargo—exposed the U.S. economy's dependence on a single commodity. Since the embargo, reducing the country's overall dependence on oil, including imported oil, has been a fundamental component of U.S. national and energy security. A sustained, 40-year Federal policy commitment has enabled a robust, global oil market; a diversity of petroleum suppliers; the world's largest strategic oil reserve; international mechanisms for concerted action in the event of disruptions; increased domestic oil production; a shift away from oil-fired power generation; more-efficient vehicles; and a host of other benefits. The U.S. Government is also modernizing its Strategic Petroleum Reserve to more appropriately manage its value as articulated in statute—reducing the harm to the U.S. economy from oil price shocks and global supply disruptions.

The United States now needs an analogous approach to electricity. Unlike oil supplies in the 1970s, where oil imports were rapidly increasing, most of the electricity consumed in the United States today is generated domestically (although current cross-border transmission between Canada, Mexico, and the United States is essential to electricity system reliability and can make increasingly significant contributions to grid reliability and resilience in the future). Electricity cannot, however, currently be stored at scale; establishing a "Strategic Reserve" for electricity is not a policy option as it was for oil in the late 1970s. Disruptions in the flow of electricity today would have profound effects on the economy and national security, most likely even greater than those of the oil embargoes of the 1970s. As U.S. policies establish new pathways for the electricity sector to enhance economic competitiveness and environmental goals, it is also essential that these policies work in concert with national security goals. Doing so is challenging but achievable.

The Threat Environment Is Changing for Electricity Systems

The electricity system faces a range of growing threats to its reliability and security. These include cyber and physical threats, natural disasters and increased extreme weather events due to climate change, aging infrastructure, the interconnectedness of an increasingly data-driven economy, and a changing technical and operational environment.

Cybersecurity is a particular concern for national and homeland security. Cyber attacks increasingly may resemble conventional attacks that are designed to disrupt physical systems. Malicious cyber activity against the electricity system and its suppliers is growing in sophistication. The cyber attack on Ukraine's electricity systems in December 2015 serves as a warning. Three of Ukraine's regional electricity distribution companies experienced simultaneous cyber attacks on their computer and control systems, precipitating the disconnection of multiple electricity substations. The result was several outages that caused approximately 225,000 customers in three different distribution-level service territories to lose power for hours.[100]

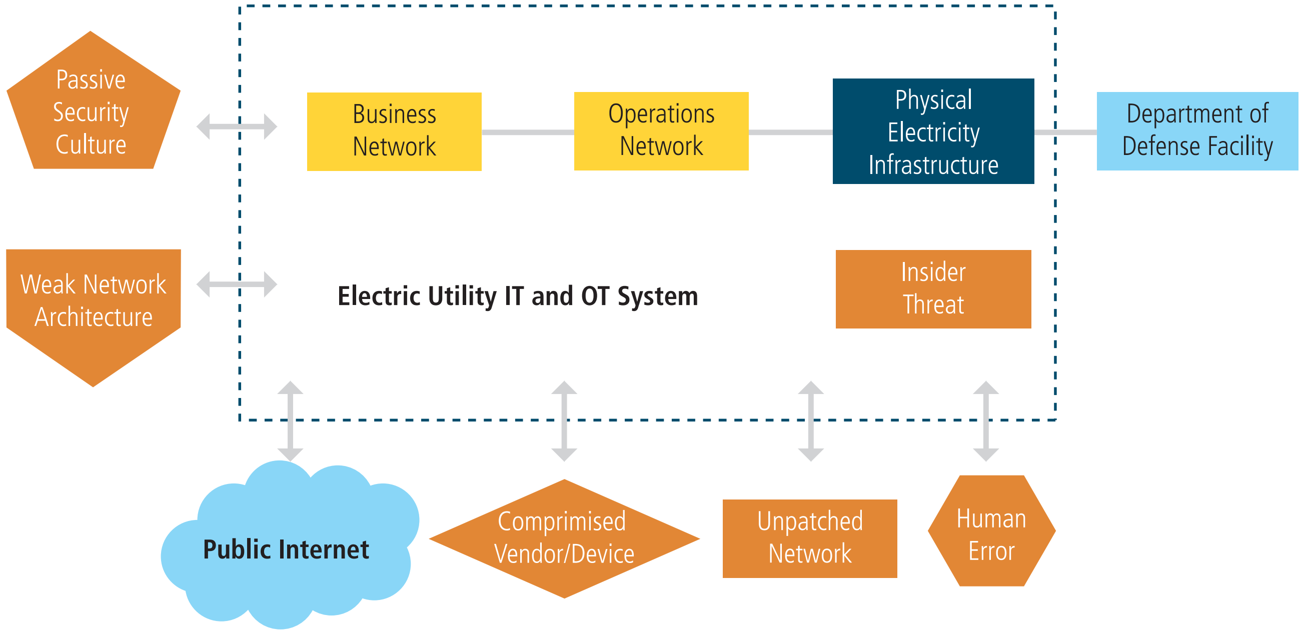
One of the hackers' strongest capabilities was their performance of the long-term reconnaissance operations required to learn the environment and execute a highly synchronized, multi-stage, multi-site attack. These highly targeted, long-term campaigns, called "advanced persistent threats," are generally designed to satisfy the requirements of international espionage and/or sabotage.[101] This type of well-funded and well-staffed attack has long worried U.S. security officials. Michael S. Rogers, Commander of the U.S. Cyber Command and Director of the National Security Agency, in testimony before the House Permanent Select Committee on Intelligence in November 2014, noted, "There shouldn't be any doubt in our minds that there are nation-states and groups that have the capability to do that, to enter our systems...and to shut down...our ability to operate our basic infrastructure, whether it's generating power…moving water and fuel…"[102]

Another effective form of coordinated cyber attack is through the use of a botnet.[x] The Mirai botnet, which involves a global network of infected IoT devices, was used to attack multiple targets on October 21, 2016.[103] This was the largest recorded distributed denial-of-service attack in history. Attacks against Internet systems that support the U.S. power grid, like the Mirai botnet attack, are of significant concern. In most cases, IoT devices are easier to infect than traditional computer systems due to the lack of embedded security and the limited ability to patch known vulnerabilities. With the rapid deployment of IoT devices worldwide, including smart printers, home routers, monitors, and cameras, as well as thousands of others, the opportunity for hackers to disrupt the flows of electricity is growing significantly.

The reliance of our critical energy infrastructures on electricity places a very high premium on a reliable, modern, and hardened electric grid, as well as our efforts to understand, develop, and evolve our emergency response capability to address ever-changing and evolving cyber threats. As a result, electric utilities face significant challenges in securing their IT and OT networks and systems from many cyber attack vectors (Figure 1-15). Utilities also depend on each other; large and small public and private utilities need strong cybersecurity techniques and processes. Given that "systems are only as strong as their weakest links,"[104] sector-wide improvements in grid security will be essential and require collective action both within the industry itself and with government.

[x] A botnet is an interconnected network of computers infected with malware without the user's knowledge and controlled by cyber criminals. They're typically used to send spam emails, transmit viruses, and engage in other acts of cyber crime.

Figure 1-15. Example Cyber Attack Vectors for an Electric Utility[105]



There are many ways to communicate with a control system network and components using a variety of computing and communications equipment. Key vulnerabilities include unpatched networks, unvetted vendor access, access to the public Internet, and insider threats.

Homeland Security Requires a Resilient Power Grid

DHS lists five basic missions in its "2014 Quadrennial Homeland Security Review," three of which directly relate to the electricity system and the other critical infrastructure sectors that depend on it: preventing terrorism and enhancing security, safeguarding and securing cyberspace, and strengthening national preparedness and resilience.[106]

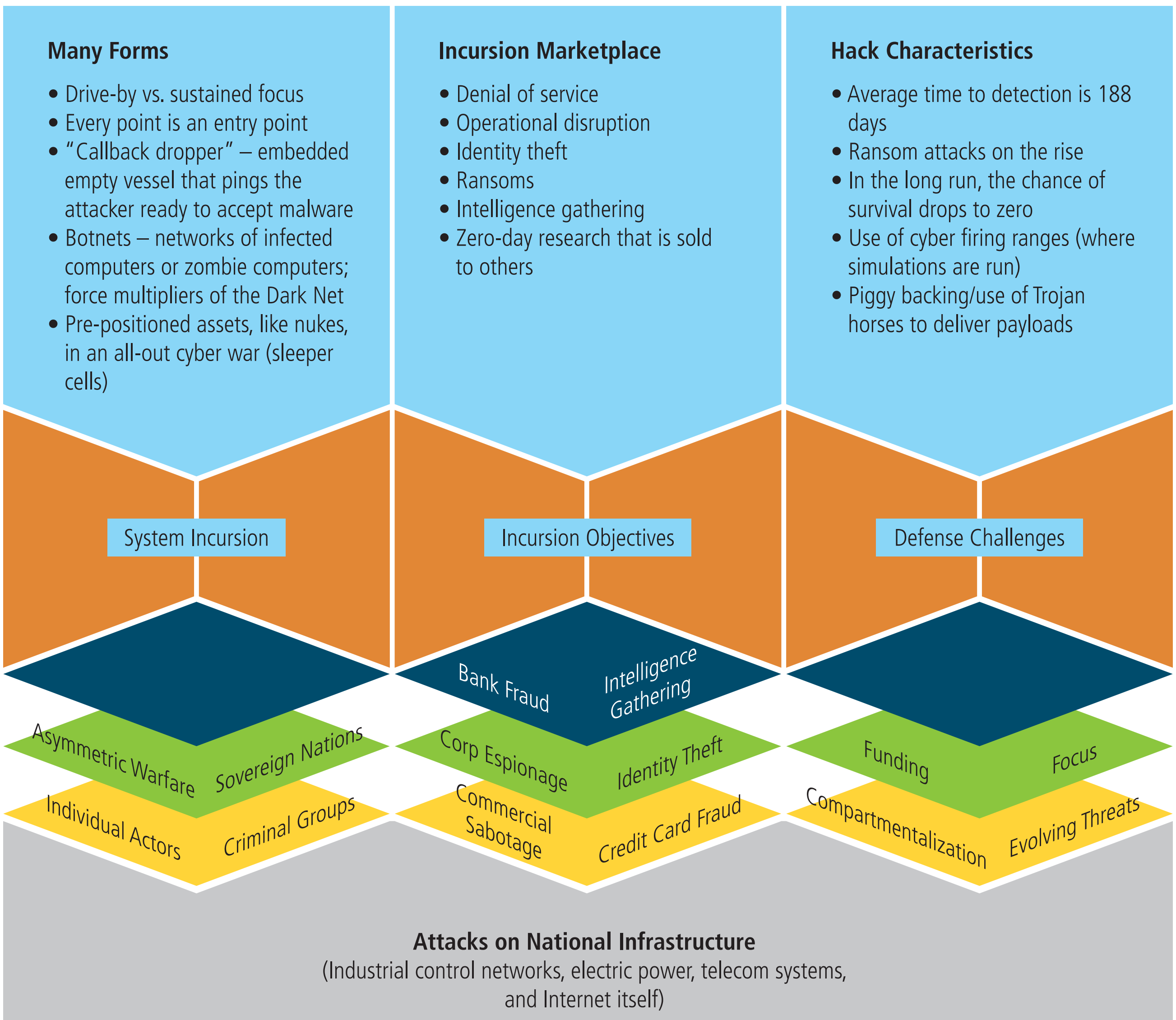
The operational components of Federal and state homeland security agencies are heavily dependent on electric power to function. The Customs and Border Protection (CBP) agency within DHS offers a case in point. To secure the United States across roughly 8,000 miles of land and coastal borders—while simultaneously ensuring a smooth flow of legal trade and travel from the borders through the country's interior—CBP utilizes a vast network of electricity-dependent facilities, sensors, and other operational infrastructure. Radiation portal monitors, for example, are deployed by CBP nationwide (at seaports, land-border ports of entry, and other locations) to safeguard the United States from nuclear devices and dirty bombs.[107] The monitors and networks to which they are linked rely on electricity to function.

Other components of the DHS network, especially the Transportation Security Administration, are equally reliant on electric power to conduct their operations. This is also the case for homeland security agencies and emergency operations centers for state, local, tribal, and territorial governments, which typically have emergency power generation capabilities that will be at increasing risk (in terms of generator burnout and fuel resupply) if long-duration, wide-area power outages occur.

Catastrophes caused by human or natural hazards entail twin challenges for homeland security, both of which will place a premium on grid resilience. First, as revealed in the Clear Path IV and Cascadia Rising exercises in 2016, severe earthquakes and other catastrophic events will pose immediate threats to public health and safety as water and wastewater systems, hospitals, and other critical assets are damaged and lose power. Second, response and recovery operations will be disrupted unless electricity is available to help support the large-scale logistics and transportation operations (including for mass evacuation) that such events will require. Most critical facilities have backup power. However, providing for sustained resupply of fuel for backup generators will become increasingly difficult in long-duration outages, especially in earthquakes or other events that severely disrupt transportation infrastructure, fuel supply chains, and communications.

Traditionally, grid reliability has mainly focused on the physical aspects of the electricity system. Physical systems are impacted by intentional acts of vandalism or attempts to cripple equipment that is critical for electricity service delivery. Growing digitization and reliance on data are making information infrastructure increasingly important to grid reliability as well. Information or cyber systems are significantly more complex from a threat-mitigation perspective; the incursion pathways are more diverse and evolve rapidly, as do attack objectives that can range from intelligence gathering to intentional destruction of grid integrity and operations capability. Figure 1-16 below summarizes these more-complex cyber challenges to the reliability of the grid.

Figure 1-16. Summary of the Cybersecurity Characteristics and Risks Confronting Smart Grid Deployment



Cyber threats have different objectives: typically, incursions by sovereign attackers are warfare-oriented whereas incursions by groups and individuals are driven by pecuniary interests, such as corporate espionage, credit card fraud, and ransom. Sovereign and non-sovereign hacking exhibit similar characteristics and patterns, which inform efforts to defend against attacks. Note: This figure is intended to be illustrative, not comprehensive.

Electricity Has Significant Value for National Defense

The Department of Defense (DOD) is the largest customer of the electric grid in the United States, a system that is largely owned and operated by the private sector. DOD uses electricity to execute the Armed Services' mission-essential functions by energizing the systems that fuel trucks, tanks, and ships; powering the heating, ventilation, and air conditioning systems and other installation infrastructure necessary for military bases to function; and supporting a wide range of other defense operations and assets essential for mission assurance. The degree to which electricity is mission-critical for DOD elevates the level of resilience necessary beyond what may be deemed sufficient for market purposes.

The growing national security implications of the U.S. electricity grid have inspired new laws and regulations to adapt to this imperative and evolving threat landscape. Presidential Policy Directive (PPD) 21 advances a unity of effort to strengthen and maintain secure, functioning, and resilient critical infrastructure focusing on all hazards on both physical and cyber systems. The critical role of electricity to the Nation's defense was also recognized in the Fixing America's Surface Transportation Act of 2015 (commonly known as the FAST Act). Section 61003 of the FAST Act requires the Secretary of Energy, in consultation with other appropriate Federal agencies, to identify facilities in the United States that are (1) "critical to the defense of the United States" and (2) "vulnerable to a disruption of the supply of electric energy provided to such a facility by an external provider."[108]

Electricity is especially vital for powering defense networks and enabling broader command, control, and communications functions. DOD's 2015 "Cyber Strategy" highlights the role of a "wired" world, the essential role of electricity as an enabler of these connections, and the vulnerabilities this dependence creates. The strategy notes that, "DOD's own networks are a patchwork of thousands of networks across the globe, and DOD lacks the visibility and organizational structure required to defend its diffuse networks effectively… DOD relies on critical infrastructure across the United States and overseas for its operations, yet the cybersecurity of such critical infrastructure is uncertain."[109]

The Defense Science Board in 2008 noted that "DOD's key problem with electricity is that critical missions, such as national strategic awareness and national command authorities, are almost entirely dependent on the national transmission grid."[110] This dependence on the grid—which continues today—means that DOD faces many of the same challenges faced by all electricity customers. In 2015, DOD facilities experienced approximately 127 utility outages that lasted 8 hours or longer, an increase from 114 events in 2014.[111] Nearly half of the outages were caused by weather, while the other half were caused by equipment failure. DOD's 2015 "Annual Energy Management Report," in discussing reliance on commercial power supplies, noted that, "DOD recognizes that such events could result in power outages affecting critical DOD missions involving power projection, defense of the homeland, or operations conducted at installations in the U.S. directly supporting warfighting missions overseas."[112]

Since the Defense Science Board's 2008 study, military bases and defense communications networks have taken aggressive actions through a broad range of initiatives to strengthen their ability to operate on emergency power if blackouts occur, including providing backup generation at critical facilities; developing priority relationships with utilities; and building alternative electricity supply configurations, such as microgrids. Improvements in grid resilience can greatly enhance the military's ability to carry out its missions, especially if resilience initiatives are focused on supporting especially critical defense facilities and functions.

Onsite backup generation is DOD's primary method for sustaining operations during grid outages. According to DOD in 2011, most facilities use diesel generators to support operations and critical missions, with enough fuel to sustain basic functions for 3–7 days or more at many installations.[113] Improvements in grid resilience can greatly enhance the military's ability to carry out its missions. For longer-duration outages, however, broader grid resilience initiatives will be essential to improve mission assurance. The longer an outage, the more cascading the effect, with interdependent systems increasingly implicated. After 7 days without electricity generation, the broader impact of defense systems dependent on electricity becomes a concern, including water, fuel, and telecommunication systems. DOE works with DOD to develop backup power generation to support the interdependent systems that rely on electricity. DOD is supporting DOE in developing ways to ensure the resilience of power transformers and other critical equipment. DOD is also strengthening collaboration with utility providers, and state and local emergency management agencies remain a central focus to enhance the resilience and rapid restoration of commercial grid infrastructure that supports mission-critical installations and facilities.[114]

Backup Power for Security

In 2011, the Department of Energy and the Department of Defense announced collaboration on 18 fuel cell backup power generation projects at eight U.S. defense installations. Compared with diesel generators, which are often used for backup power, fuel cells use no petroleum, are quieter, require less maintenance than either generators or batteries, and can easily be monitored remotely to reduce maintenance time. These projects address interdependencies that are at risk the longer the duration outage, but provide backup power to computing, telephone, and lighting functions of the military installations they serve.

Strengthening the resilience of the electricity system not only limits the disruptive effects of adversary attacks on DOD mission assurance—it can also reduce the risk of certain types of attacks occurring in the first place. Resilience initiatives can help strengthen "deterrence by denial." By improving the ability of electricity systems to survive cyber and kinetic attacks, and accelerating power restoration when blackouts do occur, resilience projects can raise an adversary's uncertainty as to whether an attack will achieve the intended consequences. That increased uncertainty can help reduce the potential attractiveness of such an attack—especially if the adversary believes that the United States can effectively respond if an attack occurs. In noting the importance of bolstering deterrence by denial, the Obama Administration's "Report on Cyber Deterrence Policy" calls for "building strong partnerships with the private sector to promote cybersecurity best practices." The report also recommends measures to "architect resilient systems that recover quickly from attacks" and "lend credibility to national efforts to increase network resiliency."[115]

DOE's Growing Role in Protecting the Electricity System as a Critical National Security Asset

DOE's role in addressing the electricity system as a critical component of national security is growing as the threat landscape has evolved. PPD 21 establishes a policy framework and unity of effort to strengthen and maintain secure, functioning, and resilient critical infrastructure focused on all hazards. Under PPD 21, DOE is identified as the sector-specific agency for energy, making DOE the lead Federal interface with energy sector infrastructure owners and operators. Responsibilities also include supporting infrastructure protection efforts within the sector and incident management. As such, DOE leads the Federal Government's Emergency Support Function #12, which is designed to facilitate the reestablishment of damaged energy systems and components. Finally, Congress passed the FAST Act in 2015. The FAST Act includes actions to improve the security and resilience of electricity infrastructure. One of the most important measures provides the Secretary of Energy with broad new authority to address grid security emergencies. "Grid security emergency" is defined to include a physical attack, "a malicious act using electronic communication or an electromagnetic pulse, or a geomagnetic storm event."[116] In the FAST Act, DOE is the statutorily designated sector-specific agency for electricity sector cybersecurity.

The FAST Act also gives new authorities to the Secretary of Energy to protect and restore the reliability of critical electricity infrastructure or defense-critical electricity infrastructure during a cyber, physical, electromagnetic pulse, or geomagnetic disturbance emergency. In addition, the Act gives the President authority to act if there is "imminent danger" of such an attack. This requires constant monitoring and updating of information, as cyber threats are evolving. DOE, as the lead agency on cybersecurity for critical electricity infrastructures, must maintain ongoing capabilities to fulfill a critical advisory role for the President about imminent dangers, as well as to respond to actual emergencies under the new authorities in the FAST Act. Finally, the interdependencies between electricity and natural gas are a growing national security concern; maintaining information on—and ongoing situational awareness of—natural gas infrastructures sufficient to meet DOE's statutory requirements and responsibilities under the FAST Act is essential.

DOE's organic statute—the DOE Organization Act—addresses energy emergencies in its purposes section as "[facilitating] the establishment of an effective strategy for distributing and allocating fuels in periods of shorty supply and to provide for the administration of a national energy supply reserve."[117] This statute, passed in 1977, does not contemplate cybersecurity, electromagnetic pulses, or geomagnetic disturbances; the issues raised in PPD 21 and Emergency Support Function #12; and those addressed in the FAST Act. These issues that have evolved over time, combined with the growing importance of electricity to our national security, constitute a new broad and complex mission for DOE. Given the critical nature of these issues and this mission, adequate resources and appropriate organizational structures within DOE are essential. This could be addressed through a stronger relationship between DOE and FERC.

The Federal Role in Modernizing and Transforming the Grid

The Federal Government is facilitating the transition of the electricity system via avenues that include regulation, procurement, RDD&D, taxation, and the utilization of it convening powers. In the 21st century, the electricity system will still be composed of a diverse mixture of actors in regulated and competitive environments, but will include an expanded array of technologies and actors.

The Electricity System and the Role of the Federal Government

The Federal Government and U.S. electricity system have a complex and longstanding relationship that has enhanced the Nation's economy, security, and environmental sustainability. This relationship is forged through legislative and administrative actions that cover issues related to markets, financing, environmental and health impacts, and workers' health and safety.

The earliest Federal intervention into the electricity system was the encouragement of utility interconnections during World War I to better supply surging electricity demand. The Federal Power Commission (FPC), the first Federal agency with regulatory authority over aspects of the Nation's electricity industry, was created in 1920 by the Federal Water Power Act to license hydroelectric projects on Federal lands or navigable waters. The powers of the FPC were expanded by the Federal Power Act of 1935 to include the regulation of wholesale sales and transmission of electricity in interstate commerce. The Public Utility Holding Company Act of 1935 charged the Security and Exchange Commission with rationalizing the corporate structure of the electricity industry, which had become very concentrated in a small number of holding companies.

During the Great Depression, the Federal Government developed numerous hydroelectric facilities to harvest America's vast hydroelectric potential. This development resulted in the formation of Federal entities to market and transport that power, including the Bonneville Power Administration and the Tennessee Valley Authority. The Rural Electrification Administration, created by the Rural Electrification Act of 1936, gave loans and helped rural organizations develop electric cooperatives, many of which received power from the various Federal hydropower projects.

The Federal Government's role in promoting the science of producing electricity began with nuclear energy. The development of nuclear energy was a side benefit of the weapons program. The Nation's system of National Labs also grew out of the weapons program and has provided useful research to the industry ever since. Development of nuclear power was aided by the Price-Anderson Nuclear Industries Indemnity Act of 1957, which limited liability of commercial reactors and thereby facilitated their inclusion into the utility generation mix. The Federal Government's role in nuclear energy also included licensing nuclear plants with appropriate environmental review.

The Electricity System and the Role of the Federal Government (continued)

The electricity industry is subject to a wide variety of environmental laws, covering air and water pollutants as well as the disposal of solid wastes associated with electricity production. The focus of environmental laws has changed over time. For example, initial concerns over air quality focused on "criteria" pollutants such as particulates, nitrogen oxides, and sulfur dioxide, and then expanded in 1990 to pollutants causing acid rain. More recently, the Environmental Protection Agency has promulgated health-based regulations on mercury emissions and adopted regulations on greenhouse gas emissions that cause global warming.

The Federal Government has played an important role in changing the nature of electricity markets. The Public Utilities Regulatory Policies Act of 1978 required utilities to purchase power from non-utility generators, at their avoided costs, thereby creating new markets for independent generation. These markets were further enhanced by provisions of the Energy Policy Act of 1992, as well as by regulations promulgated by the Federal Energy Regulatory Commission (FERC), which provided transmission access for wholesale market participants. Ultimately, the move to competitive wholesale power markets enabled retail competition policies—allowing end-use customers to select among competing electricity suppliers—adopted by some states. Increasingly, FERC (the successor to the FPC) has recognized the need to protect customers from the exercise of market power by policing anticompetitive behavior in the organized markets.

As the markets have transformed, the Federal Government has continued to lead and participate in market transformations. The Department of Defense has recognized the important role of renewable energy in achieving its mission of protecting the American people. The Department of Homeland Security is playing an important role in increasing cybersecurity and physical security. The Department of Energy is playing an important role as a facilitator and leader of research on the future of the grid and ways to remove technical impediments to getting there. The National Institute of Standards and Technology is developing standards to enable a 21st-century grid. FERC is exploring market rules that will enable participation of a broader array of resources, as well as many customer-sided options.

Electricity Innovation Is Essential

The United States has been a global leader in innovation, and technology development has proved to be one of the great engines of our economy. Innovation investments directly expand the pipeline of new technologies, reduce technology costs, and mitigate risks of new technologies or systems. These benefits, in turn, reduce the cost of policies and incentives[118] and allow decision makers in both government and the private sector to consider options that would otherwise not be available.

The Federal R&D portfolio is one of the most significant contributions to our energy transition. Achieving a clean, flexible, reliable electricity system will require constantly improving the cost and performance of our energy technologies. R&D, coupled with demonstration and deployment (i.e., RDD&D), creates a 'technology push' that reduces the cost of the 'policy pull' generated through regulatory, tax, environmental, and other policies. Current levels of Federal support for electricity and other energy-focused research, development, and demonstration need to be substantially increased. Regional variation in innovation capabilities, infrastructure, markets, policies, and resources also point to a need to address electric sector innovation through regional approaches.[119]

Two key examples of expanding Federal RDD&D investment in the electricity sector are Mission Innovation and DOE's GMI. As noted, DOE's GMI is a crosscutting RDD&D effort to generate technologies that measure, analyze, predict, protect, and control the grid of the future. These technologies are needed to integrate conventional generation, renewable generation, and energy storage; enable smart buildings and end-use devices; and ensure that the grid is resilient to growing physical, cyber, and extreme weather threats. Mission

Innovation is an effort by 22 countries and the European Union—spearheaded by the United States and announced at the Paris Climate Summit in 2015—to dramatically accelerate public and private global clean energy innovation, including doubling the public-sector investment in clean energy RDD&D over 5 years.

Jurisdictional Relationships and Limitations

Responsibility for regulating and overseeing the numerous actors that comprise the electric power industry is vested in multiple government levels and agencies, and new technologies are putting pressure on traditional jurisdictional boundaries. Regulatory authorities span Federal, state, local, and tribal levels. At the Federal level, FERC is responsible for regulation of transmission and wholesale sales in interstate commerce. In addition, other Federal authorities are involved with various aspects of regulation or oversight, including DOE, the Environmental Protection Agency, Department of Justice, Securities and Exchange Commission, Commodity Futures Trading Commission, Department of the Interior, Department of Agriculture, Automated Commercial Environment, and Nuclear Regulatory Commission, among others. Collectively, they oversee many industry actors. Responsibilities are wide-ranging and relate to environmental protection, land use, anti-trust protection, and transmission siting. Congress passed legislation in 2005 giving FERC oversight responsibility for mandatory reliability standards and authorized the agency to partially certify an electric reliability organization to develop and enforce those standards.[120] FERC must approve a reliability standard before it is enforceable. FERC certified the North American Electric Reliability Corporation, a nonprofit corporation, as the electric reliability organization.

In each state, regulatory power is vested with the state public utility commission for regulation of the investor-owned utilities within its state boundaries (and certain public power and cooperative utility activities in some states). Additionally, state policymakers (governors and legislatures) establish laws that industry actors must abide by and that the public utility commissions carry out. State environmental/energy authorities carry out relevant Federal and state legislation and review the environmental impact of certain industry activities within the state. They also control in-state siting of generation and transmission, although the Energy Policy Act of 2005 establishes a significant role for DOE in transmission siting. Local authorities typically include the local governing body of a city, town, or county, or the elected or appointed boards that oversee public power or cooperative electric utilities. Tribal governing bodies are entities that oversee a range of electric industry activities that occur on tribal lands.

The current jurisdictional divide of regulatory authority between the Federal Government and the states, established in the Federal Power Act and clarified by subsequent Supreme Court and lower court decisions, is the result of the evolution of a regulatory structure; in general, Federal regulators have authority over the bulk power system and wholesale electric sales in interstate commerce while State and local regulators have oversight of the distribution system and retail sales. This division of authorities between the Federal Government and states, as written in the Federal Power Act, has been described as a "bright line"; this bright line is, however, becoming increasingly hazy as new technologies and services create more two-way connections between the transmission and distribution systems.

Moreover, the structure of the industry has changed from one primarily characterized by vertically integrated monopolies operating under cost-of-service regulation to one characterized in some locations by significant wholesale and retail competition among many diverse entities. These changes in technologies and the overall structure of the electricity industry can create jurisdictional uncertainty and market misalignment.

The operational characteristics and attributes of new and emerging energy technologies do not fit neatly into existing jurisdictional divisions. As noted, DG technologies have enabled two-way power flow, preventing a simple "hand off" of jurisdiction from Federal to state regulation as electricity flows (and increases or decreases in voltage) from generation through delivery to ultimate consumption. Instead, new DER (including energy storage) can be interconnected to either the FERC jurisdictional high-voltage transmission grid or the state jurisdictional low-voltage local distribution system (or behind the customer's meter). In addition, these resources, along with the other new and advanced technologies noted above, can provide (or enable DR that can provide) several kinds of wholesale and retail grid services, with benefits that extend across the traditional generation, transmission, and distribution classifications.[121]

The scale and scope of the transition already underway also requires the co-evolution of the Federal role; this installment of the QER (i.e., QER 1.2) will therefore consider the Federal role in this transition. The Federal role merits evaluation in terms of the efficiency of markets and rate structures in incenting clean, reliable, and affordable power; emerging technical and operational issues concerning grid reliability, resilience, and flexibility; and the role of institutional structures, including Federal, state, and local jurisdictional boundaries. Key issues for this evaluation include actionable roles the Federal Government should play in facilitating sector transition and whether new responsibilities should be established to ensure desired outcomes.

The Federal Government is facilitating the transition to the 21st-century electricity system by convening diverse stakeholders both formally and informally, managing critical activities concerning an emergency response, collecting and disseminating data, procuring power and selling it through the Power Marketing Administrations, supporting financing of energy projects through loan guarantees, and funding the world's largest Federal energy R&D portfolio.

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Chapter II

MAXIMIZING ECONOMIC VALUE AND CONSUMER EQUITY

Technology-enabled changes on both the consumer and utility sides of the electric meter are creating significant economic value for the Nation's electricity consumers. Technology is also altering the role of consumers and their relationship with utilities and related service providers. These changes are creating new challenges in rate design, the role of markets, and Federal and state jurisdictional roles; enabling new business models; and creating electricity end-use and grid-management opportunities. They could also have disproportionate impacts—both positive and negative—on vulnerable populations and communities.

FINDINGS IN BRIEF:
Maximizing Economic Value and Consumer Equity

- Advanced metering infrastructure has had a profound impact on the nature of interactions between the electricity consumer and the electricity system, allowing a two-way flow of both electricity and information and enabling the integration of assets behind the meter into the larger electric grid.
- Interconnection standards and interoperability are critical requirements for seamless integration of grid-connected devices, appliances, and building energy-management systems, without which grid modernization and further energy efficiency gains may be hindered.
- Evolving consumer preferences for electricity services are creating new opportunities.
- The convergence of the electric grid with information and communications technology creates a platform for value creation and the provision of new services beyond energy.
- There is enormous potential for electric end-use efficiency improvement based on (1) technical analyses, and (2) the differences in energy efficiency performance between states and utilities with and without ambitious electric end-use efficiency policies and programs.
- Tribal lands have the highest rates of unelectrified homes in the contiguous United States and Alaska. The extreme rurality of some tribal communities coupled with high levels of poverty present an economic challenge for the electric utilities trying to serve them.
- Optimization of behind-the-meter assets will require the design of coordination, communication, and control frameworks that can manage the dispatch of these devices in a way that is both economical and secure, while maintaining system reliability.
- Mobile, internet-connected devices foster new ways of consumer engagement, as well as enable consumers to have more efficient and real-time management of their behind-the-meter assets.
- Consumers and third-party merchants who produce electricity can provide economic, environmental, and operational benefits.
- New grid services, modern technologies, and evolving system topologies and requirements are straining traditional methods of valuation. Appropriate valuation of the grid services by various technologies is technically and administratively challenging, and it may depend on spatial and temporal variables unique to different utilities, states, and regions.
- Currently, about 90 percent of residential, 60 percent of commercial, and 30 percent of industrial energy consumption are used in appliances and equipment that are subject to Federal minimum efficiency standards implemented, and periodically updated, by the Department of Energy. Between 2009 and 2030, these cost-effective standards are projected to save consumers more than $545 billion in utility costs, reduce energy consumption by 40.8 quads, and reduce carbon dioxide emissions by over 2.26 billion metric tons.
- Miscellaneous electric loads—devices that are often inadequately addressed by minimum standards, labeling, and other initiatives—are expected to represent an increasing share of total electricity demand, particularly for the residential and commercial sectors.
- Connected devices and energy-management control systems are decreasing in cost and improving in functionality, although their market penetration is still low, particularly in residences and small-to-medium-sized commercial buildings. These new technologies and systems, as well as the broader ‘Internet of Things,’ provide a wide range of options for consumers to manage their energy use, either passively using automated controls or through active monitoring and adjustment of key systems.

FINDINGS IN BRIEF:
Maximizing Economic Value and Consumer Equity (continued)

- Energy-management control systems with communication capabilities are increasing opportunities for demand response services in support of grid operations. Third-party aggregators and other business models are facilitating the expanded use of demand response, but the regulatory environment remains unsettled in many states.
- Lower-income households use less energy but pay a considerably higher fraction of their after-tax income for electricity services.
- Insufficient broadband access in rural areas could inhibit the deployment of grid-modernization technologies and the economic value that these technologies can create.

Maximizing Economic Value and Consumer Equity

The electricity sector has been an economic engine for the United States for more than a century, providing reliable and competitively priced electricity that is critical for the United States' productivity. The vast majority of American consumers—including households, businesses, and institutions—enjoy reliable and affordable electricity that enables a modern economy and a high standard of living. The United States relies on electricity to illuminate schools, heat and cool homes, power manufacturing facilities, and support nearly all forms of economic activity. Some American households, however, still lack basic access to electricity.

Electricity customers can now both produce and consume electricity. This is fundamentally changing the relationship between the customer and his or her utility from that of a consumer who simply pays for electricity services to a "prosumer"—a customer who can also sell electricity supplies and services to the grid. New technologies that enable the two-way flow of both electricity and information have expanded the value proposition of the grid by enabling the integration of assets behind the meter into the larger electric grid. These consumer assets can provide energy, capacity, and ancillary services, and they have the potential to provide new services in the future.

This changing relationship is further driving the convergence of systems, business models, services, policies, and new technologies through a development/feedback loop. Consumers can now adopt a wide array of technologies and program options. These options include: rooftop solar, electric battery storage, electric vehicles (EVs), grid-controlled thermostats and appliances, allocations from community wind and solar projects, locally produced or 100 percent renewable energy plans, alternative pricing regimes, and demand response (DR) and energy efficiency programs and incentives. Mobile, internet-connected devices foster new consumer-engagement modes and enable efficient and real-time management of behind-the-meter assets. Uptake of these advanced options is limited but rapidly growing. Consumers have great latitude in their level of engagement with electricity technology and programs. In some situations, consumers make a one-time decision to adopt a technology or rate structure, eliminating the need for continuous decision making.

Increasingly, the convergence of the electric grid with information and communications technology (ICT) is creating a platform for value creation and the provision of new services beyond electricity, which may or may not require more consumer engagement. In the last several years, for example, major companies have invested in intelligent thermostat software and hardware products to both manage building temperatures and serve as control centers for smart home platforms.[1] The myriad changes taking place at the consumer level are challenging some electric utilities' business models and forcing them to modernize physical infrastructure to maintain high-quality service. Innovative and potentially disruptive changes for different consumer classes are taking place. Policy makers, utilities, and other stakeholders must consider these changes in order to ensure the continued security, affordability, and environmental performance of the electricity system.

Emerging patterns of asset ownership and consumer behavior are challenging existing regulatory structures, institutions, and utility business models, as well as creating new business opportunities. This, in turn, establishes the need for new designs for integrating information networks with the physical grid; these designs must securely and reliably manage distributed communications, control, and coordination among the various participants and intelligent grid assets. Policies, regulations, and business models could and should support distribution system platforms that aim to maximize the full benefit of consumer assets, while compensating utilities and other service providers, including the electricity consumer, for generation, transmission, storage, distribution, and end-use services. Thoughtful regulation in the electricity sector presents an opportunity to improve service, support technology growth, increase consumer equity, and maximize the grid's value. To ensure the continuous affordability, security, and performance of the electricity system, policy makers, utilities, and other stakeholders must consider the key needs and potential disruptive changes taking place across the range of customer classes.

The 21st-Century Energy Consumer

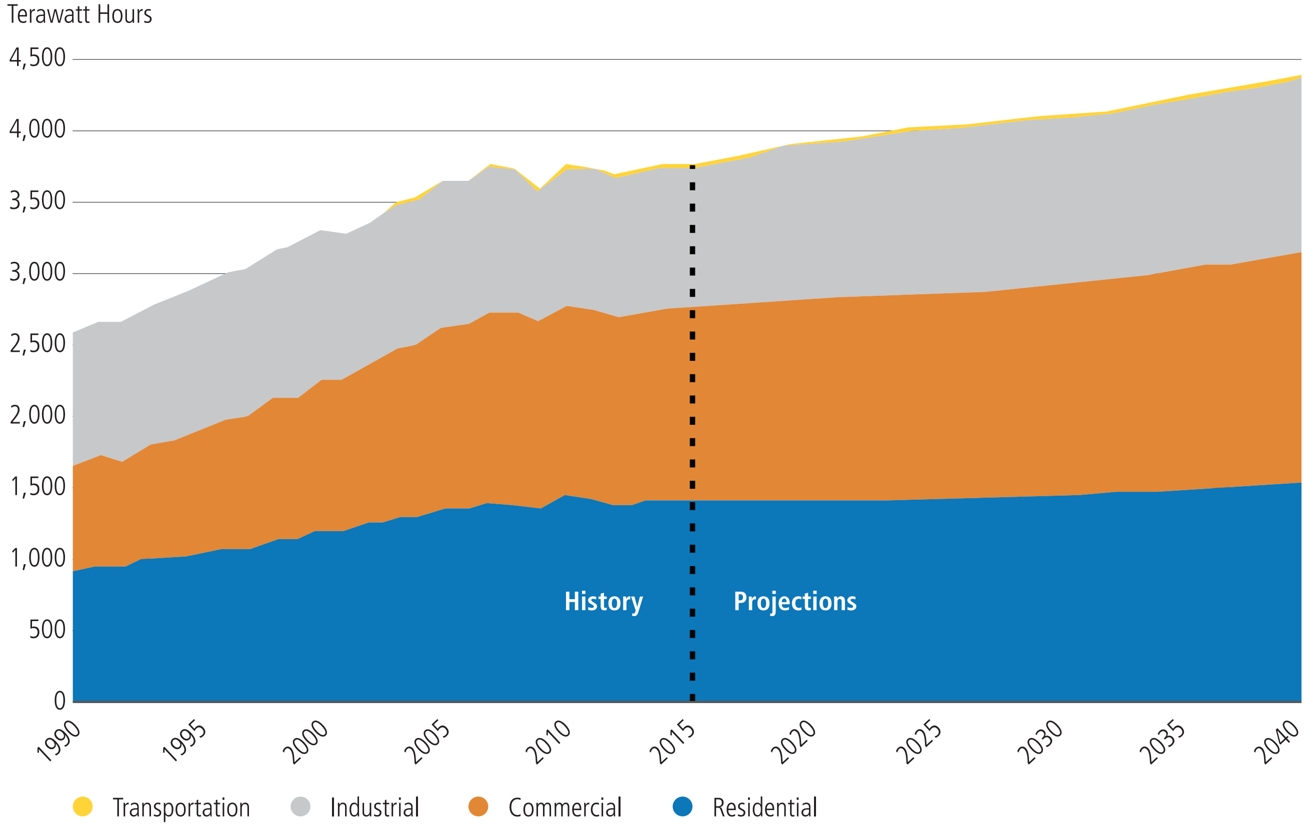
Policy, technology, markets, and consumer preferences are complex, interrelated drivers of change in the electricity system. New policies can influence changes in consumer behavior, like incentives for energy efficiency or distributed solar, or they can stifle consumer choice by limiting competition or raising costs through fees. Conversely, consumer preferences can drive adoption of new technologies or policies. It is hard to separate, for example, the influences of rapidly declining costs for renewable technology from the consumer demands that led state legislatures across the country to adopt renewable portfolio standard (RPS) policies. Regardless of its genesis, the changing nature of the electricity consumer is a powerful force that is shaping the electricity sector. Electricity consumption is an important part of this change (Figure 2-1). The highest growth is projected for the transportation sector—an increase of 134 percent—although it will still make up less than 1 percent of total consumption. Electricity consumption in the residential sector is expected to grow most slowly, by 13 percent. Commercial and industrial electricity consumption are expected to grow by 22 and 32 percent, respectively.[2]

Industrial Consumers of Electricity: Price-Sensitive, Onsite Generation

The industrial sector is extremely diverse, comprising a wide variety of small- to very large-sized facilities. Primary subsectors include manufacturing, mining, construction, and agriculture. Industrial electricity consumption accounts for 26 percent of total annual U.S. electricity consumption.[3]

Industrial electricity sales were relatively flat between 1990 to 2014, due in part to continued improvements in energy efficiency and to the continued shift of the U.S. economy to less energy-intensive industries.[4, 5] Industrial consumers typically use large amounts of electricity and place high value on affordability as electricity costs impact their bottom line. These customers typically pay less for electricity than other consumer classes. Data from the Energy Information Administration (EIA) show a national 12-month rolling average price for industrial customers of 6.74 cents per kilowatt-hour (kWh) versus 12.57 cents/kWh for residential customers and 10.40 cents/kWh for commercial customers as of September 2016.[6] If the industrial customers' electricity needs are large enough, the focus on price can lead them to purchase electricity directly from regional power markets rather than through the local incumbent utility, where the state allows. Large industrial consumers may even be members of a regional transmission organization (RTO) or independent system operator (ISO) to allow them to participate in wholesale markets.

Figure 2-1. U.S. Electricity Consumption Actuals and Projections, 1990–2040[7]



In 2014, the residential sector consumed the most electricity of any sector (1,415 terawatt-hours [TWh], 38 percent of total consumption), followed by the commercial sector (1,358 TWh, 36 percent of total consumption), and the industrial sector (959 TWh, 26 percent of total consumption), with transportation using just 7.6 TWh (less than one percent of total consumption). Overall, electricity consumption is expected to grow by about 18 percent between 2014 and 2040, based on business-as-usual assumptions.

Electricity productivity in the industrial sector (measured in kWh per dollar of output produced) has improved rapidly over the last 15 years,[a] and continued improvement will depend on persistent attention to efficiency. Energy-intensive subsectors (e.g., metals and chemicals manufacturing) represent the greatest opportunities for targeted efficiency improvements. In the manufacturing subsector, which accounts for over 80 percent of total industrial grid-electricity consumption (Figure 2-2), machine drives[b] make up half of industrial electricity use. The next biggest end use, process heating and cooling, makes up just over one-tenth of total industrial electricity use. The focus on price also provides a natural incentive for an industrial customer to self-finance economic energy efficiency measures in order to take advantage of reduced costs and greater productivity.

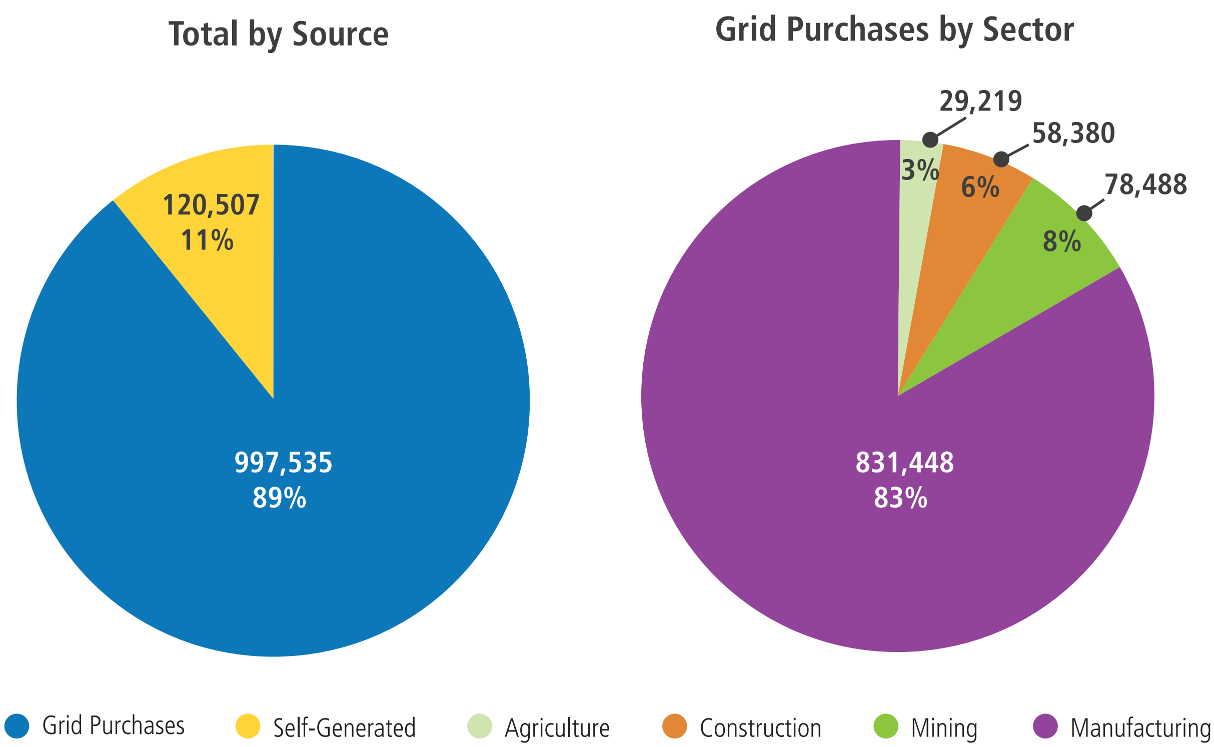
A recent change among some industrial customers, especially among those with retail customers, is the development of corporate sustainability goals. Achieving these goals may involve self-generation, purchase

[a] Electricity productivity, measured as dollars of gross domestic product produced per kilowatt-hour, nearly doubled between 1990 and 2014, while industrial electricity sales were flat.

[b] Machine drives convert electric energy into mechanical energy and are found in almost every process in manufacturing; they comprise motors and the process systems they drive.

of credits, or wholesale power purchases involving low- or zero-carbon generation, such as from renewables (Figure 2-2). For example, General Motors, a very large consumer of electricity, is currently the largest automotive user of solar power and is among the top 25 solar-powered U.S. companies.[8]

Figure 2-2. U.S. Industrial Electricity Consumption, 2014



The chart on the left shows the industrial sector's purchased electricity consumption, combined heat and power self-generation by source. The chart on the right shows purchased electricity by industrial subsector.

For many industrial facilities, energy is not actively managed. While some facilities implement stand-alone energy efficiency projects that save energy, many do not implement these projects as part of a comprehensive strategy to continually improve energy performance. For example, while nearly 30 percent of U.S. manufacturing facilities report setting goals for improving energy efficiency,[10] only about 7 percent of facilities report employing a full-time energy manager. Strategic energy management approaches, such as ENERGY STAR for industrial energy management, ISO 50001, and Superior Energy Performance help individual businesses identify operational efficiency opportunities.[c] Cost-benefit assessments for Superior Energy Performance find annual savings between $36,000 and $938,000, with paybacks of less than 1.5 years for large energy-consuming facilities (those with annual energy costs of more than $2 million.)[11] In its Energy Bandwidth Studies, the Department of Energy (DOE) has identified potential energy savings for selected

[c] ISO 50001 is an international energy management standard, and Superior Energy Performance is a program that helps companies to incorporate ISO 50001 into their production management practices and motivates them to set and reach savings goals. More information on Industrial Energy Management through ENERGY STAR is available at https://www.energystar.gov/buildings/facility-owners-and-managers/industrial-plants.

industrial sectors by calculating differences between typical energy consumption levels for specific processes and lower consumption levels required by state-of-the-art technology, as well as technology currently under research and development (R&D).[12]

DR (shifting or decreasing electricity use in response to time-based rates or other forms of financial incentives) also helps make U.S. manufacturers more competitive. In the PJM Interconnection (PJM) region, large industrial customers often bid DR into the market as a resource.

In addition, industrial combined heat and power (CHP) represents opportunities for near-term solutions to reduce energy intensity.[d] CHP-generating capacity is equivalent to about 8 percent of U.S. generating capacity from utility-scale power plants in 2015.[e, 13] By concurrently producing electricity and heat at the site of use, CHP systems use 25 percent to 35 percent less primary energy than grid electricity plus conventional heating end uses (e.g., water heaters and boilers), with a typical 75 percent overall efficiency versus 50 percent with conventional generation. In regions where the emissions intensity of central electric generation is high, switching to CHP will have the biggest emissions impact. DOE estimates that there is technical potential for roughly 241 gigawatts (GW) of CHP capacity in the United States, including industrial and commercial CHP, as well as waste heat to power.[14]

Overall growth in CHP capacity has stalled since the early 2000s due to upfront equipment costs, technical complexity, and policy changes. There are significant, ongoing deployment efforts to promote this technology, including DOE's CHP Technical Assistance Partnerships,[15] as well as several active state incentives, such as incorporating CHP generation in RPS and utility incentives for CHP systems.[16] The highest number of CHP installations in 2013 and 2014 occurred in states with multi-year CHP-incentive programs, such as New York and California.

Commercial Consumers: Optimizing Building Design, Lighting, and Space Conditioning

There are about 87 billion square feet of commercial space in the United States, spread across more than 5 million commercial and institutional buildings.[17] Commercial electricity consumption accounts for about 36 percent of total U.S. electricity demand. This sector is very diverse and includes office, retail, health care, education, warehouse, and several other building types, ranging in size from a few thousand to millions of square feet per building. Four types of commercial buildings account for more than 50 percent of total delivered electricity consumption—office, retail, education, and health care.[f, 18]

Recent analysis shows that in states consistently adopting the most current versions of model building energy codes, homeowners, building owners, and tenants are projected to save $126 billion on energy bills between 2010 and 2040 if codes continue to be strengthened.[19] Many of the high-efficiency technologies, building envelope designs, and energy-management practices that enable significant energy savings and greenhouse gas (GHG) reductions beyond today's building codes have been demonstrated and are commercially available.

Commercial-sector square footage and energy use has grown steadily, although electricity intensity (kWh/square foot) is improving, largely driven by increases in energy efficiency across end uses. Recent analysis indicates that the major contributing factors to the change in commercial electricity consumption from 2008 to

[d] Within the manufacturing subsector, the Manufacturing Energy and Carbon Footprints analysis estimates that 7,228 trillion British thermal units (Btu), or 51 percent of the 14,064 trillion Btu of total delivered energy to the U.S. manufacturing sector, was wasted as efficiency losses in 2010.

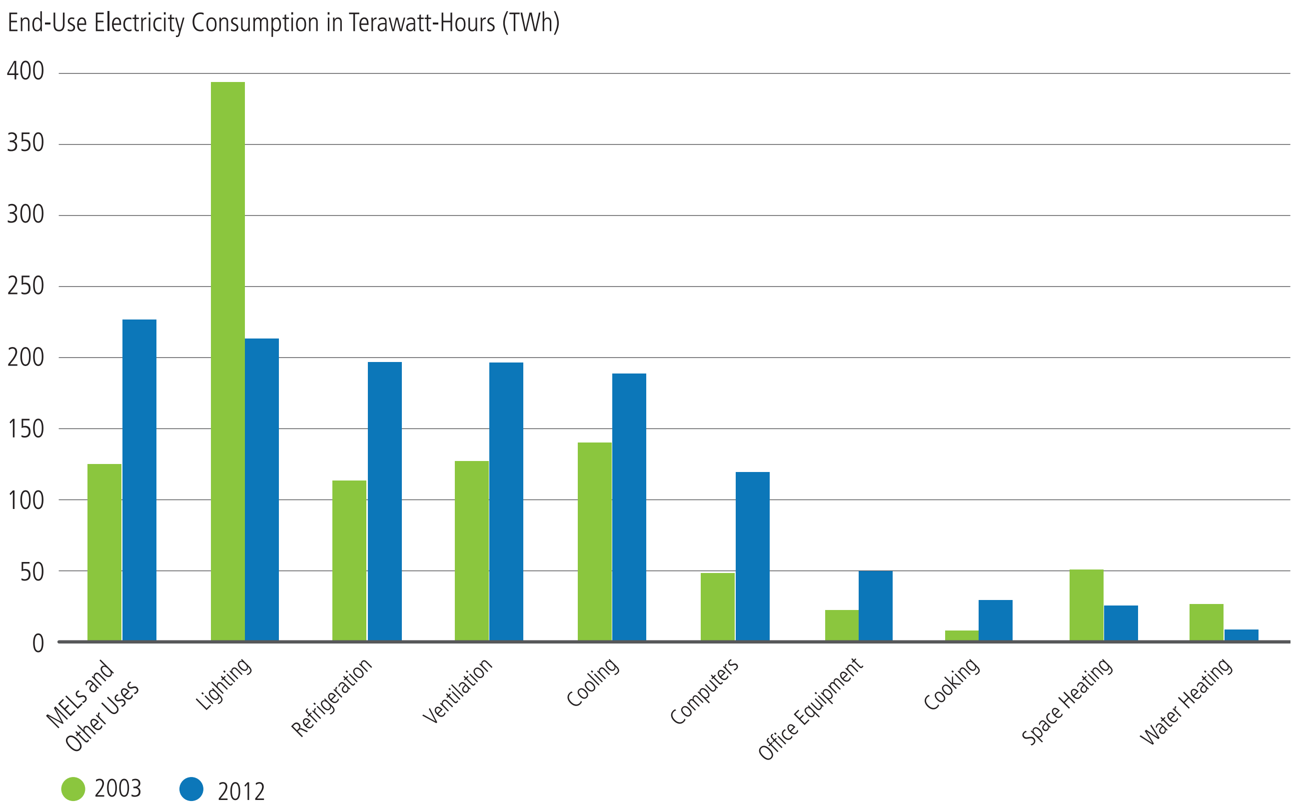
[e] CHP is often considered a form of energy efficiency, but it can also be considered a form of distributed generation.

[f] For a total of 56.4 percent, offices account for 20.4 percent, mercantile (malls and non-mall retail) accounts for 16.6 percent, education accounts for 10.8 percent, and health care accounts for 8.6 percent.

2012 were savings from appliance and equipment standards and utility energy efficiency programs.[20] Moving forward, these efficiency trends will continue to make a significant impact. From 2013 to 2040, commercial end-use intensity, measured in kWh/square foot, is projected to decrease by about 8 percent.[21] This decrease is led by a significant decline in the electricity intensity of lighting,[22] but it is also offset by a significant increase in miscellaneous electric loads (MELs) (Figure 2-3).[g]

The efficiency of most commercial end uses is increasing with the deployment of advanced lighting, space conditioning, electronics, and building designs. The retrofit of existing commercial buildings and the adoption of new energy-management tools are also significantly contributing to meeting environmental goals and reducing consumer electricity costs. The efficiency programs that utilities and Federal, state, and local agencies are now implementing have helped enable these trends.[23]

Figure 2-3. Comparison of Commercial End-Use Electricity Consumption, 2003 and 2012[24, 25]



Consumption across most end uses is increasing, including MELs, refrigeration, computing, cooling, and other uses. Lighting and space-heating consumption have each decreased by about 50 percent between 2003 and 2012.

[g] MELs represent a range of electric loads outside of a building's core end uses of heating, ventilation, air conditioning, lighting, water heating, and refrigeration. Sample MELs include televisions, pool heaters and pumps, set-top boxes, and ceiling fans.

"Dispatchable" Smart, Green Buildings

An important trend with implications for the electricity system is the increasing digitization of commercial office space and the resulting opportunities to use buildings themselves as part of the electric system. Building loads are becoming "dispatchable" by utilizing DR technologies, markets, and the growing industry for peak-load DR through aggregators.[26] A recent report estimates that the global market for building energy-management software will grow from $2.4 billion in 2015 to $10.8 billion in 2024.[27] Energy-management systems are increasingly able to control room temperatures, humidity, ventilation rates, plug loads, and dimmable lights, and in the future, capabilities to control windows and louvers may exist.[28] Similarly, lighting; windows; heating, ventilation, and air conditioning (HVAC) equipment; water heaters; and other building equipment can be equipped with smart controllers and wireless communications capabilities.[29] High-performance building attributes are increasingly factoring into tenants' decisions about leasing space and buyers' decisions about purchasing properties. For both small commercial customers and households, there are information and first-cost barriers that limit penetration of these communicating devices. In 2012, about 70 percent of commercial buildings larger than 100,000 square feet, for example, had some kind of energy management or control system for HVAC, but only about 15 percent of buildings smaller than 25,000 square feet used them.[30]

Meeting Sustainability Goals through Direct Procurement of Renewable Energy

In some states, large electricity consumers are able to purchase electricity from providers other than the local incumbent utility. In recent years, some large commercial customers, particularly those that are consumer-facing, have adopted corporate sustainability goals that include renewable electricity (Figure 2-4). In 2015, corporations (both commercial and industrial) contracted nearly 3.4 GW of renewable energy[31]—up significantly from the 650 megawatts (MW) contracted between 2008 and 2012.[32]

There are several ways in which corporations can voluntarily procure renewable energy, including power purchase agreements (PPAs). In areas where market structures preclude PPAs for direct corporate procurement, some utilities and retail electricity service providers offer green choice or green tariff programs; for example, some energy providers in Texas offer 100-percent wind plans to customers.

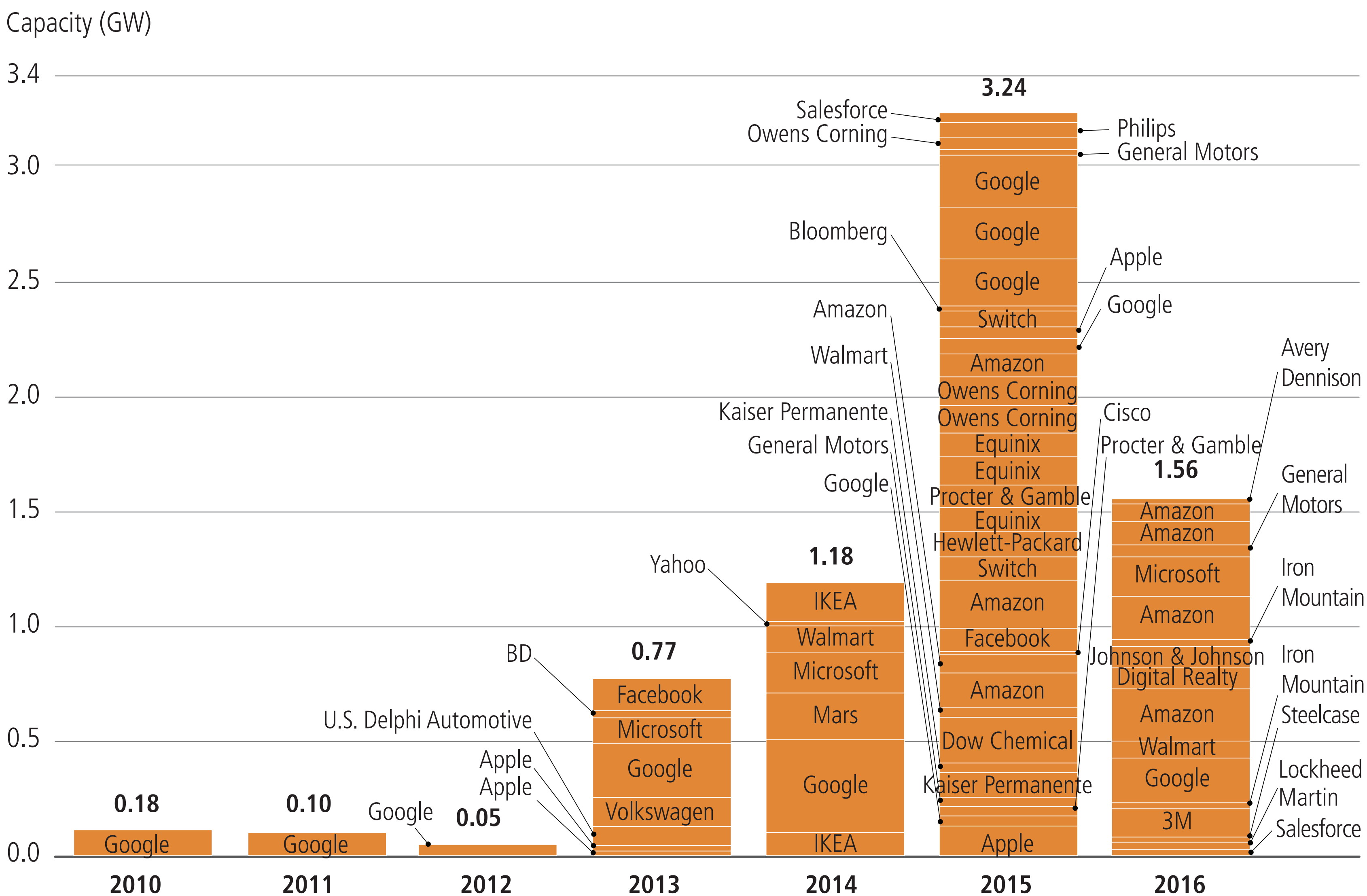
Some companies are going beyond direct purchase of electricity. In 2010, the Federal Energy Regulatory Commission (FERC) granted Google Energy the authority to sell wholesale electricity.[33] In another innovative arrangement, Amazon's cloud computing division, Amazon Web Services (AWS), signed a new type of PPA with Dominion Virginia Power. The agreement allows the utility to manage AWS' existing and future investments in solar and wind projects; charges AWS a retail rate for electricity close to the wholesale rate that their investments earn in the market; and prevents the costs of AWS' renewable energy investment from shifting to other consumers.[34]

Federal Agencies

With more than 350,000 buildings in use, the Federal Government is the Nation's largest energy user.[35] The Federal Government used 947 trillion British thermal units in 2015.[36] Electricity made up 19.9 percent of Federal energy use, behind only jet fuel at 44.2 percent.[37] Most Federal buildings have GHG-reduction goals, and Federal law encourages Federal agencies to implement all cost-effective energy efficiency measures. Federal law also requires agencies to use life-cycle cost analyses when considering building systems.[38]

Executive Order 13514 requires Federal agencies to reduce GHG emissions by 2025 by 40 percent compared to a 2008 baseline. It also requires Federal facilities to meet a 30-percent renewable electricity standard by 2025,[39] and facilities can meet the standard in one of four ways (listed in order of priority) (1) installing agency-funded renewable energy onsite at Federal facilities; (2) contracting the purchase of energy, which includes the installation of renewable energy onsite and offsite at a Federal facility; (3) purchasing renewable electricity; and (4) purchasing Renewable Electricity Credits.[40] Fifteen percent of existing agency buildings must be green buildings, either by number or square footage.[41]

Figure 2-4. Corporate Procurement of Renewable Energy-Based Electricity, 2010–2016[42]

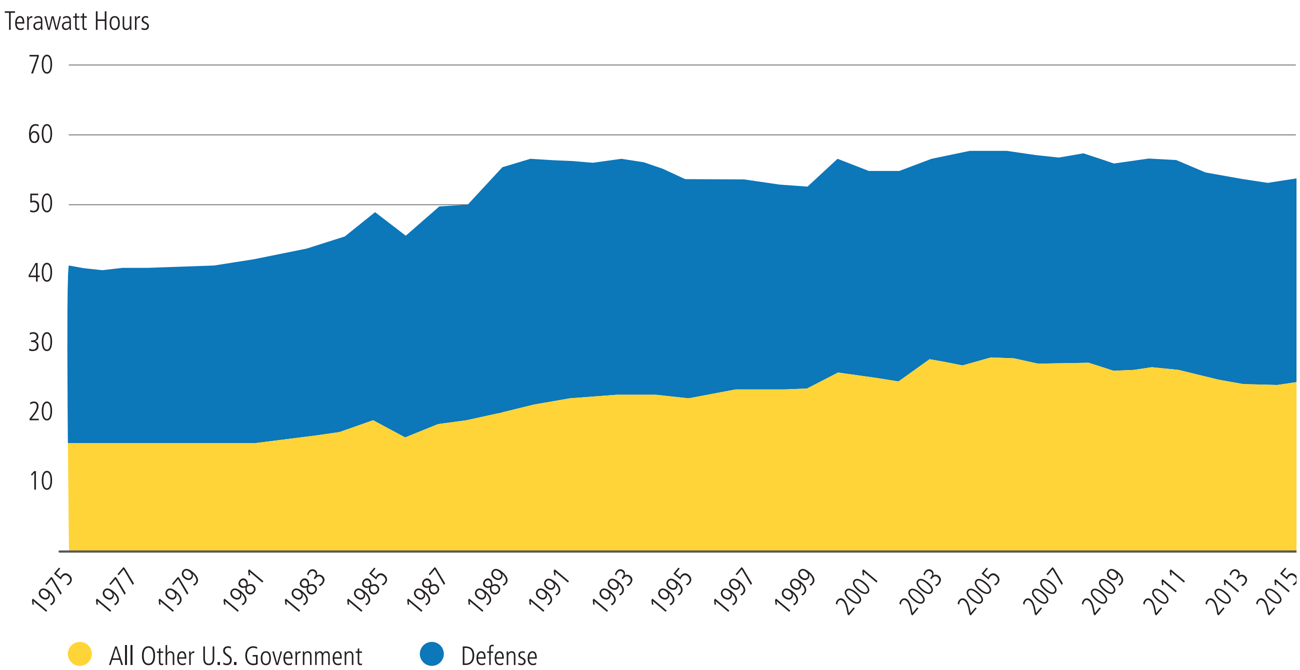


Large corporate customers (including commercial and industrial customers) can specify the type of generation underlying the electricity they consume through power purchase agreements, green tariffs, and direct project ownership. Corporate procurements represent an important new mechanism for developing renewable energy projects. The table illustrates individual procurements; last modified December 15, 2016.

Department of Defense Is Single-Largest Consumer of Electricity

The Department of Defense (DOD) is one of the largest energy consumers in the United States, is the largest customer of the electric grid, and uses more than all other agencies combined (Figure 2-5). DOD requires electricity to support its missions both directly by energizing the facilities and systems that fuel fleets of trucks, tanks, and ships, and indirectly by energizing other supporting infrastructure, such as the communications systems that deliver information across the globe. To ensure it can perform its mission, DOD invests in numerous advanced technologies that improve energy efficiency and increase energy supply resilience; however, it faces many of the same challenges as other public institutions.

Figure 2-5. Electricity Use by the U.S. Government and Department of Defense, 1975–2015[44]



DOD uses more electricity than the rest of the U.S. government combined. This relationship has remained relatively steady for the past 40 years.

DOD has been an early and active user of energy savings performance contracts to implement energy efficiency projects that save money and reduce electricity demand.[h, 45] DOD also pursues renewable energy to advance its energy resilience. Roughly 2 percent of DOD's total energy consumption came from renewable sources in fiscal year 2015. Onsite operational projects (mostly geothermal, biomass, and municipal solid waste) accounted for 82 percent of the Department's renewable energy supply, while purchased renewable energy credits represented the other 18 percent. In 2015, DOD had over 1,390 operational renewable energy projects, compared to 1,130 in 2014.[46] Geothermal electric power is, by far, the most significant renewable energy source in DOD, accounting for over 41 percent of the Department's renewable energy generation portfolio. Biomass makes up about 19 percent, while municipal solid waste, which is used for both electricity and steam production, accounts for 15 percent. There are 810 solar photovoltaic (PV) systems throughout the

[h] An energy savings performance contract is a financial arrangement whereby an energy service company (ESCO) identifies and invests in energy savings investments on behalf of an end user, guaranteeing that the resulting energy cost savings are sufficient to fully pay for the investments over the life of the contract. Additional savings are shared between the ESCO and the end user, and all cost savings after the contract ends accrue to the end user.

DOD system that contribute approximately 13 percent. In October 2016, the U.S. Navy and Sempra Energy opened the 150-MW Mesquite Solar 3 project to supply approximately one-third of the electricity required by 14 Navy and Marine installations—the largest Federal purchase of clean energy in history.[47, 48]

DOD is also exploring cost-effective ways to incorporate microgrid applications to reduce energy demand, increase energy surety, and provide distributed generation (DG) and storage. Smart Power Infrastructure Demonstration for Energy Reliability and Security (SPIDERS) Joint Capability Technology Demonstration (JCTD) is a groundbreaking program designed to bolster the cybersecurity and energy efficiency of U.S. military installations and transfer the know-how to non-military, critical infrastructure.[49] DOD launched the SPIDERS JCTD program in response to growing concern about the military's energy infrastructure's vulnerability to natural disasters and computer-borne cyber attacks, which could impact the grid.

Municipalities, Universities, Schools, and Hospitals

Public and institutional consumers, such as municipalities, universities, schools, and hospitals, often called the MUSH market, are another growing category of electricity customers. These customers, especially cities, are considered to be engines of economic growth as they support large, concentrated populations with complex infrastructure and specific electricity demand needs.[50] While the electricity demand needs of these consumers are vital to economic prosperity and security, the MUSH market often faces constrained maintenance budgets and limited access to capital; public entities are also not eligible for clean energy tax credits that entities with tax liability can use to apply toward certain projects. As a result, these customers take creative approaches to meet all their needs, while acting as the locus of innovation in an array of sectors that drive technological change, including transportation, defense, and public health.

The electricity bill for a municipal government covers electricity for operating municipal buildings, and providing public services like water treatment, street lights, and traffic signals.[51] New equipment and efficiency measures can save energy and reduce carbon pollution, and retrofitted buildings provide healthier and more productive workplaces.[52]

To reduce pollution and save tax dollars, municipal and tribal governments have adopted energy efficiency measures, entered into agreements to purchase renewable energy, and installed their own renewable energy sources. The 30 top municipal and tribal governments in the Environmental Protection Agency's (EPA's) Green Power Partnership (a voluntary program that encourages organizations to use clean energy) used 3.9 billion kWh of clean energy annually, roughly equivalent to the electricity use of 360,000 average American homes.[53] The City of Houston, Texas, was number one on the list, with 951,799,375 kWh in solar and wind energy purchased from Reliant Energy and generated onsite, equivalent to 80 percent of the city government's total electricity use.[54] The City of Detroit is replacing wasteful, high-pressure sodium streetlights, about half of which are no longer working, with modern light-emitting diode (LED) street lighting that will save energy costs and improve reliability and security.[55, 56]

Other cities have developed waste-to-energy projects to dispose of municipal waste while also producing electricity or steam for heating buildings. As of 2013, there were 80 waste-to-energy plants that disposed of 12.9 percent of the Nation's municipal waste while producing 14 billion kWh of electricity—roughly the same amount used by 1.3 million U.S. households.[57]

Updated, networked streetlights can also provide other benefits to city governments, in addition to energy savings. Networked LED systems with wireless internet and sensors can alert management when an outage occurs, monitor traffic or air quality, and publicize the availability of parking spaces.[58] GE's new smart streetlights will combine LED lighting with acoustic sensors to detect and locate gunfire and automatically notify police.[59]

Advancements in ICT are enabling improvements throughout the electricity system, including how city governments use electricity and provide public services. The Smart Cities Initiative, a $160 million program for technology at the local level, has improved the collection, aggregation, and use of data, allowing local governments to better deliver public services.[60] Through the initiative, more than 20 cities are partnering with Federal agencies, universities, and technology companies in research and demonstration projects involving smart energy devices, the Internet of Things (IoT), transportation solutions, and energy efficiency programs.[61] For example, one research award will support research into the integration of self-driving cars and smart buildings, while another will investigate novel approaches to integrating distributed power sources and battery energy storage.[62]

Municipal Water Efficiency Opportunities

Conveyance, initial treatment, distribution, and wastewater treatment all require energy input, and some have potential energy outputs (such as energy from wastewater bio-solids). The national energy demand for drinking water and wastewater treatment increased by more than 30 percent between 1996 and 2013. This increase is primarily due to population growth (about 17 percent) and more stringent water quality regulations, such as the Safe Drinking Water Act.[65, 66, 67, 68] For a typical water resource-recovery facility, electricity accounts for nearly 23 percent of its operating costs.[69]

There are a number of ways to significantly improve the energy efficiency of electric water pumps used in municipal systems through efficiency standards. DOE has regulatory authority over pumps, including water pumps. In 2016, DOE set minimum standards for certain categories of water pumps and the adoption of variable speed drives; DOE required compliance starting in 2020.[i] Moreover, requirements for compliance with these standards could have the ancillary benefit of enhanced data collection on energy use by pumps.[70] Other management techniques to reduce pumps' electricity demand are growing. For example, because water pumps used for irrigation and municipal water systems can be temporarily turned off to reduce load during periods of peak demand, a number of utilities already offer incentives for water system operators to participate in DR programs.

In addition, treatment facilities have numerous opportunities to become net producers of energy.[71] Municipal wastewater contains 5 to 10 times as much chemical and thermal energy as the law currently requires for water treatment to meet discharge standards.[72, 73, 74]

Residential Consumers

The residential sector accounts for about 38 percent of total U.S. electricity demand. Single-family detached homes consume 74 percent of electricity across the Nation's total stock of 113.6 million residences. While residential electricity demand increased between 1990 and 2006, in more recent years, there has been little, or even negative, annual electricity consumption growth in the residential sector. Improvements in the electricity intensity (megawatt hours [MWh]/household) of the residential sector, largely attributed to the increasing efficiency of most end uses, have contributed to this recent low growth.

The number of U.S. households has been increasing, and this trend is expected to continue. Per household, 2040 electricity usage is projected to be lower than 2013—10 percent lower per household, 8 percent lower per capita, and 18 percent lower per square foot. Continued improvements in energy efficiency and other energy technologies, like onsite generation and storage, are likely to accelerate in new and existing homes and across appliances, lighting, water heating, heating and cooling equipment, and electronics, putting downward pressure on load growth. Renewable energy and efficiency programs implemented by utilities and Federal, state, and local governments have played an important role in enabling these trends.

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[i] 10 C.F.R. 429, 10 C.F.R. 431. The Energy Policy and Conservation Act of 1975, as amended, sets forth a variety of provisions designed to improve energy efficiency. Part C of Title III establishes the "Energy Conservation Program for Certain Industrial Equipment." The covered equipment includes pumps.

Energy Management through DR, Automation, and Smart Homes

Since the 1980s, a number of utilities have operated retail DR programs using radio and powerline carrier communications. Now, utilties are also using smart meter-enabled, central air-conditioning and electric water-heater switches. Both electric utilities and private companies now aggregate residential loads in retail and wholesale electricity markets. While it is growing, the widespread and deep use of residential customer loads as part of electric grid operations is still relatively nascent in relation to its potential.

As of 2016, most residential buildings are equipped to automate only a small number of tasks since affordable automation technology, with some exceptions, is not commercially available or widely used. In addition, smart meters, a key enabler of such activities, have only recently been widely deployed and are at an early stage of development for consumers.

Programmable thermostats are widely available and are present in 37 percent of housing units; however, only 53 percent of households with these thermostats use them to lower temperatures during the day, and only 61 percent use them to lower temperatures overnight.[39]

Also, "smart" thermostats, which can learn from occupant behavior and adjust settings to minimize energy use, are now available. These devices can also enable automated DR through a home's smart meter, adjusting thermostats during peak load events to shave usage.[40] Some smart thermostats can now use wireless communications to control appliances and other smart devices within homes; they may even serve as the control platform for "smart homes." Homeowners can also integrate these devices with residential solar output and, along with storage or EVs, use them to react to price signals to optimize EV battery charging and overall system performance. EVs could act as mobile battery resources that consume electricity or provide it back to the grid as energy or frequency management services where incentives exist.[j]

Consumer Preferences for New Technologies and Services

Utilities and other service providers are increasingly segmenting broad consumer classes into smaller, more-specific groups based on preferences for marketing purposes.[k]

Technology itself can help utilities better understand the needs and interests of consumers. Electric utilities are beginning to use "big data analytics" to better meet their customers' needs and deliver services to them.[75, 76] As more residential types emerge, electric utilities and third parties are no longer treating residential customers as monolithic. Utilities are adjusting their product offerings—all of which have implications for the electric power system.

Implications of new technology for the electric power system include the types of generation that are built; how distribution systems are designed and operated; how fast distribution outages are restored; retail rate design and the resulting customer bills; and how utility industry business and regulatory models evolve. A central question for state electricity regulators, consumer advocates, and electric utilities is how to balance the utility's need to recover fixed costs and provide safe, reliable, and affordable energy to all consumers with electricity consumers' small, albeit growing, desire for more products and services.[77]

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[j] Chapter III (*Building a Clean Electricity Future*) discusses EVs and the need for charging infrastructure to provide more charging options to consumers.

[k] See Edison Foundation's Institute of Electric Innovation, "Thought Leaders Speak Out: Key Trends Driving Change in the Electric Power Industry, Volumes I, II, and III," December 14, 2015, June 14, 2016, and December 14, 2016, respectively. http://www.edisonfoundation.net/iei/.

Retail Electric Choice Markets

In the late 1990s and early 2000s, some state legislatures passed legislation opening the retail electricity market to firms beyond the incumbent distribution utility. Currently, 14 states and the District of Columbia have programs that allow end-use customers to buy electricity from competitive retail suppliers.[l, m] Under this structure, the regulated distribution utility still manages and provides the distribution of electricity through wires, with retail marketers procuring and selling the commodity itself. States' retail open-access policies typically apply only to investor-owned utilities, though some states conditionally require it for electric cooperatives as well. States with retail open access typically do not require it for public power utilities, leaving competition policy to their local governing boards. Some states, such as Michigan, cap retail open access as a percentage of electricity sales (i.e., alternative retail electric supplies, besides the incumbent distribution utility, can provide up to 10 percent of retail electric sales).

The outcome of retail electric choice has been mixed. Retail choice has introduced dynamic pricing programs and new services, and it has encouraged the growth of renewable energy. However, electricity prices in areas with retail choice have been more variable and possibly even higher than in areas without it.[n, o] Most states with retail choice also rely on the distribution utility that serves as the default energy commodity provider, with administratively determined rates for customers who choose not to participate in the retail market.

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[l] In 2014, 20 percent of electricity sales (MWh) to ultimate consumers were by competitive retail suppliers. Source: 2016–2017 Annual Directory and Statistical Issue, American Public Power Association, 51, derived from EIA Form 861 data.

[m] Matthew J. Morey and Laurence D. Kirsch, *Retail Choice in Electricity: What Have We Learned in 20 Years?* (Washington, DC: Christensen Associates Energy Consulting LLC for Electric Markets Research Foundation, 2016), v, https://www.hks.harvard.edu/hepg/Papers/2016/Retail%20Choice%20in%20Electricity%20for%20EMRF%20Final.pdf.

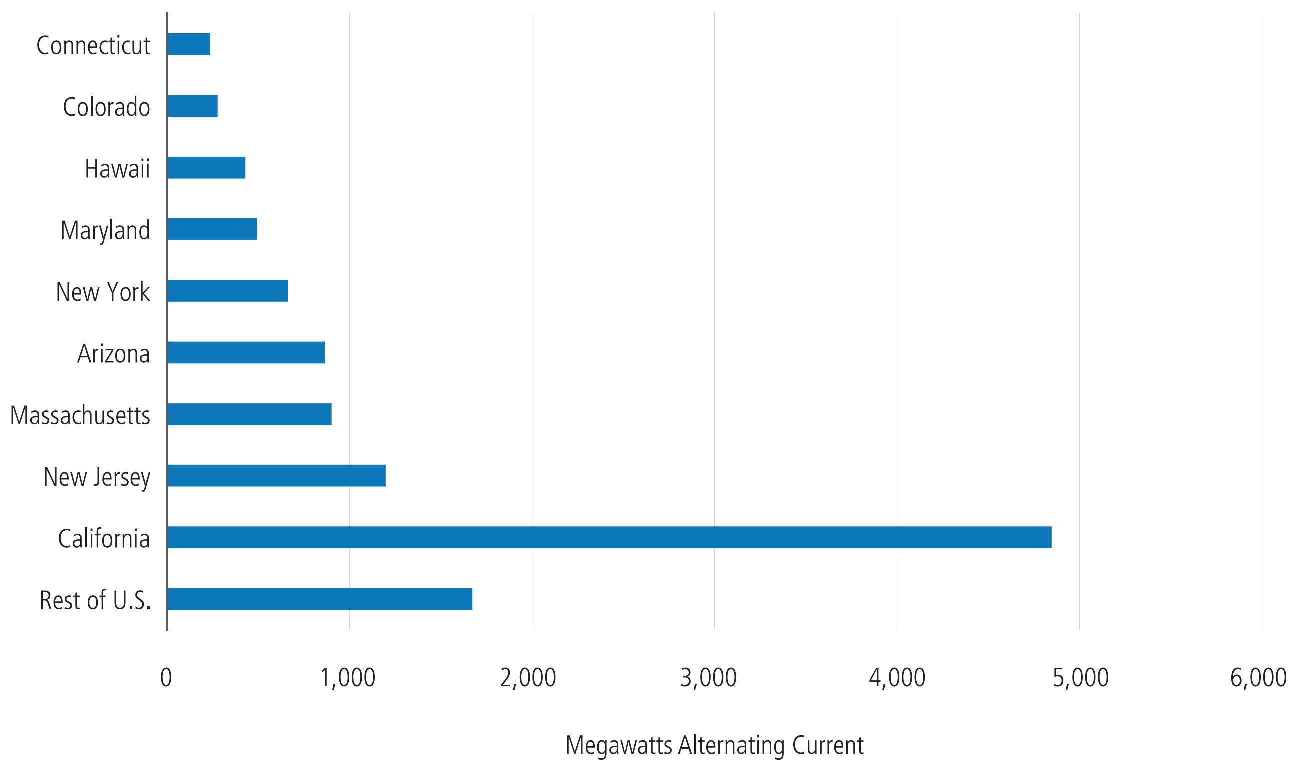
[n] Matthew J. Morey and Laurence D. Kirsch, *Retail Choice in Electricity: What Have We Learned in 20 Years?* (Washington, DC: Christensen Associates Energy Consulting LLC for Electric Markets Research Foundation, 2016), vi, https://www.hks.harvard.edu/hepg/Papers/2016/Retail%20Choice%20in%20Electricity%20for%20EMRF%20Final.pdf.

[o] Severin Borenstein and James Bushnell, *The U.S. Electricity Industry after 20 Years of Restructuring* (Berkeley, CA: University of California, Berkeley, Energy Institute at Haas, May 2015), 18–20, https://ei.haas.berkeley.edu/research/papers/WP252.pdf.

Distributed Generation: A Consumer Choice

In recent years, there has been significant growth in DG, particularly rooftop solar PV, which has been fostered by lower installation and hardware costs and supportive policies, such as net metering (discussed in greater detail later in this chapter), self-generation tariffs, and RPS with set-asides or multipliers for DG.

Figure 2-6. Distributed Solar PV Capacity, Top 10 States, August 2016[78]



Distributed solar PV capacity is unevenly distributed in the United States. As of August 2016, roughly a third of capacity was installed in California, followed by New Jersey and Massachusetts.

Distributed solar PV generating capacity grew by a factor of over 80 between 2004 and 2014,[79] while distributed wind increased by about a factor of 14.[80] The price of installed residential solar PV is projected to fall below $2 per watts of DC in the next 10 years, and distributed solar PV electricity generation is projected to grow by a factor of nearly 19 from 2015 to 2040.[81, 82] Most distributed wind is installed at commercial facility sites, including institutional and government facilities.The majority of distributed wind capacity is at industrial (37 percent), institutional (24 percent), and commercial (20 percent) facilities.[83] Total capacity grew steadily from 2003 to 2012, but growth decreased significantly beginning in 2013, primarily due to the changes in Federal and states incentives.[84] Despite the rapid growth of distributed PV, these resources contribute a small portion of generation to the overall U.S. electricity supply. As shown in Figure 2-6, they play a larger role in some states. The penetration of distributed solar PV in 2015 was about 0.34 percent of total U.S. generation.[85]

Some states and utilities are adjusting their net metering policies as the distributed PV market grows. States with longer-term policies (e.g., targets, incentives) have seen more DG adoption. Future growth will continue to be highly dependent on local and state policies, as well as retail electricity price and resource availability.

Small-Scale Distributed Storage

Small-scale distributed electricity storage (DES) is becoming more widely available and can reduce peak load, improve electrical stability, reduce power quality disturbances, and facilitate increased penetration of variable wind and solar resources. Under some circumstances, DES can reduce residential electricity bills (Figure 2-7). There are numerous distributed technologies available, including stationary battery storage, thermal energy storage (creating ice or chilled water), and plug-in electric vehicles (PEVs) with onboard batteries. Though the technology options for DES are increasing, there is currently only about 350 MW of distributed storage capacity available in the United States, which represents less than 2 percent of total electricity storage capacity and less than 0.1 percent of total electricity generating capacity.[p, 86, 87] Declining costs for storage technology, driven by greater production of batteries for EVs and state-level storage mandates,[q] will drive greater adoption of DES. Between 2007 and 2014, the cost of lithium-ion battery packs declined by almost 60 percent,[r] helping to contribute to forecasts showing rapid growth in DES over the next decade.[88]

DES, including adoption of PEVs with battery storage, could be a transformative technology.[89] Key policy considerations include identifying types of policies and regulations that could facilitate pairing DES with DG or DR to provide value to both utilities and customers. In addition, policies, regulations, and protocols could help integrate mobile DES (i.e., PEVs) into the distribution system to facilitate electrification of the transportation sector. Considering policies and programs that target barriers to deployment of cost-effective energy storage is an additional important step.

Residential Electricity Bill Savings from Distributed Electric Storage[90]

This project analyzed over 45,000 utility rates for more than 4,500 utilities covering all regions of the country.[s] To identify the electricity bill savings opportunities from the use of distributed energy storage (DES), two operational strategies are modeled:

- Flattened: Load profile flattened to minimize demand changes
- Arbitrage: Reduced energy use during peak and increased energy use during off-peak periods to take advantage of time-of-use rate designs

This analysis found that customer investment in DES can provide electricity bill savings for over 80 million residential customers. However, electricity bill savings opportunities are geographically heterogeneous and highly dependent on local rate structures, and the savings in all cases are significantly lower than the normalized cost of the DES. Furthermore, the electricity bill savings that customers realize are not commensurate with the net system benefits that DES provides as estimated by current technical literature. The shortfall between net system benefits, or the social value of DES, and customer electricity bill savings, or the private value of DES, suggests that traditional utility rate design does not adequately reflect the net benefits that a customer with DES provides to the system, and additional remuneration methods may be needed to bridge that shortfall.

[s] "Utility Rate Database," Open Energy Information, accessed January 19, 2017, http://en.openei.org/wiki/Utility_Rate_Database.

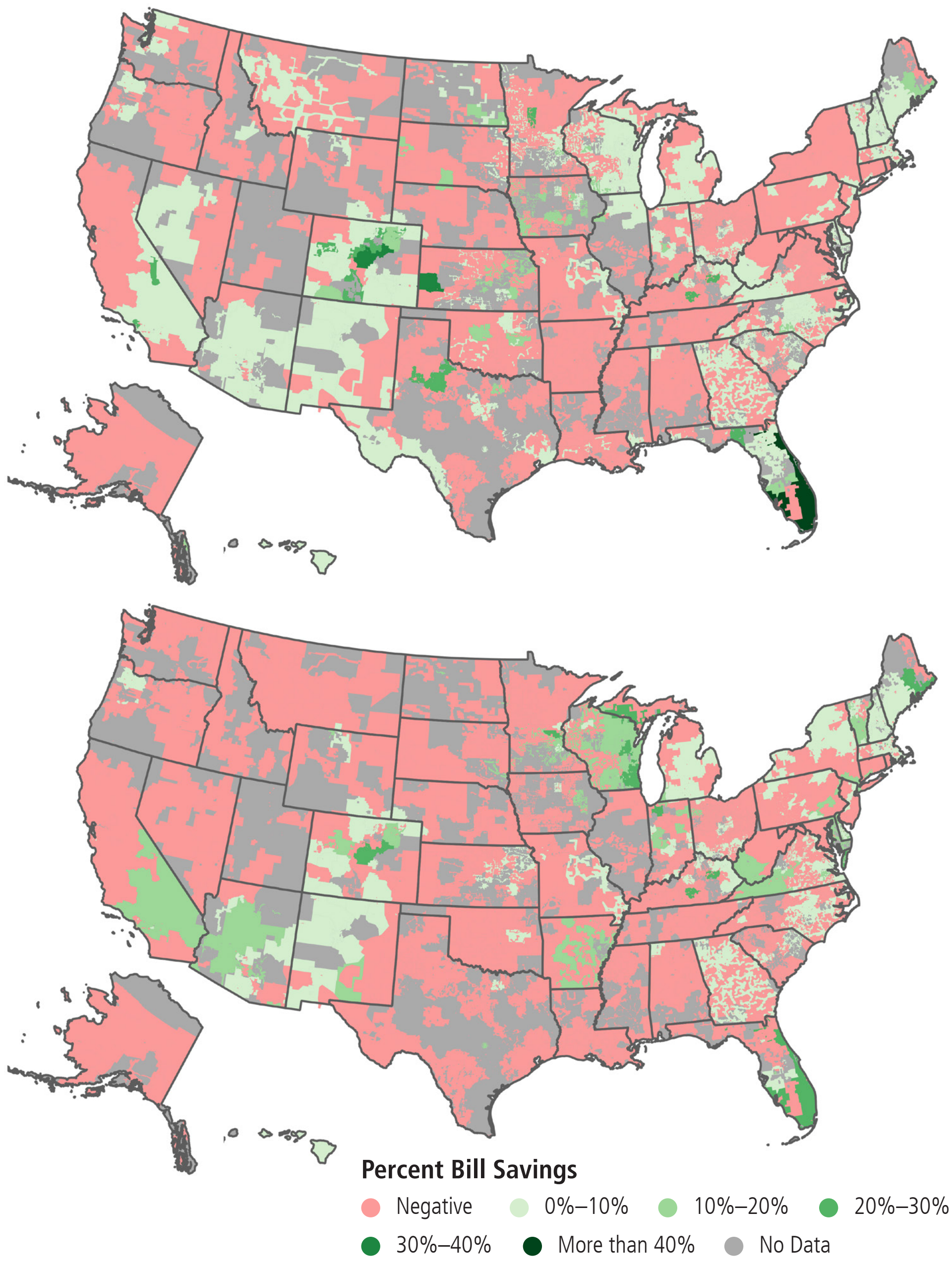
[p] The vast majority—about 98 percent—of total grid-connected energy storage capacity in the United States is pumped hydropower, which is traditionally considered grid-based storage and is not included in this report. https://www.energy.gov/sites/prod/files/2015/04/f22/Hydropower-Market-Report-Highlights.pdf

[q] In 2013, California passed Assembly Bill 2514, which mandates the state to install 1.3 GW of energy storage to their electricity grids by 2020.

[r] Between 2007 and 2014, lithium-ion battery packs decreased in cost from $1,000/kWh to $410/kWh.

Residential Electricity Bill Savings from Distributed Electric Storage[90] (continued)

Figure 2-7. Gross Residential Customer Electricity Bill Savings for the Flattened and Arbitraged Demand Profiles. Top: Bill Savings from Flattened Load Profiles; Bottom: Bill Savings from Arbitraged Load Profiles



Estimated electricity bills for residential customers with DES ranged from showing no savings to a more than 40-percent reduction in electricity bills. The opportunities for customers to save on their electricity bills are geographically similar for the flattened and arbitraged demand profiles, but they appear to lack geographic correlation with urban or rural areas. Each service territory may have several utility rates applicable to that area, so only the largest electricity bill savings available are shown in the figure (where data exist).

Challenges to Electricity Affordability

Across all households, the mean expenditure on home electricity was $1,936.[91] Electricity use and its share of total household expenditures, however, vary by region and household demographic. The average household energy consumption is, for example, higher in the West and South census regions.

The affordability of electricity service remains a challenge for many low-income residential consumers. An important indicator of the need for energy assistance is *energy burden*, usually calculated as a household's annual spending on energy as a percentage of its gross annual income.[92, 93] In 2011, the median electricity burden for *all* households was 4 percent;[94] for households not in the low-income category, it was just 2.9 percent, *but for low-income households, energy burden averaged 8.3 percent*.[95] Relatively more spending on energy bills translates into less spending on other expenses, including food.[96]

Low-income Americans are more likely to use electric heat than the national average, which tends to be more expensive than gas.[97] Electric heat use among low-income households has more than doubled from 12 percent in 1980 to 33 percent in 2005.[98] By occupant demographic, lower-income households use less electricity (kWh/household) compared to higher-income households, but they pay a considerably higher fraction of their after-tax income on electricity expenditures.[t, 99] Renters pay 26.7 percent more on electricity expenditures per square foot compared to homeowners.[u, 100] In addition, renters who pay their own utilities and have incomes less than $15,000 per year pay on average 21 percent of their income on home energy (electricity and natural gas combined).[101] There are almost 7 million U.S. households in this category. This underscores the "Heat or Eat" dilemma faced by many households with high energy burdens. The United States does not have energy poverty or high energy burden standards.

The Federal Low Income Home Energy Assistance Program (LIHEAP) provides funding to pay the electricity bills of low-income families, but the program cannot serve all eligible families, and many experience service disconnections.[102, 103] In 2011, the most recent year for which there are data, only one in six LIHEAP-eligible households received LIHEAP assistance.[104] Since the program cannot serve the entire income-eligible population, states must prioritize which vulnerable households they serve, and set their own additional standards and eligibility requirements when they apportion LIHEAP assistance. A portion of LIHEAP funds can be used for weatherization to help reduce consumers' bills, but there is wide variation in state weatherization programs' structure and quality. There are no nationally aggregated data on service disconnections associated with customers' inability to pay. State-level data suggest that instances of electricity service terminations vary widely, ranging from 5 to nearly 20 percent of low-income consumers experiencing disconnections annually.[105, 106]

The Federal Government, states, cities, and utilities offer a range of essential assistance to low-income Americans. The cost of public-purpose programs like energy efficiency programs, low-income assistance programs, and R&D programs, are collected from utility customers and usually paid for with dedicated public benefit charges or are included in a utility's general cost recovery. Both of these revenue streams are based on volumetric (per kWh) rates, and customers contribute based on their total energy consumption. For example, Ohio's Percentage of Income Payment Plan, a concessionary rate for low-income electricity consumers, is paid for by counting the revenue not collected from low-income consumers as uncollectable arrears and reimbursing the utilities out of general revenue streams.

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[t] For example, electricity accounts for 4.2 percent of after-tax income for households earning between $30,000 and $40,000 annually. Households with annual after-tax income of $100,000–$120,000 spend only 1.8 percent on electricity expenditures. Source: EPSA Analysis: Lisa C. Schwartz, Max Wei, William Morrow, Jeff Deason, Steven R. Schiller, Greg Leventis, Sarah Smith, et al., *Electricity End Uses, Energy Efficiency, and Distributed Energy Resources Baseline* (Berkley, CA: Lawrence Berkeley National Laboratory, January 2017), 25, https://energy.gov/epsa/downloads/electricity-end-uses-energy-efficiency-and-distributed-energy-resources-baseline.

[u] Note that total energy expenditures include non-electricity sources such as natural gas and heating oil.

Utilities in most states administratively determine a public benefits surcharge, such as $0.002/kWh. These funding structures mean that any reduction in a consumer's per kWh payments reduces that consumer's contributions to these programs; energy efficiency measures that reduce overall consumption may similarly reduce funding for assistance programs. Revenue decoupling can prevent the underfunding of these programs but not the shift of their costs among consumers.

Access to Distributed Energy Resources and New Energy Services for All Consumers

Low-income communities stand to benefit from energy efficiency and clean energy more than other communities because these residents have higher energy burdens and often bear disproportionate impacts of pollution[107] and climate change.[108] Current modes of promoting energy efficiency and clean energy, however, are not always designed to benefit low-income communities. In addition to low-income consumers having less energy-efficient homes on average, it is much more expensive for utilities to provide energy efficiency programs to those consumers than to average-income residential or commercial consumers.[109]

Low-income households are often renters, creating a split-incentive problem for energy efficiency investments. The landlord sees no incentive to make energy efficiency investments since the benefit goes to the tenant who pays the electricity bill; the tenant, on the other hand, sees little incentive to make expensive, long-term energy efficiency investments since future benefits will accrue to future tenants. The split incentive problem leads to declining energy efficiency over time when compared to owner-occupied housing, compounded by the tendency for low-income Americans to occupy older buildings.[110] Finally, low-income consumers often lack access to capital for home energy improvements and have limited access to the most modern and efficient appliances and electricity service. DOE's Weatherization Assistance Program (WAP) funds low-income energy efficiency upgrades, but unfortunately, the needs dramatically exceed WAP funding.

The California Public Utilities Commission (CPUC) recently found that, since 1999, rooftop solar customers had a median household income of $91,000, while the median income in California was $54,000 and that of the investor-owned utility (IOU) customers was $68,000.[111] A survey conducted by the National Renewable Energy Laboratory found that solar adopters in San Diego County had an average household income of $165,000, compared to $115,000 for non-adopters.[112] In principle, lower-income consumers could benefit from installing distributed solar and other clean energy technologies in their homes in the same way that higher-income consumers do, but many barriers have prevented this, including lack of funding or financing, lack of ownership, or a rooftop being in poor repair.[113] In addition, many low-income Americans and businesses in low-income communities rent their homes and offices, making upgrades harder to arrange and pay back through energy or bill savings.

Utilities and other energy-service providers can make solar PV-market participation available to low-income customers through arrangements like community solar, which may provide cash-flow-positive solutions to address the needs of a large down payment, favorable credit rating, or owner-occupied single-family home. One common model is for community solar project developers to form PPAs with the utility for a solar development located in a community or offsite. A specified number of customers can then subscribe to the program for a monthly fee and receive a virtual net metering bill credit for a portion of energy produced. In some cases, onsite, community, and shared solar programs can use Federal low-income energy assistance through programs like LIHEAP, WAP, and Low-Income Housing Tax Credits to benefit consumers who would otherwise be deemed ineligible for energy efficiency upgrades. The Clean Energy Savings for All Americans Initiative is a cross-agency initiative with participation from DOE, EPA, Department of Housing and Urban Development, Department of Agriculture (USDA), Department of Labor, Corporation for National and Community Science, and Department of the Treasury. The initiative focuses on ensuring that low-income households have access to solar options through a variety of these mechanisms.

Electricity Issues in Small, Rural, and Islanded Communities

Rural and islanded electricity systems are microcosms of the larger electricity grid, but they also face unique challenges being isolated from the grid or being located in low-population areas. Rural electricity systems have a smaller customer base but more miles of distribution line to maintain than utilities serving urban areas. Rural electric cooperatives (co-ops) cover three quarters of the country's land mass, with a total membership of approximately 42 million people.[114] Per mile of distribution line, co-ops serve an average of 7.4 consumers and collect annual revenue of about $15,000, while IOUs serve an average of 34 customers and collect $75,500. This disparity in customers and revenue per line-mile poses a challenge for investments in rural electricity infrastructure.[115]

Islanded systems can be actual islands or "islanded" by being isolated from the larger electricity grid (e.g., electricity systems serving small villages in rural Alaska). Islanded systems also have small customer bases, with high capital costs and high shipping costs for infrastructure and fuel supplies. They may also require a high level of redundancy due to extreme weather conditions and general isolation.[116]

Grid operators face the challenge of delivering reliable, affordable electricity in remote areas. Assistance with financing electricity infrastructure and improved telecommunications, such as broadband, could help provide more affordable, reliable electricity in rural and islanded communities. Improved access to broadband in rural communities would help the deployment of DR, storage, DG, and other technologies.

In addition, education and training may be required to enable residents of small, remote communities to operate and maintain their electricity systems when new technologies are deployed. Co-ops and utilities providing electricity in rural and islanded communities can provide technical assistance with integrating renewable electricity, storage, or other improvements in electricity delivery.

The Federal Government plays a role in encouraging renewable energy and economic development in rural areas. DOE and other Federal agencies have several energy efficiency and renewable programs available to residents in rural areas, even if these programs are not specifically designed for rural communities; these include the National Community Solar Partnership, WAP, the Better Buildings Challenge, and others.[117, 118, 119] USDA's Rural Utilities Service (RUS) provides financing for electric utilities (wholesale and retail providers of electricity) that serve customers in rural areas.[120] RUS loans include financing for generation and transmission technologies and distribution modernization. In recent years, however, the RUS loan program has been undersubscribed.

Powering Isolated Communities in Alaska

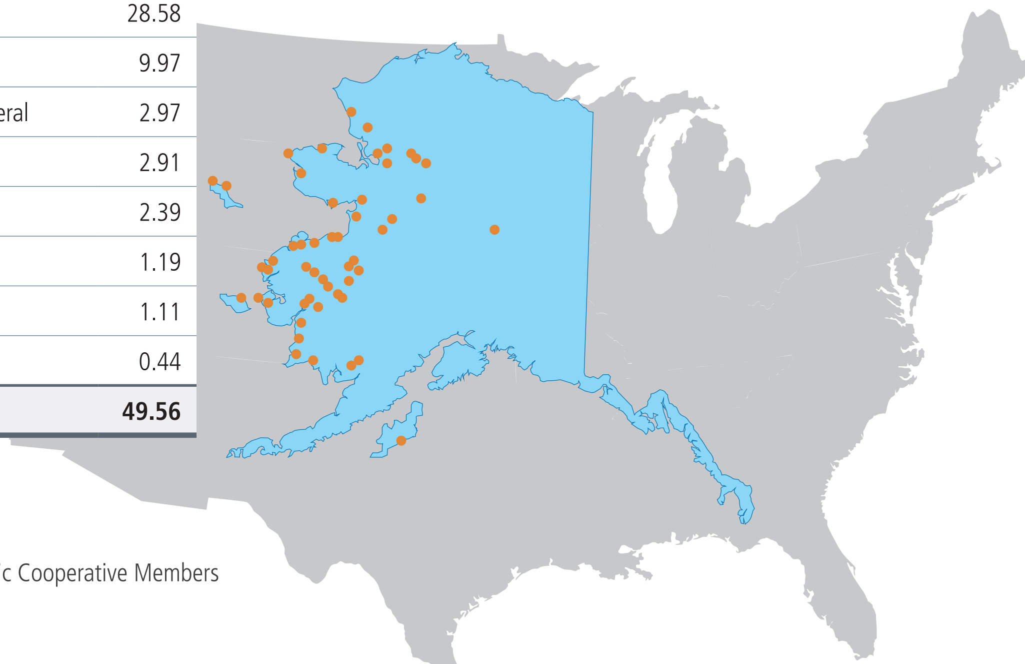
Rural Alaskan communities have high seasonal load peaks, with high demand in the winter for heating and lighting. Many smaller Alaskan communities rely on diesel fuel for electricity generation and pay $0.50 to $0.80 per kWh because of the high cost of fuel and shipping, higher capital costs due to the small scale of generation, and the greater need for redundancy in generation (Figure 2-8).[121]

Battery storage has improved reliability in Alaska communities connected to the larger grid in the central part of the state,[122] where batteries have been installed primarily for frequency and voltage regulation, not to store intermittent renewable energy.[123] As a result, Alaskans have experienced fewer outages, and grid operators use less spinning reserve capacity with the addition of large-scale battery storage.[124]

Figure 2-8. Electricity Costs in Rural Alaska

Average Alaska Village Electric Cooperative Village Electricity Cost (¢/kWh)

Fuel	28.58
Power Production	9.97
Administration and General	2.97
Depreciation	2.91
Consumer Accounts	2.39
Distribution	1.19
Interest	1.11
Taxes	0.44
Total	**49.56**



The Alaska Village Electric Cooperative serves more than 50 small communities dispersed across large distances and in remote regions with harsh climatic conditions. These factors contribute to average electricity prices being approximately five times the U.S. national average.

Alaskan co-ops are installing more wind energy and improving power-control technology in rural areas to better manage electricity systems that primarily run on diesel fuel.[126] The Alaska Center for Energy and Power has studied ways to reduce reliance on diesel generation, while recognizing the difficulty in eliminating diesel generators because they provide important services beyond electricity generation,[127] including waste heat and inertia for local electricity systems.[128] Systems that use both diesel and wind energy have reduced fuel costs and emissions but are more complex and require more training for operators.[129] Also, improved broadband access to the large data streams necessary for managing these complex systems would make it easier to run them in remote areas and on islands.[130]

Innovative Rural Electric Co-Op Programs

While energy efficiency is more cost-effective than building new infrastructure, rural energy efficiency programs face a unique challenge. Rural communities have a greater proportion of low-to-moderate-income families who may have problems financing energy efficiency investments. Also, seasonal demand peaks related to agriculture can make the payback time longer for energy efficiency investments, and co-ops serving rural communities may have less access to capital and technical expertise than IOUs.[131] In spite of the challenges of operating in rural areas, co-op sales grew 3.3 percent in 2014 compared to 1.1 percent growth across the entire retail electricity sales industry.[132]

Co-ops have installed the greatest percentage of advanced metering infrastructure (AMI), with 51 percent penetration, compared to 41 percent for IOUs and 26 percent of publicly owned utilities.[133] Rural electric co-ops have the advantage of being smaller and more nimble than large IOUs regulated by public utility commissions (PUCs). In addition, they can more easily adopt energy efficiency or renewable energy programs tailored to their members. Some rural co-ops are adding biodigesters to convert solid waste from dairy cows to electricity, smart electric water heaters to store wind energy, improved forecasting for solar and wind energy, and other DR technologies that take advantage of resources in rural areas. Many of these DR and storage technologies could be expanded with improved telecommunications access.[134]

The RUS partners with cooperatives to finance improvements in rural communities, many of which are low-income.[135] Roanoke Electric Cooperative implemented a program to make investments tied to each meter that are funded by an RUS loan.[136] The co-op paid for installation of improved insulation, duct and air sealing, heat and water pump upgrades, and efficient lighting. The co-op recovers its efficiency investment through a tariff on the bill from co-op members, who still see savings on their bill from the reduced electricity use.[138] After efficiency upgrades, the average savings was $120, which the member and the co-op would split; an average member would save $60 per month on his or her bill, and the co-op would pay off the efficiency upgrade in 10 years.[139] Improvements to RUS loan programs, many of which are undersubscribed because of the programs' complexity or the inability to refinance to lower interest rates, could accelerate the development of renewable energy and energy efficiency projects in rural areas.

Electricity as a Driver of Economic Growth in Tribal Communities

Electrification in the United States is among the highest in the world, but there is not universal access to electricity on Indian reservations. The interdependencies of electricity access, economic well-being, and quality of life underscore the importance of electrifying tribal lands.

According to the 2010 census, 1.1 million American Indian or Alaska Native people lived on reservations and Alaska Native Village Areas. While current data are limited, an EIA study in 2000 found that 14.2 percent of Native American households on reservations did not have access to electricity; the Navajo Reservation represents about 75 percent of this total.[v, 140] Across all tribes, one in seven Indian households living on reservations was without electricity service.[141] A combination of EIA's electrification rates and 2010 census data would suggest that there could be as many as 160,000 Native Americans without electricity. Data from the 2007–2011 U.S. Census American Community Survey also concludes that, on tribal lands, thousands of Native Americans are still living without basic electricity services.

There are significant challenges to addressing electricity access on Indian lands. These challenges include remote locations, widely dispersed homes, and the prohibitive cost of utility distribution lines. Despite reductions in wind and solar costs, many tribes have not been able to take advantage of their wind or solar resources.[142] Tribes have limited access to private capital for projects in Indian Country.

DOE's Office of Indian Energy Policy and Programs recently modernized its technical assistance strategy to better assist tribes in improving energy access and services by recognizing that the questions of today's grid are more complex and sometimes require longer-term partnerships. The Bureau of Indian Affairs at the Department of the Interior has several programs that provide technical assistance to American Indian tribes for energy development. USDA's RUS offers low-cost loans to rural utilities, including tribal initiatives for increasing grid access, and state programs also exist. For example, in New Mexico, the Tribal Infrastructure Fund, created by the Tribal Infrastructure Act in 2005, recognizes that many of New Mexico's tribal communities lack basic infrastructure including, but not limited to, water and wastewater systems, roads, and electrical power lines. Through this competitive funding, all Federally recognized tribes, nations, and pueblos

[v] The 2000 EIA study is the most current study on the availability of electricity on reservations. A study from DOE's Office of Indian Energy Policy and Programs is forthcoming.

within New Mexico have an opportunity to submit a robust project proposal for their communities. At each funding cycle, the project proposal is evaluated and, based on scoring, is awarded funds through the 13-person Tribal Infrastructure Board, which is administratively attached to the New Mexico Indian Affairs Department.

Tribes also face regulatory challenges and limitations. The tax-exempt, non-profit status of Federally recognized tribes precludes them from taking advantage of the Federal Production Tax Credit or Investment Tax Credit without costly and complicated corporate structures.[143] These tax credits have supported a dramatic expansion of renewable energy production on non-tribal lands. Lengthy regulatory processes also make it more difficult to develop energy resources and electricity transmission projects.[144] Siting and permitting rules for transmission rights-of-way on tribal lands were simplified and clarified in 2015. These changes may offer opportunities for tribes to build out grid access to unconnected rural areas and increase connections to renewable energy projects.

Indian Lands have over 9 million MW of renewable energy potential,[145] but only 125–130 MW has been installed on tribal lands, due to the lack of capital.[146] Making renewable energy tax credits refundable and providing loan guarantees would help tribes develop their renewable energy resources. Some tribes have also expressed interest in improving their capacity to run energy programs by developing tribal energy offices, comparable to state energy offices that run energy efficiency and energy security programs.[147]

The Federal Government has a trust responsibility to protect tribal treaty rights, land, and resources, and it has a longstanding policy of encouraging economic development in Indian Country. In addition to supporting improved access to electricity and incentives for renewable energy development, the Federal Government should improve consultation with tribal governments on infrastructure projects. Frequently, tribal consultation takes place near the end of the siting and permitting process, too late to allow for meaningful input from tribes. Federal agencies have different procedures and definitions for consultation, and some tribes lack the staff or technical expertise to review permitting documents. The Federal Government should implement procedures that ensure early and meaningful consultation with tribal governments, and Federal staff should receive training about how to provide meaningful consultation to tribes to identify and addresses concerns.

The availability of programs, new tools, and technical assistance does not change the reality that providing access to electricity is very expensive for tribal utilities. Indeed, the electrification of rural America in the 1930s was achieved through economic transfers from urban customers to rural customers, e.g., through high levels of interest-free loans and grants from the Federal Government. Prioritizing universal electricity access for tens of thousands of Americans without electricity may again require significant Federal intervention.

Maximizing the Value of Energy Efficiency

Energy efficiency, often referred to as the "first fuel," provides benefits for the electricity system, including avoided costs for energy, as well as generation, transmission, and distribution capacity; less volatile electricity market prices; reduced service disconnections due to arrearages on bill payments; and improved system reliability (Figure 2-9). While energy efficiency reduces electricity, natural gas, and other home-heating fuel consumption, it equally supports a host of non-energy benefits for individual participants and society as a whole;[148, 149] benefits for individuals include reduced energy bills and more disposable income, increased property values, improved comfort, lower maintenance costs, higher productivity, and positive health impacts.[w] For society as a whole, non-energy benefits include improved energy security and independence; reduced air emissions, greater water savings, and other environmental benefits; reduced costs to operate public facilities; job creation and local economic development; and broad health benefits, such as reduced asthma cases from cleaner air.

[w] For information on how to quantify the multiple benefits of energy efficiency, see EPA's *Assessing the Multiple Benefits of Clean Energy: A Resource for States* (2011), https://www.epa.gov/statelocalclimate/assessing-multiple-benefits-clean-energy-resource-states.

Figure 2-9. Multiple Benefits of Energy Efficiency Improvements[150]

Energy efficiency improvements include energy and non-energy benefits for individual participants, the electricity system, and society as a whole.

Regulatory approaches such as decoupling, incentives, or lost revenue adjustments can be used to promote utility investments in energy efficiency. Building owners can also use a variety of financing mechanisms to implement energy efficiency improvements, including energy savings performance contracts, property-assessed clean energy loans, or energy-focused loans from national lenders.

Energy efficiency policies—such as building energy codes, appliance and equipment standards and labeling, and targeted incentives—have played a significant role in slowing the growth of electricity consumption. Incremental annual energy savings from utility customer-funded electric efficiency programs in the utility sector are expected to reach about 0.8 percent per year in the United States by 2025, driven primarily by compliance with statewide savings or spending targets typically focused on energy efficiency programs.[151]

Efficiency programs funded by electric utility customers, as well as energy efficiency standards for appliances and equipment and more efficient building energy codes, are likely to continue to offset the majority of electric load growth. Advances in technology and the continued growth of the broader energy efficiency and energy-management industry have also played important roles in achieving significant levels of energy savings.

A broad range of policies and programs can help the American economy capture value from energy-efficient technologies and practices. At the Federal level, DOE supports cost-shared R&D of new energy-efficient technologies and practices applicable to all end-use sectors including lighting; refrigeration, air conditioning, and heat pump technologies; new building design and construction tools and materials; sensor and controls; industrial processes and materials; EVs; DG and DES technologies; and others. Technology development efforts are usually accompanied or followed by technology demonstrations and the development of test methods to facilitate market acceptance. Labeling and technical assistance (for example, through EPA's and DOE's ENERGY STAR and DOE's Better Buildings programs), provide the information necessary for consumers to identify opportunities for reducing the costs of electricity through investments in new, more energy-efficient products, or improvements to the performance of existing buildings and processes. Green building-certification programs promote energy-efficient buildings. Incentives, financing, and targeted procurement programs implemented by governments and utilities help enable or motivate investments in higher-efficiency products and accelerate the market penetration of new, more energy-efficient and clean energy technologies. Finally, energy efficiency building codes and standards for equipment and appliances ensure consistent market adoption of cost-effective efficiency technologies. The primary objective of these efforts is to enable consumers to obtain the same or improved end-use services at a lower total cost, while also yielding environmental and economic benefits. Today, such programs are effectively stimulating efficiency gains in all new buildings and vehicles, and most appliances and equipment.

Substantial electric efficiency gains are possible in all end-use sectors. The National Academies found that full deployment of cost-effective energy-efficient technologies in buildings could eliminate the need to build new electric generating capacity in the United States through 2030.[152] If buildings were to adopt today's best available technologies, energy-use intensity (thousand British thermal units per square foot) could decrease by at least 50 percent for single-family homes and by 42 percent for commercial buildings.[153] New electricity savings and DR opportunities are being unlocked by the digitization of end-use devices and the build-out of layers of communications infrastructure to allow them to both communicate their state and be controlled—further enabling grid-system-wide efficiencies and functionalities. Developing effective technologies and strategies for realizing these value-creation opportunities will require improved data on the actual performance of more energy-efficient appliances, equipment, and buildings; variation among different categories of consumers; and the constellation of product and service providers that serve and influence the decisions of consumers.

Miscellaneous Electric Loads Are a Growing Share of Electricity Demand

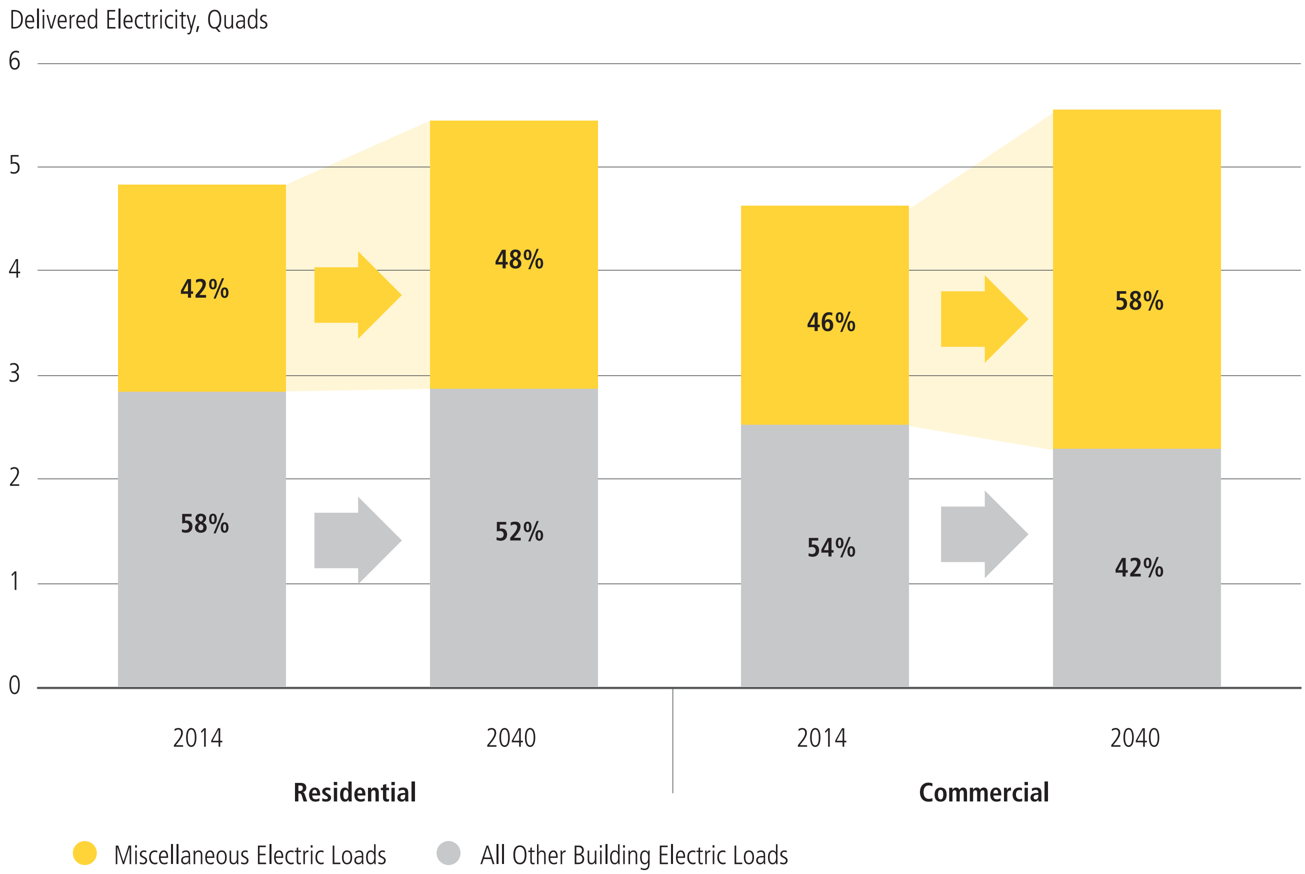
The shares of end-use electricity demand in residential and commercial buildings in 2014 are seen in Figure 2-10. Most building-sector end uses are expected to represent declining shares of future electricity demand, with only MELs,[x] residential air-conditioning, and commercial office equipment expected to increase their shares.[y] The energy consumption of MELs is projected to increase significantly from 2014 to 2040, from 42 to 48 percent in the residential sector and from 46 to 58 percent in the commercial sector.[154] The increased share of energy used by MELs follows the continued emergence of new electricity services and the less effective

[x] For a more detailed discussion of MELs, see: http://energy.gov/eere/buildings/downloads/bto-investigates-miscellaneous-electric-loads.

[y] MELs represent a broad range of electric loads that do not fall within a building's core end uses of heating, ventilation, air conditioning, lighting, water heating, and refrigeration. MELs include a portion of 'unknown' electricity loads meant to align discrepancies between supply- and consumption-side data sources.

coverage of major loads by existing policies designed to accelerate efficiency gains. Additional action is needed to improve data collection and to further expand technology development, product testing, labeling, and minimum standards programs to better cover MELs.

Figure 2-10. Share of Miscellaneous Electric Loads Compared to All Other Building Electric Loads, Residential and Commercial Sectors, 2014 and 2040[155]



Compared to other loads, MELs are projected to increase significantly in their share of total delivered electricity in residential and commercial buildings. Projections are based upon the business-as-usual assumptions in the EPSA Base Case.[z]

Energy Efficiency Codes and Standards Help Reduce Consumption and Save Money

Energy efficiency policies—such as building energy codes; equipment efficiency standards; mandatory, as well as voluntary, labeling like ENERGY STAR; and targeted incentives—have played a significant role in slowing the growth of electricity consumption. Because buildings often have lifetimes of 75–100 years, policies and market forces that improve efficiency in base building systems can have lasting benefits. Advances in technology and the continued growth of the broader energy-management industry have also played roles in creating significant value through energy savings.

[z] For additional detail on the EPSA Base Case, see Table 3-3 "Summary of DOE QER Analysis Cases using EPSA-NEMS."

Building energy codes, energy conservation standards, and the voluntary ENERGY STAR program for appliances and equipment set a minimum level of energy efficiency performance as well as leadership efficiency levels. Codes and standards address market barriers related to information and transparency, materiality, and split incentives.[aa] These policies have the goal of cost-effectively reducing energy consumption to provide value to customers and meet long-term energy goals.

States and developers of model codes point to two opportunities to increase the impact. The first is the long-standing interaction between energy codes and ratepayer-funded efficiency programs. While these codes and programs often share similar policy goals, increasingly stringent energy codes may create a challenge where, by increasing the baseline efficiency of all buildings, they limit the energy savings that can be captured by efficiency programs. Maximizing value to consumers and other parties requires state policymakers to align goals for all parties. Such alignment will help ensure that modern energy codes and voluntary programs complement each other to achieve cost-effective energy efficiency for all.

The second opportunity lies in the increasing connectivity and controllability of consumer devices. Expanding connectivity may increase the energy used by consumer devices, while also offering opportunities to provide value through improved energy management and greater flexibility of electricity demand. Encouraging the use of connected digital devices in ways that save energy and provide flexibility to the grid has not historically been a consideration in building energy codes. But, codes that encourage effective use of building and device connectivity and controls could directly provide value to building occupants, as well as increase the value of the building as a grid asset.

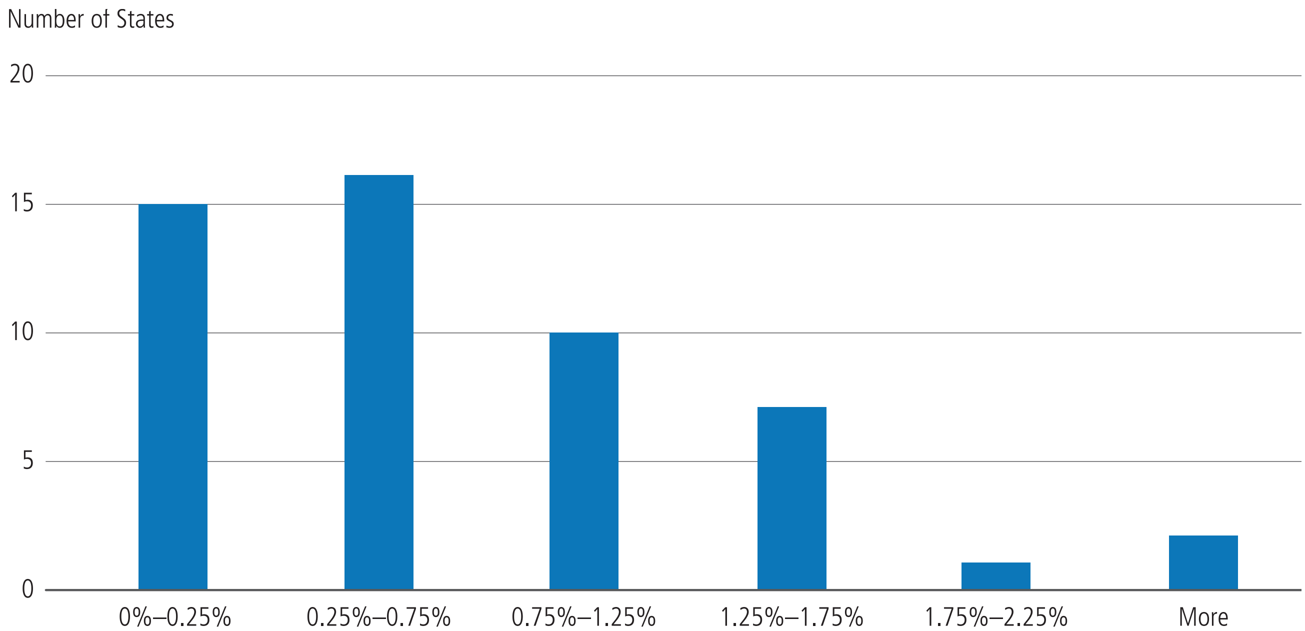
State and Local Energy Policies and Programs Deliver Efficiency

Nearly a third of states are saving at least 1 percent of electricity consumption each year through programs funded by utility customers. Roughly another third of states—most relatively new to energy efficiency—are saving between 0.25 percent and 0.75 percent (Figure 2-11).[156] Many states are increasing their efficiency targets as they meet initial goals and are on track to achieve even higher savings. Energy efficiency programs funded by utility customers spent $6 billion in 2013.[157] It is estimated that the average total cost of saving electricity among U.S. utility efficiency programs across all market sectors for the period 2009 to 2013 is 4.6 cents per kWh saved, split roughly in half between the utility (or other program administrator) and program participants.[158, 159] This is much lower than the average price of electricity in the United States in 2014, which was 10.44 cents per kWh.[160] Another way to view the cost-effectiveness of efficiency is to compare the cost of energy efficiency and the cost of a new power plant. The average levelized cost of saved energy from energy efficiency programs in the United States is estimated at $46/MWh, versus the levelized cost of energy for natural gas combined-cycle generation, with its sensitivity to fuel prices, at $52 to $78/MWh.[ab, 161]

[aa] Chapter III (*Building a Clean Electricity Future*) discusses the potential for building energy codes and appliance standards.

[ab] This comparison has some limitations. For example, the cost of saved energy usually is calculated at the meter of the end-use customer, while the levelized cost of energy supply is calculated at the busbar of the power plant, which typically does not reflect energy lost in transmission and distribution (i.e., line losses) between the generator and end-use customer.

Figure 2-11. Percent Electricity Savings from Energy Efficiency Programs Funded by Utility Customers, 2014[ac, 162]

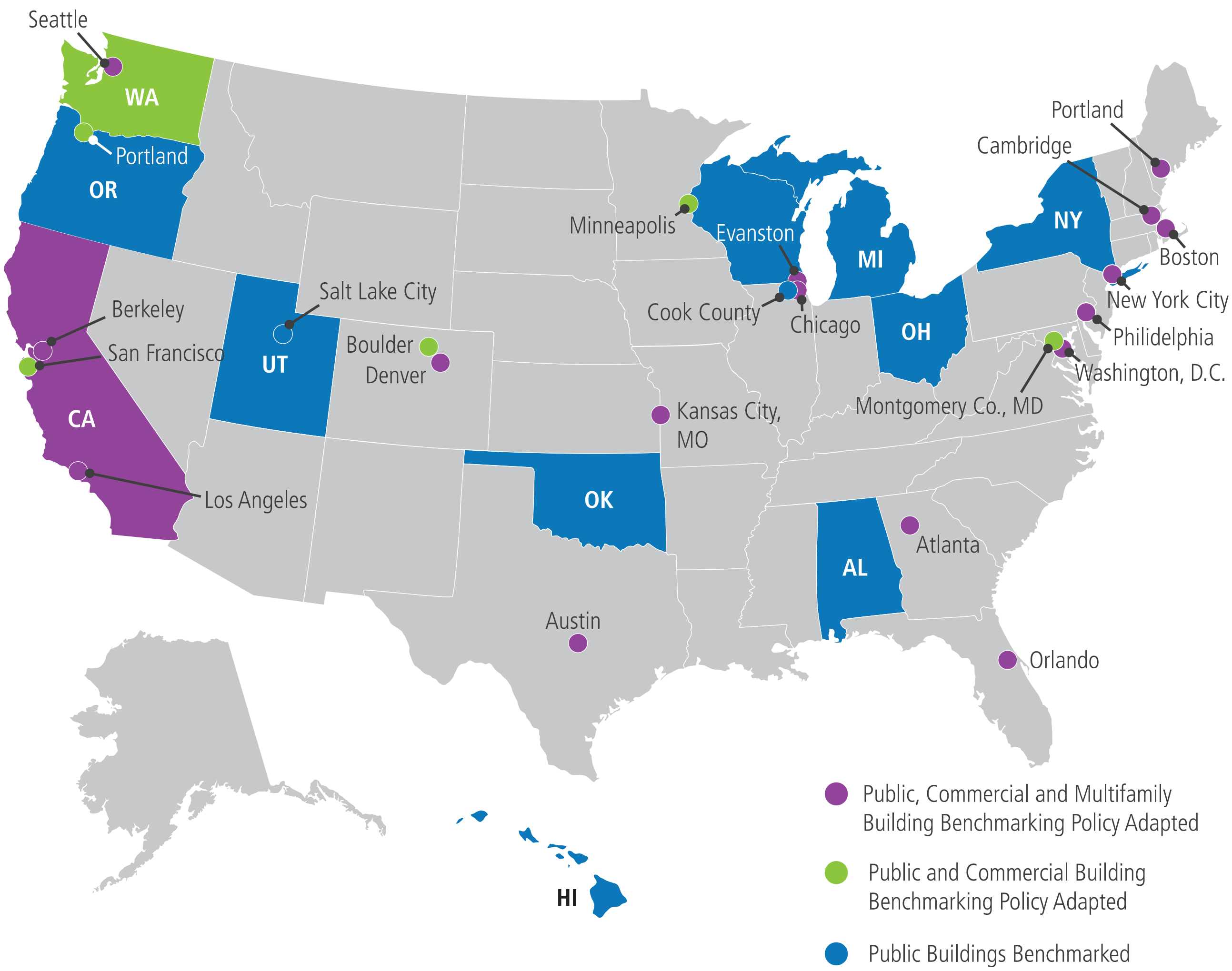


Nearly a third of states are achieving savings of at least 1 percent per year and another third of states are saving between 0.25 percent and 0.75 percent of retail sales. On average, national savings reported in 2014 from utility and public benefits electricity programs were equal to 0.7 percent of sales.

Recent research indicates that inefficient buildings may yield a reduced mortgage value due to energy price risk.[163] Improving energy efficiency can help protect against this potential loss of financial value. Many states and cities that require reporting of buildings' energy performance have implemented energy benchmarking and transparency policies for buildings. This reporting increases building owners' knowledge of properties' energy usage; provides greater transparency for current and prospective tenants; highlights cost-effective, energy-saving opportunities; and provides market data to enhance deployment of efficiency efforts on behalf of relevant agencies.[2] Building benchmarking and auditing data provide a database of information that supports better valuation of energy efficiency measures in commercial buildings for future owners and investors. Regulations that require building energy benchmarking, periodic energy audits, corrective actions (e.g., retrocommissioning), or point-of-sale disclosure or upgrades (or both) for commercial buildings have been adopted by 8 states and 14 cities (Figure 2-12).

[ac] This figure was adapted from *The 2015 State Energy Efficiency Scorecard* (American Council for an Energy-Efficient Economy, 2015) http://aceee.org/research-report/u1509.

Figure 2-12. U.S. Building Benchmarking and Disclosure Policies[165]



A growing number of states and communities are adopting building information transparency policies. These include building energy benchmarking, periodic energy audits, corrective actions (e.g., retrocommissioning), and point-of-sale disclosure or upgrades (or both).

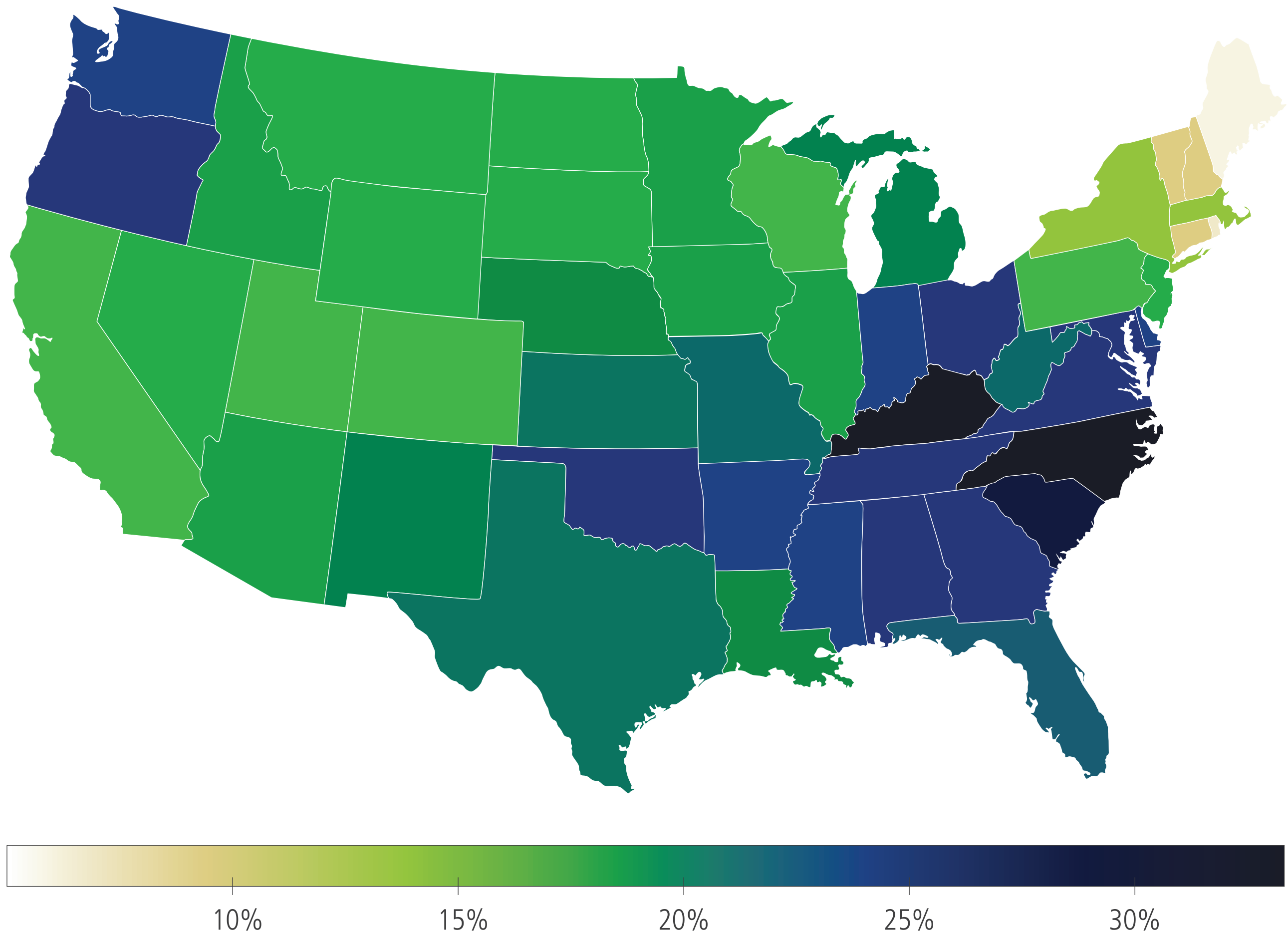
Many states and localities have policies in place to lower barriers to financing energy efficiency projects. Examples of financing initiatives include on-bill financing, state revolving loan funds for clean energy projects (including energy efficiency), other state energy office programs,[166] utility financing programs, and local property-assessed clean energy programs[167] for residential and commercial buildings. While a majority of states have at least one type of energy efficiency financing program, the availability of multiple programs and the percentages of the states' population with access to these programs vary significantly.[168] At least 23 states have an on-bill financing program, which is intended to decrease the financial hurdle for making energy efficiency investments by allowing customers to pay for the upgrades through their monthly utility bill.[169]

While efficiency opportunities are large in all states, the most cost-effective measures vary regionally based on factors such as climate, energy prices, and building practices. One example comes from the residential sector, where DOE analysis identified a suite of cost-effective energy efficiency upgrades to the current stock of U.S. single-family detached homes with total potential savings of 245 terawatt-hours per year (~6 percent of the total annual national electricity consumption in 2014). Initiatives to upgrade HVAC systems, particularly replacing electric furnaces with variable speed heat pumps, could produce substantial electricity savings in the South Census regions (West South Central, East South Central, and South Atlantic), where both average household electricity consumption and population growth rate are higher than other regions.[170] Additional analyses can help states, utilities, and consumers understand which measures offer the greatest net benefits in their region.

State and local governments, as well as the utilities that they regulate or own, lead the effective implementation of many energy efficiency policies and programs. Many state and local governments manage the development and implementation of ratepayer-funded utility programs that incentivize and provide technical support to capture value through increasing energy efficiency investments by consumers. Ratepayer-funded programs directed at improving end-use efficiency and management are now funded at $6–7 billion per year.[171] Twenty-six states have enacted an Energy Efficiency Resource Standard (EERS), which requires utilities to reduce their customers' energy consumption by a certain percentage of annual sales. According to the American Council for an Energy Efficient Economy, "in 2014, states with an EERS achieved incremental electricity savings of 1.2 percent of retail sales on average, compared to average savings of 0.3 percent in states without an EERS."[172] EERS policies, or similar requirements, are projected to be a key driver of future energy efficiency programs, accounting for nearly three quarters of all investment.[173] Additionally, by 2020, these state EERS are estimated to reduce electricity consumption in those states by 8 percent to 10 percent below projected business-as-usual.[174] Analysis of over 2,100 program-years of data indicates that these programs cost an average of 4.6 cents per kWh saved, making energy efficiency a cost-effective approach for lowering consumer energy bills.[175]

There is significant, remaining potential for creating value to consumers and others through cost-effective electricity savings. As an example, Figure 2-13 shows cost-effective electricity savings in single-family residential housing across every state. This analysis suggests that most states can cost-effectively save 15–30 percent of electricity used in single-family dwellings through efficiency programs.

Figure 2-13. Potential Electricity Savings from Residential Energy Efficiency Upgrades, by State[176]



Modeling indicates that homeowners in most states can reduce their electricity consumption by 15 to 30 percent after implementing net present value positive energy efficiency measures, compared to current consumption.

Zero Energy Buildings

In concept, zero-energy homes (and zero-energy buildings [ZEBs] in general[ad]) are "energy-efficient buildings where, on a source energy basis, the actual annual delivered energy is less than or equal to the onsite renewable exported energy." Other definitions use site-energy-based criteria—a less-stringent definition than source-based, which includes the site energy plus the energy used to provide and distribute it. And, others use time-dependent, valuation-based definitions, which seek to assign a valuation of energy produced or consumed to better reflect the actual costs of energy, as adopted by the California Public Utilities Commission. The difficulty in meeting ZEB criteria varies between definitions. Furthermore, the cost-effectiveness of ZEBs depends highly on the age and type of building, location (climate), incentives (e.g., utility rebates), electricity rate and structure, and the cost of renewable energy generation.

[ad] The term "zero-energy–building" (ZEB) used here is considered to have the same meaning as similar terms such as zero-net energy building (ZNEB) or net-zero energy building (NZEB).

Zero Energy Buildings (continued)

Recent studies demonstrate that many new ZEBs in the commercial sector can be cost-effective, with overall costs falling within the same range as conventional, new construction projects. The explicit goal of net-zero energy throughout the design process is critical to minimizing construction costs. In California, for example, it is feasible for many commercial buildings to be ZEB using a time-dependent, valuation-based definition. However, several building categories, such as sit-down restaurants, hospitals, and large offices cannot reach ZEB designation using rooftop solar—though they might reach that designation using parking lot photovoltaic (PV) systems. Having enough available roof space for onsite PV is often a challenge. Contracting with offsite renewable energy systems or participating in virtual net-metered or community-scale solar projects provide greater flexibility for buildings to be ZEB or ZEB-ready. This is an active area of policy discussion.

Other challenges to the adoption of ZEBs are the lack of integrated design practices, cost barriers, lack of skilled and knowledgeable workforce in design and construction, additional design and construction cost, improper building management, user behavior, and integration of solar PV, either as part of the building construction process or as a parallel step during that process.

Policies that encourage zero-energy homes increase demand for not only energy efficiency but also other distributed energy resources, such as distributed generation and battery storage. High levels of market penetration could have significant impacts on the grid, reducing overall grid electricity consumption. More distributed energy resources driven by zero-energy targets can potentially lead to higher levels of demand response. California has announced a target of making all new residential buildings net-zero energy by 2020. It is likely that a significant fraction of existing residential buildings would struggle to attain zero energy onsite due to roof angles, poor insulation, insufficient roof area (particularly in the case of high-rise buildings), and other factors. This may place a premium on finding a way to procure offsite sources to offset whatever amount of site energy remains.

Using government-owned buildings, especially schools, to demonstrate the multiple benefits that ZEBs can help realize (such as improved student health and reduced operating costs) could lead to more widespread adoption of such building construction, renovation, and management practices. For example, one study showed that improved heat-pump air conditioning in relocatable classrooms could simultaneously reduce the energy needed for heating, ventilation, and air conditioning by 50–70 percent and significantly improve indoor air quality. More studies are needed on the cost-effectiveness of new ZEBs, considering an integrated package of energy efficiency measures rather than analysis of discrete measures, as well as a better understanding of the cost-effectiveness of ultra-low energy or ZEB retrofits. Some of the key adoption issues that need to be resolved for "shared solar" or offsite renewable generation include a lack of uniformity and standardization of consumer contracts, rate design, and program structure, and the need for a framework to track and match offsite renewable resources to specific buildings claiming an offset. Thus, an analysis of the policy choices, impacts, and cost implications of ZEBs would be helpful.

Maximizing the Value of Dynamic Consumer Assets

Advances in communications, metering, sensors, controls, and storage technologies are enabling consumers, utilities, and other service providers to more actively or passively manage electricity loads in response to price and other system constraints. This is in contrast to energy efficiency measures that result in static reductions in energy consumption by an appliance, equipment, or building. The value derived from dynamically managing consumer assets can be economic, as well as environmental, and can accrue to the consumer, utility, and others. DR, which allows utilities, grid operators, or other intermediaries to call for specific changes in demand when needed, offers benefits in flattening load curves and supplying essential reliability services, such as frequency regulation. Smart meter infrastructure, sensors, and communication-enabled devices and controls give electricity consumers and utilities new abilities to monitor electricity consumption and potentially lower usage in response to time, local distribution, or price constraints. Smart meters also provide a number of other consumer benefits, including enhanced outage management and restoration, improved distribution system monitoring, and utility operational savings.[177] Other benefits include improvements in building user satisfaction and greater worker productivity. Taking full advantage of the value of consumer assets depends on minimizing the risks associated with them—in particular, cyber threats and privacy concerns.

Modern Communications Networks Provide the Backbone for Maximizing Value of Electricity Assets

New technologies supported by private-sector vendors and government R&D are making their way onto bulk power and distribution systems. On the utility side of the meter, power quality monitors, substation instrumentation, faulted circuit indicators, phasor measurement units, advanced meters, and other devices are providing data to system operators and planners.[178] On the consumer side of the meter, products such as grid-connected inverters, thermostats, appliances, and machines are increasingly connecting to each other and to the internet or the IoT. The interplay of these various devices on the grid through the IoT is generating dramatically increased volumes of data. Grid operators and power dispatchers need better visualization of behind-the-meter resources for capacity planning and grid operations. Grid operators also need to understand the degree to which they can rely on customer-sited assets' power production to offset capacity requirements.

One meta-analysis estimated that the effective use of ICT has the potential to reduce total U.S. energy consumption by 12 to 22 percent by 2020.[179] While ICT devices consume electricity, they also increase economic productivity and can improve energy efficiency. For every kWh consumed by ICT systems, it has been estimated that 10 kWh are saved elsewhere in the economy.[180] However, deployment of ICT, AMI, and grid communication infrastructure also raise issues concerning data privacy, ownership, and access.

The broader community served by the utility may increasingly use utility communications networks—a convergence of systems that can create new value to the economy. For example, Chattanooga's municipally owned utility, the Electric Power Board (EPB), built a fiber network throughout its service territory to offer the fastest broadband service to its customers and to enable a smart grid system that would save energy and be more reliable.[181] EPB installed fiber optics throughout its service territory, including rural areas at the end of distribution lines, which enabled EPB to automate control of its distribution and subtransmission systems.[182] In 2009, DOE awarded EPB $111.6 million through the Smart Grid Investment Program, funded by the American Recovery and Reinvestment Act, to install 170,000 smart meters and grid-automation technologies to improve reliability and reduce consumer electricity bills through energy savings.[183] The upgraded system has already allowed EPB to quickly restore power after two major weather-related outages, saving millions of dollars for EPB and the community.[184]

In 2010, EPB announced it would offer the first 1-gigabit-per-second (Gbps) service in the country, which is 10 to 20 times faster than the broadband EPB had been offering.[185] The availability of 1-Gbps internet service has helped grow Chattanooga's economy and encouraged businesses to invest in the city.[186] The Federal Communications Commission (FCC) has attempted to remove barriers to broadband expansion and promote competition in Tennessee by allowing EPB to expand outside its service area; however, a Federal appeals court recently held that the FCC did not have authority to do so.[187]

According to the FCC, 10 percent of Americans and 39 percent of rural Americans lack access to advanced telecommunications.[188] The Federal Government, through the Rural Electrification Act, has a long history of expanding access to affordable electricity and communications services in rural America.[189] The Federal Government has also supported granting loans to rural electric co-ops at interest rates that allow them to achieve rural electrification goals—including improving electricity generation, transmission, and distribution facilities in areas with high electricity costs.[190, 191] USDA's RUS administers these electricity financing programs and also finances rural investments in broadband and smart grid technologies. Coordinated expansion of electricity and broadband infrastructure in rural America, supported by Federal financing from RUS, would serve the dual purposes of increasing access to advanced telecommunication technologies and improving the functioning of rural utility systems.

Customer Engagement with New Electricity Services

As discussed in Chapter I (*Transforming the Nation's Electricity System: The Second Installment of the Quadrennial Energy Review*), the electricity system is becoming more digital, connected, and integrated. These trends, and the new services and assets on the system including distributed energy resources (DER), home automation, and DR, are changing the physical electricity system, while also altering customers' interest and engagement with their energy use. One study of grid modernization found that consumers with a smart meter in their home expect more from their utility in terms of notifications on potential bill savings or excesses.[192] While many customers will continue to desire "plain vanilla"[193] electricity service, increasingly, utilities are working to better engage and inform their more energy-involved customers and are moving toward more customer-centric business models.

Engaging customers has distinct benefits for utilities—engaged households add $40–$90 annually to a regulated utility's bottom line (Table 2-1), and residential customers report up to a 9 percent increase in satisfaction with their utility.[194] Utilities further benefit from robust customer-engagement initiatives as the grid and the utility business model continually evolve and modernize to meet new technology demands, system changes, and policy goals. Utilities with more satisfied customers are more likely to be approved for rate increases for new investments than those with lower customer-satisfaction ratings.[195] According to a survey of 144 power sector executives, only 2 percent think their utility has good customer outreach programs,[196] but more utilities are investing in new market and communications programs and technologies. Increasingly, low-touch interaction, self-service, and social media engagements are three common customer preferences for interacting with their utility.[197] These engagements can include smart phone applications for real-time monitoring of home energy use and e-billing for monthly electricity bills.

Table 2-1. Potential Annual Cost Savings from Customer Engagement Solutions[198]

Value Source	Annual Savings Per Regulated Household
Effective marketing of new offerings	**$4–5**
Reduced cost-to-serve	
Reduced call volume, decreased escalations, etc.	$3–16
Increased adoption of e-billing	$3–5
Improved payment discipline	$1–4
Improved cost-effectiveness of energy efficiency (EE) program portfolio	
EE program cost savings via Behavioral EE	$2–5
EE program cost savings via Thermostat EE	$20–35
Behavioral DR capacity and energy cost savings	
Behavioral demand-response capacity savings	$7–20
Potential aggregate value, $/household, per year	**$40–90**

Customer engagement can provide cost savings to utilities across several functions: program marketing, customer care, energy efficiency, and demand response.

Privacy Concerns Could Limit Utilization of Consumer Data

Policymakers, utilities, and third-party providers must address privacy considerations as the amount of data generated about consumers' electricity usage grows. For residential consumers, concerns revolve around control of when, where, how, and with whom an individual shares his or her own personal information, as well as the right to access personal information given to others, to correct it, and to ensure it is safeguarded and disposed of appropriately.[199] Other aspects of privacy include privacy of the person, privacy of personal behavior, and privacy of personal communications.[200] Some consumers are resistant to AMI due to the specificity of data collected on energy-use data in smaller and shorter time increments. For example, actual appliances can be identified by their load profile (refrigerator, toaster, washing machine, kettle, plasma TV, oven, etc.) and times of usage. These data can reveal building occupancy, behavioral patterns, and individual preferences.

Privacy concerns are not limited to residential consumers. Smart buildings may adjust building controls, including HVAC, lighting, and security systems based upon occupancy levels and occupancy migration throughout the building. Larger commercial and industrial customers may have legitimate concerns about similar data usage, such as knowing how much and when a specific type of the customer's equipment is operational, is being intercepted, or is available to their competitors. Competitors, potential suitors, and even astute investors could be keen to learn facility utilization, production rates, and other salient operational details before such information becomes public after products' sales volumes are announced or disclosed. Similarly, governmental customers, especially national defense agencies or their contractors, may have concerns about unfriendly parties or foreign governments understanding an agency's or contractor's grid vulnerabilities and requirements, usage, and patterns.

Launched in 2012 by the Federal Government, the Green Button Initiative[201] is a partnership with the electric utility industry to provide consumers with easy, secure access to their own energy-usage information in a consumer-friendly and computer-friendly format.[202] More than 60 million households and businesses can utilize Green Button to access energy-usage data from their electric utility. While this program provides individuals with their own energy-use data, streamlined sharing of data with third parties, as exists with global positioning system (GPS) data, is still not available. The 2016 Orange Button program builds on Green Button and establishes solar data.

DOE has published a voluntary code of conduct for data privacy related to end users' energy-consumption data. Utilities can demonstrate their commitment to customers' data privacy through voluntary adherence to the DataGuard Energy Data Privacy Program's standards. These standards ensure customers and regulators that individuals who use customer data adhere to a minimum and well-articulated level of data privacy. A company's claim of adherence to the DataGuard principles is enforceable by the Federal Trade Commission and state consumer-protection agencies.

Demand-Side Options Can Be Used to Avoid Costs of New Infrastructure

Many utilities are facing the prospects of large capital investments in transmission and distribution system upgrades. The Edison Foundation projects that total U.S. distribution capital investments for the period 2010 to 2030 will be $582 billion in nominal terms.[203] Geographically targeted energy efficiency and DER have the potential to cost-effectively defer, reduce, or replace capacity upgrades for distribution and transmission systems by reliably reducing maximum demand in specific grid areas and increasing utilization of existing assets. In addition to cost savings, potential benefits of non-wire alternatives include mitigating siting concerns related to transmission lines; engaging consumers and their agents (e.g., aggregators) in distribution and transmission solutions; enabling gradual implementation (reducing the impact of incorrect load projections); improving reliability and resilience through a diversity of measures; and accelerating development time frames. These alternatives can be identified through distribution and transmission planning for specific geographic areas. Orders 890 and 1000 by FERC (discussed in greater detail in Chapter III [*Building a Clean Electricity Future*]) require transmission providers to comparably treat all resources in a transmission planning process. For example, transmission providers may have to identify how they will treat demand resources on a comparable basis with transmission and generation solutions for purposes of transmission planning.[204, 205, 206] The Bonneville Power Administration and some states (e.g., Maine and Vermont) and utilities have been early DER adopters.

The Brooklyn Queens Demand Management project is an example of a utility plan using demand-side options, along with utility resources, to avoid spending $1.2 billion for new substations, feeders, and switching stations to meet a 69-MW shortfall in the growing Brooklyn and Queens boroughs of New York City. Consolidated Edison's (ConEd's) Brooklyn Queens Demand Management project will cost an estimated $200 million, which includes 17 MW of infrastructure investment and 52 MW of demand-side solutions on both the utility and customer sides of the meter. Demand-side options include energy efficiency programs with residential and commercial customers, DR auctions, and a CHP-acceleration program. ConEd held its first DR auction in early August 2016 and awarded 10 contracts that would result in 22 MW of peak demand reductions in 2018. Payments to providers ranged from $215–$988/kW/year depending on the amount of power reduction and demand management technology used. The awarded companies are responsible for signing up ConEd customers who are willing to reduce their usage during peak hours or deploy technologies like solar or storage to cut their consumption. The utility will also be deploying several DER, including solar generation, fuel cells, battery storage, and voltage-optimization technology, to reduce peak demand and save energy.

More than 250 electric cooperatives in 35 states use large-capacity electric-resistance water heaters to shift demand away from peak hours.[207] These large, insulated water heaters store water heated with low-cost power during times of off-peak demand for use during times of high-cost peak energy demand, enabling co-ops to optimize operation of the grid. Large water heaters also contribute significant and consistent amounts of load, making them ideal candidates for utility DR programs.[208] Basin Electric Co-Op, which relies on these larger water heaters for many DR programs, estimates that these grid-tied water heaters help reduce 500 MW of annual peak demand in the United States.[209]

The application of DER to offset traditional system upgrades presents a new value proposition and challenges how utilities are typically compensated. According to the New York Reforming the Energy Vision order on ratemaking and the utility revenue-model framework,[210] the New York Public Service Commission expects that new earning opportunities for utilities in the near term will be a combination of outcome-based incentives and revenues earned directly from the facilitation of consumer-driven markets.

Aggregation of Individual Consumer Transactions Can Create Economies of Scale and New Business Models

Aggregation can be of either load (i.e., consumers joining together to aggregate purchases of electricity) or of some combination of supply and demand side resources. Changes in technology as well as state policy have led to the evolution of two newer forms of aggregation, in addition to DR: virtual power plant aggregation and community choice aggregation.

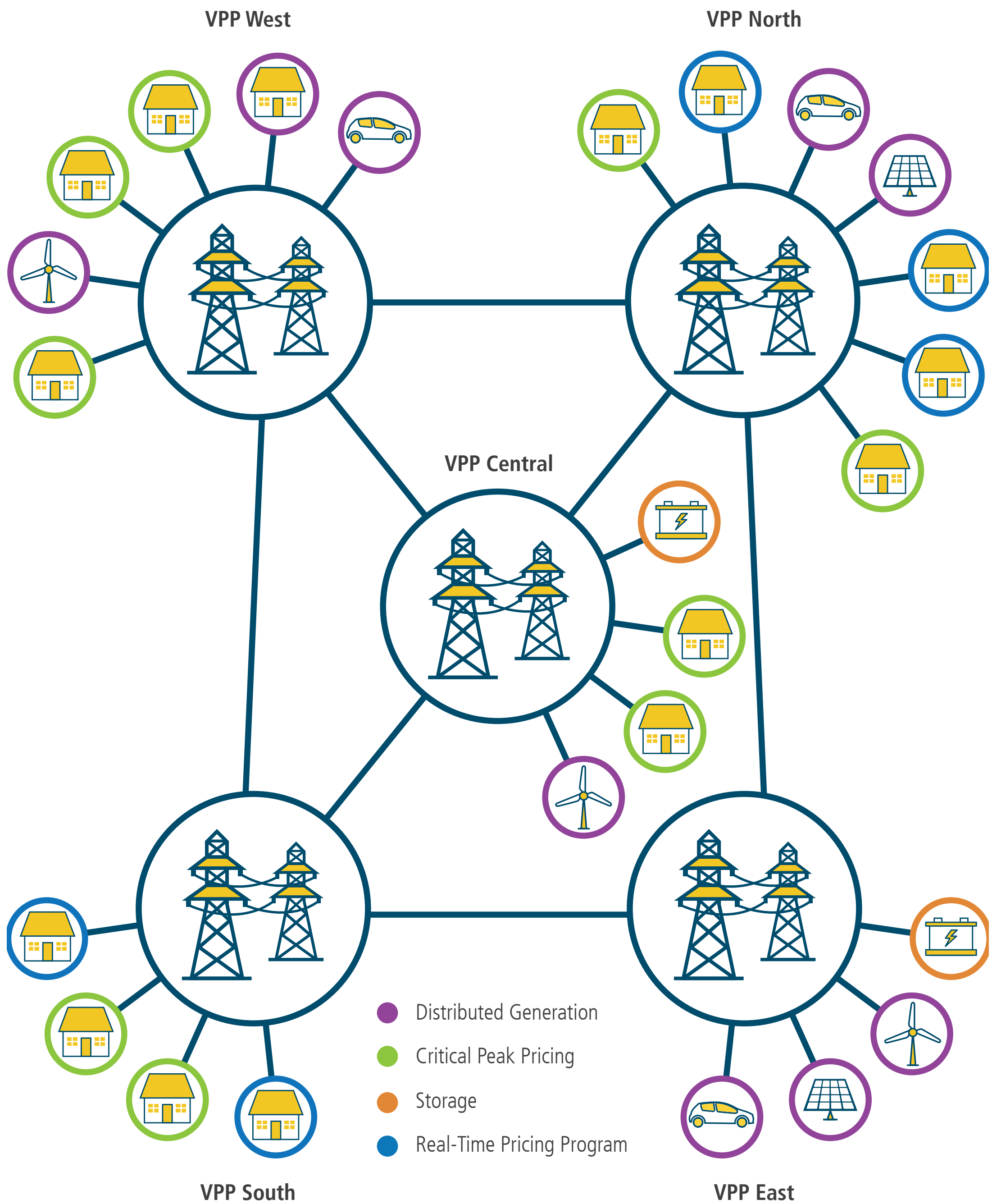
DR aggregation is being pursued by both electric utilities and companies, who then take the aggregated DR and bid it in RTO/ISO wholesale markets, such as PJM, ISO New England, Midcontinent ISO, California ISO, and New York ISO, or deliver it to contracted utilities.[ae] DR in these wholesale markets helps lower wholesale prices and adds to resource diversity, which can help reliability and help integrate other resources such as wind and solar. One estimate is that 32 GW of DR resources are now available, all of which are bringing the customer directly into wholesale electricity markets.[211]

The use of aggregated DR in RTO/ISO markets was greatly aided by FERC's issuance of Order No. 745, which said that a "demand response resource *must be compensated* for the service it provides to the energy market at the market price for energy, referred to as the locational marginal price."[212] Since there is a mixing of retail-level services with wholesale-level services, FERC's Order No. 745 raised a number of state and Federal jurisdictional issues, which the Supreme Court addressed.[213]

Virtual power plants (VPPs), pioneered in the 1980s in Austin, Texas, are systems that integrate a wide variety of power resources, such as smaller, local renewable or gas-fired generation, energy storage, and energy efficiency DR programs. They do this by aggregating many diverse customers from different customer classes "under one type of pricing, demand response, or distributed energy resource program."[214] Customers are not necessarily grouped by program or type, but they can also be aggregated by another defining characteristic, for example, location (Figure 2-14). By remotely controlling these VPPs and aggregating different types of products, utilities are able to better forecast energy supply and demand and increase the flexibility and reliability of the system. In addition, aggregation of DR programs allows participation in a wholesale market. Utilities in several states are beginning to focus on today's newer version of VPPs. In Kentucky, for example, the Glasgow Electric Plant Board is installing a system of batteries that can release power during peak demand times.[17] Similar programs are being piloted in New York and Vermont.[18] Today, technology and ICT are enabling the consideration of more elaborate forms of VPPs.

[ae] Chapter III (*Building a Clean Electricity Future*) discusses states regulatory actions that impacted DR.

Figure 2-14. Aggregations of Demand Response and Distributed Generation[217]



Aggregators acting as VPPs collect power and services from distributed resources, including community solar, rooftop solar, EVs, distributed storage, and grid-controlled and price-reactive household devices. Aggregators are then able to bid these services collectively into wholesale electricity markets to meet system operation needs.

Community choice aggregation (CCA) enables local governments to aggregate the buying power of individual customers in order to secure alternative energy supply contracts on a communitywide basis, while maintaining the existing electricity provider for transmission and distribution services.[218] Seven states—Massachusetts, New York, Ohio, California, New Jersey, Rhode Island, and Illinois—passed CCA laws as part of electric-restructuring legislation in the late 1990s and early 2000s. In 2013, CCAs were able to secure more than 9 million MWh of renewable energy for approximately 2.4 million customers. Most CCAs are "opt-out" entities, meaning that the customer is, by default, part of the aggregation unless the customer opts out.

The **community solar model** is an additional method of organizing the installation of solar facilities. In this structure, solar facilities supply power to multiple customers, enabling the placement and sharing of solar installations by a diverse group of customers. This model is mentioned separately because it can be developed via multiple ownership forms, including joint, municipal, and utility.

Interconnection and Interoperability Standards

Interconnection standards—the sets of rules that determine the requirements for DG or storage to connect to the distribution grid—prescribe the capabilities that technologies must possess in order to be allowed to interact with the grid. These standards are voluntary, but many state PUCs require their jurisdictional utilities to adopt them and thus have become de-facto industry standards.

In 2013, the Institute of Electrical and Electronics Engineers (IEEE), which authors the standards, launched a full revision of its Standard 1547 "Standard for Interconnecting Distributed Resources with Electric Power Systems," with experts at National Renewable Energy Laboratory and Sandia National Laboratories leading the Standard Technical Panel.[219] The revision, which is currently underway, should clarify functions for distributed storage, DR, interoperable backup generation, and distributed PV related to advanced inverter functionality, communications capabilities, controls, and interoperability, among other topics. These capabilities are foundational for using distributed storage, backup generation, and PV generators to support the functioning of the grid in the long term. In the short term, they will enable greater hosting capacity and mitigate some integration challenges.

The primary challenge to completing the interconnection standard, known as IEEE Standard 1547 revision, is circulating the proposed revised standard throughout the industry and arbitrating comments through the ballot process. If the average monthly rate of distributed solar PV adoption from April 2015 to April 2016 remains the same, an additional 10 GW will be added to the grid by the end of 2018, more than doubling the current capacity.[220] However, even after IEEE adopts the revised standards, PUCs and utilities will need to consider and adopt them in order to facilitate advanced interconnected and interoperable operation of grid-connected devices. Notably, the current published standard (1547.a) encompasses aspects of extended interoperability capabilities,[221] but it has not been widely adopted. Expediting the completion and adoption of the 1547 Standard revision will improve some operational characteristics of pre-existing systems. It will also allow a greater percentage of near-term capacity additions to incorporate many important grid functions and capabilities that current standards do not address.

In addition to IEEE standards, National Electrical Code standards for grid-connected devices have changed significantly with each update to the standards in recent years. This change has been in response to the continued evolution of solar technology and the need for a stable market environment to ensure the proliferation of safe, reliable, and cost-effective solar PV.

Interoperability is also a critical requirement for seamless integration of grid-connected devices.[222] The National Institute of Standards and Technology (NIST) defines interoperability as "…the capability of two or more networks, systems, devices, applications, or components to exchange and readily use information—securely, effectively, and with little or no inconvenience to the user."[223] Interoperability standards increase the cost-effectiveness of grid-modernization investments by mitigating the risk of diverse grid technologies becoming prematurely obsolete; accounting for backward compatibility with already deployed technologies; enabling technology innovations for the hardware and software of grid-connected devices; and ensuring the security of devices connected to the grid.[224] The Energy Independence and Security Act of 2007 mandated that NIST develop a framework and protocols for interoperability standards of smart grid devices. NIST, in cooperation with the industry-led Smart Grid Interoperability Panel, developed initial standards and continues to develop standards with the participation of DOE and industry groups.

The Federal Government does not mandate the uptake of interoperability and interconnection standards, but it supports and can speed up the development processes for standards in order to animate national markets for grid-connected devices. Many consumer-level and grid-level devices are either on the market or under development. When connected through electric utilities' distribution grids, these devices can offer benefits to the customers who use them and can support the stability of the broader grid system. However, in order to realize benefits, devices must be able to coordinate and communicate their operations with the grid operators' control systems and other devices.

The Changing Preferences of Electricity Consumers: Impacts on Rates and Business Models

The new grid and end-use technologies described in QER 1.2 have different operational characteristics and can provide new and different grid services. In many instances, these new technologies can provide benefits to the grid but do not necessarily provide essential reliability services; this raises cost-benefit issues and points to the need for adequate valuation of new consumer options.

Vertically integrated utilities provide the full range of grid services (energy, ancillary services, etc.) necessary to ensure reliability for the consumer. With the advent of competitive markets, energy and other services can now be acquired from other utilities and third-party providers. Despite increasing customer participation, the responsibility of ensuring reliability on an increasingly complicated system falls to the grid operator.

The proliferation of dynamic, consumer-owned assets that generate power and provide DR services also presents challenges to the Federal and state regulatory structures that govern compensation for energy infrastructure and grid services. In addition, state and local electricity regulators and policymakers are working to both sustain and transform an industry where there are new technologies, consumer demands, and regulations. Public officials and small utility managers are working to evaluate the costs and benefits of emerging technologies. This process is often highly technical and demands a significant, changing knowledge base and skill set. Also, new compensatory models to incent the appropriate mix of resources on the grid and new tools for coordinating across jurisdictions will be required to align the policy and regulatory frameworks that ensure secure, reliable, and affordable electricity.

Compensating Providers of Grid Services

The accurate characterization and valuation of services that new technologies provide to the grid can contribute to clearer price signals to consumers and infrastructure owners. This clarity ensures that tradeoffs among system attributes like affordability, sustainability, and reliability are systematically considered, and that desirable properties are compensated appropriately in a rapidly evolving system. Utilities are increasingly attempting to quantify the relative cost of demand-side energy efficiency and load-management investments compared to supply-side, transmission, or distribution investments in utility and regional planning processes, as well as interconnect-wide and national policy making.[225, 226, 227, 228] Often, investments in demand-side energy efficiency to balance supply and demand on the electricity system are less expensive than additional supply and provide a range of quantifiable benefits.[229, 230] However, current methods for considering benefits of and procuring energy efficiency differ from supply-side investment decisions, including how participant costs are considered and the ability of a utility to acquire resources outside its service territory to meet demand.[231]

Valuation of Grid Services

There are gaps in how markets, incentives, and regulations compensate and value services provided by emerging technologies and system topologies. Closing these gaps often requires specific efforts to address finance, market rules, incentives, and policies. While valuation continues to be a high-level discussion in the electricity sector, opportunities exist to fill current, clearly defined gaps related to the environmental, reliability, security, and resilience benefits of new services.

The value that new energy resources provide, both individually and in aggregate, depends on the following:

- **Type of resource:** Different resources will be able to provide different values in different situations. For example, while energy storage and PV will be able to provide reactive power to the grid, other devices (e.g., efficient windows) will not.
- **Location:** The value that a resource can provide depends on its location on the distribution or transmission system. For example, placing efficiency measures on PV near points of congestion may have much more value to the electric grid than places with no congestion.
- **Time:** When the resource provides the service is important. For example, if energy efficiency measures reduce periods of peak load, those measures may be able to defer building new generation or distribution/transmission upgrades.

Currently, many valuation efforts focus on the contributions of specific energy technologies, but to be fully effective, valuation must be done in a system context, and estimating the value of an individual technology outside the system context is suboptimal.[232] Changes to the system, whether regulatory changes or technology changes, can have both locational and temporal system impacts. Quantifying the value of an individual technology should involve comparing the states of the system before and after the technology was installed.

Rate Designs for Valuing New Services

Electricity rates are the schedule of prices that utilities charge end users for the provision of service. Ratemaking, the process of establishing rates, is an administrative process designed to recover expected costs and provide the utility an opportunity to earn an allowed rate of return. Through cost-of-service rates, utilities earn a fair return on invested capital and recover the cost of depreciation, operating expenses, and taxes. Additionally, the recovery of costs in ratemaking introduces behavioral incentives to utilities. The structure of electricity rates determines the nature of price signals to consumers. Rates are the primary mechanism by which utilities provide information to customers to inform their consumption and investment behavior. Supreme Court precedents that frame the legal requirements of regulation help shape ratemaking.[af]

[af] For example, in *Knoxville v. Knoxville Water Company, 212 U.S. 1 (1909)*, the U.S. Supreme Court recognized the right of a utility to recover the initial cost of infrastructure investment through depreciation charges. In *Bluefield Water Works & Improvement Company v. Public Service Commission, 62 U.S. 679 (1923),* the U.S. Supreme Court established the principle that "the return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate…to maintain and support credit…"

The ratemaking process begins first with the determination of the utility revenue requirement and follows with the design of rates. The revenue requirement is a forecast of the budget that the utility will require to meet expected customers' electricity needs during a past or future test year. The basic formula for determining the utility revenue requirement is:

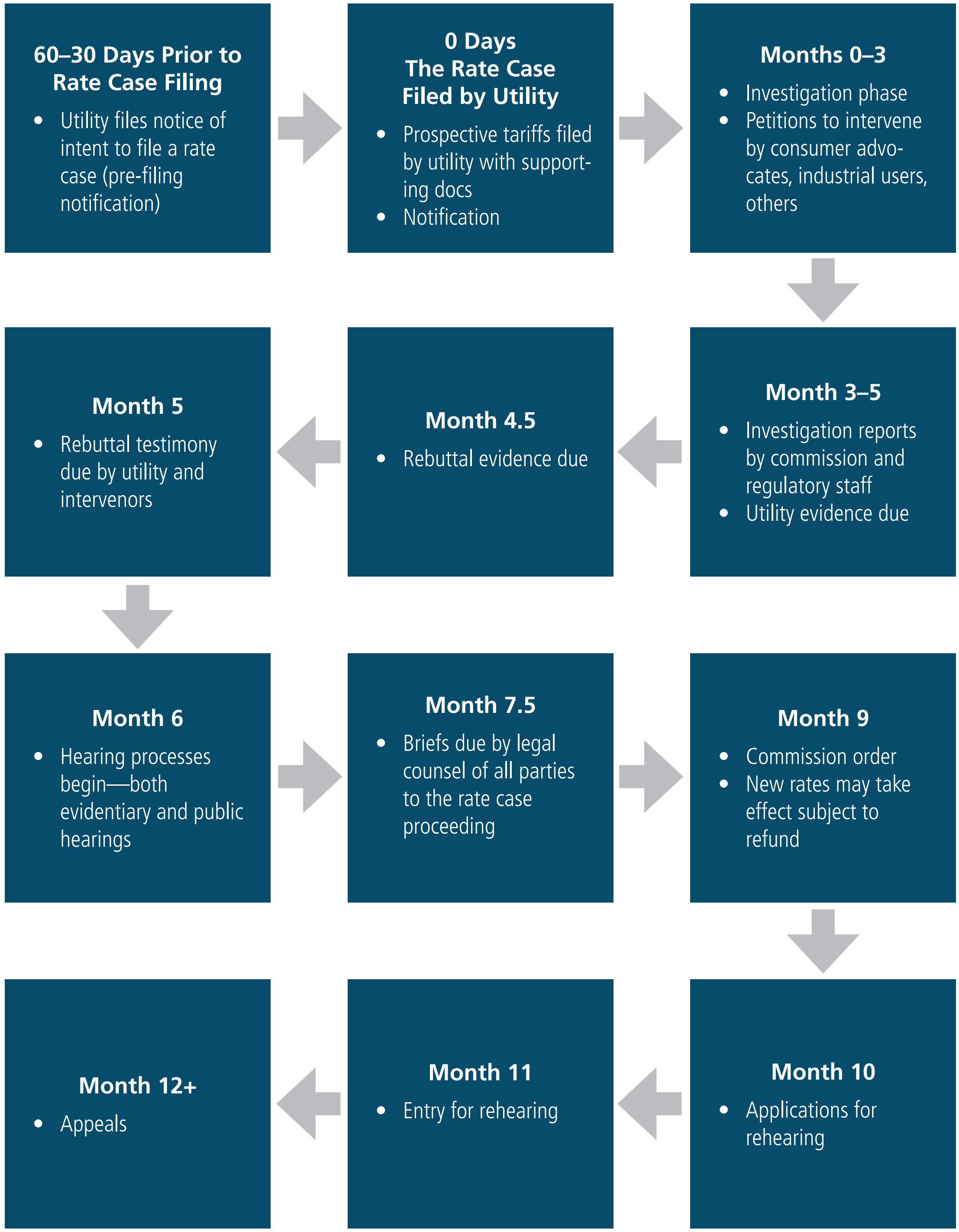
$$\textit{Revenue Requirement} = (\textit{Rate of Return} \times \textit{Depreciated Rate Base}) + \textit{Depreciation}$$
$$+ \textit{Operations and Maintenance (including Fuel)} + \textit{Taxes}$$

The rate-design process balances the prices customers see with the utility's ability to recover its revenue requirement. The process requires allocating utility costs to different customer classes (e.g., residential, commercial, industrial) and to different rate categories (e.g., energy charges, demand charges). A key step in the rate-design process is the determination of cost causation (the underlying rationale for incurring that cost), which helps develop rates whereby different customers pay the cost of providing the service they use. Various elements of costs (e.g., distribution costs, metering, and transmission) are thus allocated to each customer class. Ideally, each customer would pay only the cost of providing services that the customer uses. As discussed, this is an aspirational goal that utilities often do not achieve in practice.

Some jurisdictions may have rates in effect for a specific time period, such as 3 years, while other jurisdictions may allow rates to remain, in effect, indefinitely, unless the utility, the PUC, or a third party with standing seeks a rate adjustment via a complaint.

Considerations include the needs of current versus future ratepayers; the geographic or demographic characteristics of ratepayers; funding for any public benefit programs, like efficiency, R&D, or low-income assistance programs; evolving technology; and social goals like environmental performance. Figure 2-15 on the folowing page illustrates the order and timeline of a typical state rate-case proceeding.

Figure 2-15. Timeline of a Typical Rate Case Proceeding



Rate cases are lengthy and complex, often lasting a year or more. Depending on how utilities calculate their costs, this often leads to "regulatory lag," wherein rates come into effect long after utilities have made investments. Thus, utilities are typically recovering past, not current, costs.

Typically, the rate-design process begins with a cost study that characterizes the elements of the utility's cost for providing service to customers and determines cost causation. Note that the *costs* of providing service are the quantifiable values of assets and policies that accrue to the utility; the *price or charge* is the cash value of the service determined by rate regulation, including subsidies—the utility recovers *costs*, while the customer sees *prices and charges*. Elements of cost fall into three basic categories:

1. **Fixed costs** are the basic costs of providing service that do not vary with the level of electricity consumption. An example of a fixed cost is the cost of a meter, a necessary element for providing service that is functional whether the customer uses very little or a great deal of energy.
2. **Capacity costs** measure the impact of usage on system infrastructure, where increases in customer consumption can trigger the need for additional investment. For example, increases in air conditioning use can necessitate distribution investment, where the size of a substation supporting a residential distribution lateral power line is driven by the need to reliably serve the peak usage, typically propelled by air conditioning on the hottest day of the year. Capacity (demand) charges can be designed to signal customers' expected contribution to new investment and provide a mechanism for recovering those costs, once incurred.
3. **Variable costs** are primarily the energy costs associated with providing a service, such as fuel. Variable costs change based on the customer's electricity demand and the types of generation capacity available in the system.

In an ideal ratemaking scheme, the elements of cost would fit naturally into the three components of rates: (1) fixed (customer) charges, (2) capacity (demand) charges, and (3) energy (variable) charges. The fixed customer charge would reflect the fixed costs of providing a service. The variable energy charge would represent the cost of energy, determined either through an electricity market or by the fuel and other variable costs required to operate the utility's own generation. Capacity costs vary by demand and are driven by the maximum system usage because electrical systems are designed to meet peak energy consumption. The demand charge is a mechanism for both recovering capacity costs and providing a price signal to customers about their contribution to costs at the peak. Typically, the demand charge is set annually, serving as a ratchet on the customers' bills.[ag]

Traditionally, utilities recouped their costs from customers by charging a two-part rate that consisted of a volumetric charge component and a fixed charge component. Volumetric charges are based on the amount of electricity a customer actually uses and generally are assessed per kWh. Customers pay the fixed charge regardless of how much electricity they consume.[ah] Analysts have generally broken down the fixed costs that the utility incurs into two categories: system-wide fixed costs and customer-specific fixed costs. A customer-specific fixed cost is the cost the utility incurs when it is servicing the customer—for example, the costs to meter the customer and issue a bill. This cost is independent of the customer's usage. A system-wide fixed cost is the cost of having, running, and maintaining the electricity grid—regardless of how many customers it is serving.[233] Historically, consumer demand allowed utilities to securely recoup most of their fixed costs through

[ag] A ratchet is a circumstance in which the rate will not decline until an appropriate period elapses (often, 1 year). Thus, a demand charge, based on a demand of 3 kilowatts set in month one (say, January), might increase if a higher demand, 5 kilowatts, for example, is set in month two (February); but lower demand in subsequent months will not reduce the demand charge until the period has expired.

[ah] Fixed charges may vary by class of consumer—industrial, commercial, or residential—but the volume of usage per billing period may not determine the classes.

the volumetric rate. Utilities were able to assess only a limited fixed charge to each customer, which generally did not accurately reflect the true fixed costs that a utility was incurring. For typical residential customers, fixed costs make up a much larger proportion of total costs for utilities than the customer's electricity bills reflect.[ai]

While consumers only see a small fixed charge on their electricity bill and most of their bill comprises the variable charge based on the electricity consumed, utilities' costs do not reflect this breakdown. Utilities' costs for a typical bill are divided into variable and fixed costs. Although, historically, customer demand allowed utilities to securely recoup most of their fixed costs through the volumetric rate, the current stagnant or declining demand is causing utilities to undercover fixed costs.

However, the current trend of stagnant or declining demand and the resulting drop in revenue from volumetric charges has rendered this strategy ineffective, leaving utilities to find new methods to recover their fixed costs. Some utilities have proposed converting system-wide fixed costs into fixed charges to consumers, but this is not without controversy. As the Rocky Mountain Institute concluded: "If increasing portions of customer bills are collected in the form of fixed monthly charges—and less in the form of volumetric charges or other types of charges that the customer has the ability to influence—the incentive to conserve could be diminished."[234] However, raising fixed costs for all customers can disproportionately impact low-usage customers for whom high fixed costs would comprise a relatively larger portion of the bill. High fixed costs similarly impact low-income customers and other vulnerable populations.[235]

Time-Varying Rates Can Shift Demand

Historically, volumetric charges to end users have been uniform in time, but system costs vary by season and by hour of day, reflecting the marginal cost of generation, the cost of maintaining capacity, and impacts on congestion on physical infrastructure. Time-varying pricing is one way to induce consumers to shift their demand to less-expensive times, and it has the potential to shift value from owners of generation assets to consumers.[236, 237] Variations in consumer prices can be scheduled in advance or can reflect real-time wholesale energy prices. The most common time-varying rate is time-of-use (TOU) pricing, which uses a predetermined schedule of seasonal and daily price variations. Some utilities are moving toward implementing TOU as the default rate.

TOU pricing usually does not reflect the small number of hours that have the very highest wholesale prices and congestion problems. Two rate structures that do reflect those times are real-time pricing (RTP), through which consumers experience wholesale prices directly, and critical peak pricing, which gives consumers occasional large rate jumps at short notice when system costs are particularly high. RTP provides the most economically efficient incentives, and it could increase the economic efficiency of the system substantially. One estimate found that increasing the number of PJM customers on RTP from 10 to 20 percent could improve economic efficiency by $120 million per year.[aj, 238] However, RTP and critical peak pricing introduce the risk of volatile wholesale prices to the consumer, though financial instruments can mitigate risks.

Consumer advocates have opposed time-varying pricing on the grounds that it disadvantages low-income residential consumers, but there is not clear evidence to support that claim. A survey of multiple TOU programs found low-income consumers to have both flatter demand profiles and less ability on average to

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[ai] "A typical residential customer uses 982 kWh of electricity per month, with a bill averaging $110. The bill is made up of three cost components: $70 can be allocated to generation, $30 to distribution, and $10 to transmission. Nearly all the distribution and transmission costs are fixed (or capacity-type) costs that do not vary based on hourly customer loads, while approximately 80 percent of generation costs are variable. This means that $54 of the typical bill is related to capacity or fixed costs, and $56 can be attributed to energy-related or variable costs. Yet, a typical residential fixed charge is around $10 per month." Source: Paul Zummo, *Rate Design for Distributed Generation: Net Metering Alternatives* (Washington, DC: American Public Power Association, 2015), 3, http://www.publicpower.org/files/PDFs/Rate_Design_for_DG-_Net_Metering_final.pdf.

[aj] For comparison, the total retail price of electricity transacted through PJM in a year is about $60–70 billion.

shift their demand in response to price.[239] This meant that, on average, low-income consumers benefitted from TOU without any change in their behavior. However, they were less able than other consumers to recoup additional benefits by changing behavior. Across the five TOU programs studied, the net effects on low-income consumers could be positive or negative.[240]

Locational Pricing Difficult to Implement

Traditionally, locational impacts on electricity cost do not inform retail rates, which is analogous to uniform charges at the post office for mailing a letter to an urban or a rural home. Whether living in a dense urban neighborhood or in the only house at the end of a country road, all consumers in a service territory pay the same charges for the distribution system. However, system planning and operations are now reaching a level of sophistication that allows engineers to estimate the locational and temporal costs of electricity depending on the localized technical attributes of the physical distribution system like feeder infrastructure, line constraints, and local demand.

Recent policies from several state PUCs have suggested regulatory interest in location-based pricing for ratepayers down to the feeder level. Regulators in Minnesota currently allow utilities to incorporate the location-specific net benefits of DG into prices charged for particular ratepayers.[ak, 241] Regulators in New York, Hawaii, and California have recently expressed interest in location-based rates.[242, 243]

However, most determinants of locational value are not within customers' control, or even within the consumer's knowledge. For example, if a secondary transformer is close to its reserve margin and someone who lives nearby buys an EV, the utility may have to upgrade the transformer, incurring a very substantial local cost. If that utility is applying locational prices, all of the customers on that feeder would see their prices go up in response to one neighbor's decision. Locational costs may reflect physical geography, local economic characteristics, and legacy planning decisions made by utilities, and these complexities introduce opportunities for inequities to consumers. A feeder-by-feeder economic and engineering analysis of the value of distributed PV in Pacific Gas & Electric Company's service territory found that 90 percent of feeders had neither costs nor benefits from distributed PV. The analysis also found that the highest locational value on any feeder was only about $60 per kW per year, suggesting that there may be limited benefit to instituting locational prices.[244]

Net Metering for Distributed Generation

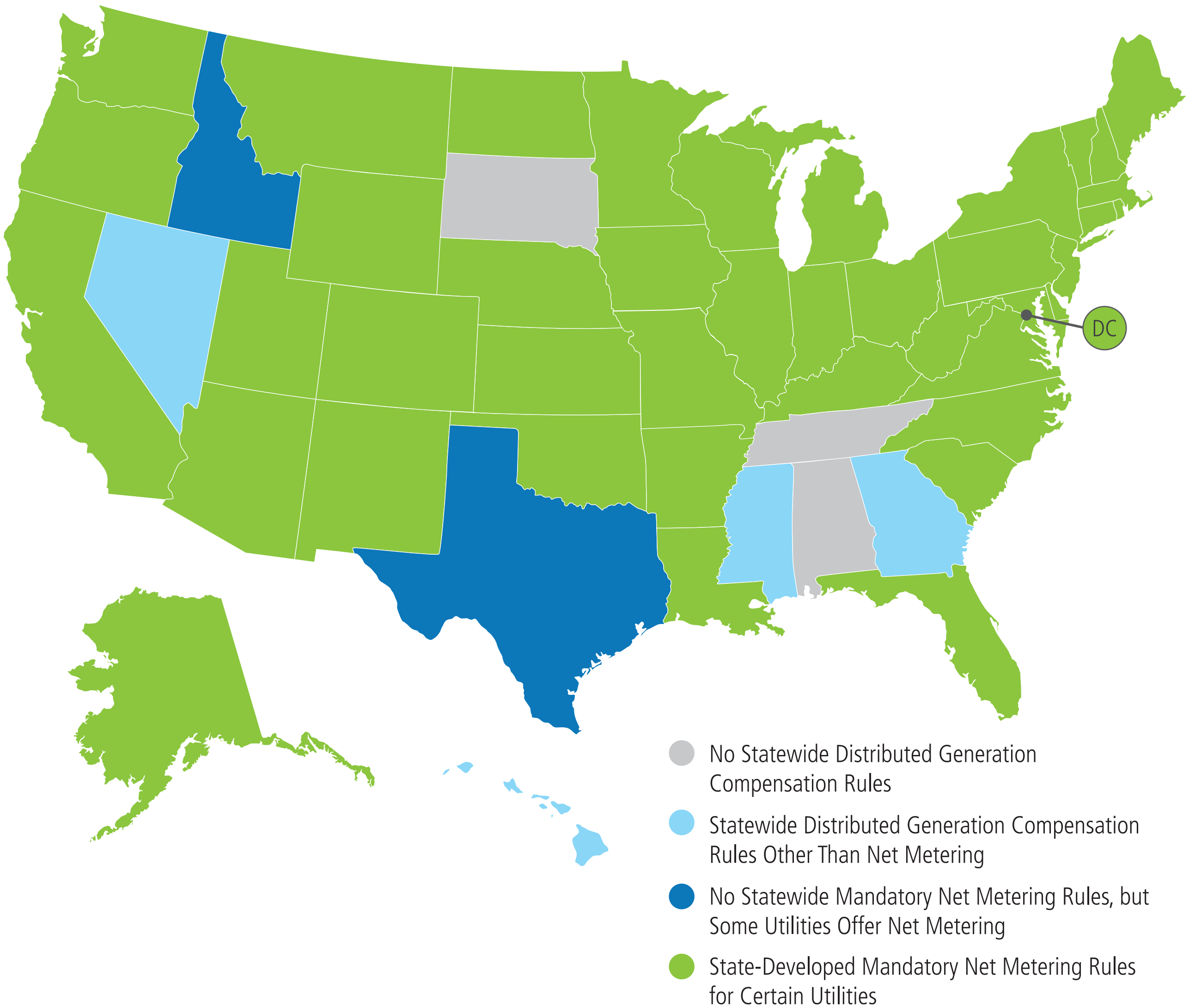
Net metering is a rate mechanism wherein customers with onsite generation like rooftop solar are charged for the value of their net consumption (electricity consumed less electricity produced by solar), crediting onsite generation at the full retail rate. A provision in the Energy Policy Act of 2005 required states to consider net metering as an option for compensating owners of DG. Currently, 41 states and the District of Columbia have a statewide net metering policy, and 6 states have alternative compensation mechanisms for DG (Figure 2-16). States that adopted net metering policies were likely motivated by a desire to generate electricity from zero- or low-emitting sources, to support deployment of a new technology, and to give consumers the option of generating their own power.[245] As of September 2016, the policy has contributed to the deployment of 12,300 MW of installed distributed PV in the United States.[246]

Consumers with DG are still connected to the main grid, allowing them to benefit from the physical connection to the grid that provides balancing services, reliability, and base load and peaking generation for electricity when the DG source is not producing electricity. In addition to onsite PV hosts, many utilities have expanded net metering to customers who participate in offsite solar generation, such as community

[ak] The Minnesota Value of Solar Methodology allows for incorporating the location of the DER in determining its value to the grid, but it is not clear that utilities have actually exercised that discretion.

solar, through virtual net metering.[al] Such programs extend the bill savings to consumers who do not have appropriate space for solar on their own premises or who are unable to finance solar on their own (e.g., low-income consumers).

Figure 2-16. Current Net Metering and Distributed Generation Compensation Policies[247]



Georgia, Hawaii, Mississippi, and Nevada offer alternative compensation mechanisms for DG such as net billing, which typically provides a rate of compensation for grid exports below the retail rate.

There are a wide variety of methods for valuing DG. Net metering values DG at the retail rate. At low penetration levels and with few options for alternative metering, net metering is a reasonable approach to provide value to the customer and the utility. As DG penetration increases, this assumption becomes less valid. There are external benefits associated with the development of DG. Solar PV displaces carbon-emitting sources. It can also reduce congestion on distribution lines, although it can also increase congestion—the net effect being location- and configuration-specific.

[al] Virtual net metering calculates a share of net metering for all participants in a group; it is usually administered through a subscription program, where consumers can easily withdraw from the program.

DG hosts receive the retail rate for exported electricity, leading to concerns by some that net metered customers avoid paying the full ongoing costs of providing and maintaining distribution-system infrastructure, as well as the costs of providing power when the distributed generators are not generating (as at night with solar).[248] Moreover, because volumetric rates as designed are generally not a true representation of the utility's variable costs (they typically include a substantial portion of the utility's fixed costs, as well), net metered customers who reduce the volumetric portion of their bill will likely pay a lower amount toward the utility's fixed costs. Efficiency measures can have similar effects. This can lead to revenue shifts from low-demand and net metered consumers to others depending on location and configuration.[249] Contentious discussions around the results of net metering include whether rates structured in this manner can contribute to inadequate valuation of grid services, revenue shifts, and cost shifts for maintaining the grid from DG participants to or from non-participants. These shifts can be significant, with a recent study performed for the CPUC forecasting that the cost shift associated with net metering would be $1.1 billion per year by 2020.[250]

If, as the evidence suggests, net metered customers are in some cases covering their costs while creating a revenue shift to other customers, rates may need to be better aligned with costs and benefits across the system. Some studies have suggested that the presence of revenue shifts does not necessarily imply that net metered customers do not fully compensate for the utility's cost of serving them. Studies of net metering in Nevada and California suggest that a number of classes of net metered customers have been paying more than it costs to serve them.[am, 251, 252] In contrast, a study performed for the Louisiana Public Service Commission concluded that net metered customers do not cover their cost of service.[253]

In some instances, the benefits of distributed solar may exceed the retail rate from net metering programs and result in a shift of benefits from net metered customers to other households.[254] Many studies have also attempted to quantify not just how DG adds costs to the electricity system but how distributed PV increases social benefits by reducing GHG emissions, air pollution, exposure to fuel price volatility, and the need for electricity generation at times of peak load.[an, 255] Depending on the method used and the current generation technologies considered, the environmental benefits have been estimated at more than 10 cents per kWh and the fuel price risk reduction at a similar value.[256] By including environmental benefits, several states have found that the total value of distributed PV exceeds the retail rate.[257] Many of these costs and benefits are "externalities" that are now not typically part of utility consideration. However, it should be noted these environmental and system benefits accrue equally from both distributed PV and utility-scale solar generation; but, in general, utility-scale solar generation is not eligible for net-metering-like compensation structures.[ao]

Considering the complexity of evaluating distributed energy investments, some state regulators are reevaluating compensation models for utilities. They are exploring innovative ways to value the costs and benefits of DER to the grid and improve market mechanisms that align investments, behavior, and operations. Net metering only compensates for energy services without provisions for payments for grid services such as volt/var (volt-ampere reactive) support and other ancillary services. New compensation arrangements could incent customers to provide these services, but without new payment arrangements, customers are disincentivized to provide grid services that may reduce the amount of energy exported to the grid. As of October 2015, 25 states are reviewing their net metering policies.[258] Table 2-2 lists some alternatives to net metering under consideration. Early movers will serve as test beds to guide other states considering alternatives. As this happens, however, consumers who have already invested in distributed PV may face

[am] The CPUC study found that in 2011 non-residential net metered customers (56 percent of net metered systems) paid 112 percent of the cost to serve them, while residential net metered customers paid 81 percent of the cost to serve them.

[an] Generation at times of peak load is particularly valuable when there is little solar installed; this value declines for subsequent installations.

[ao] Additionally, total system costs for utility-scale solar generation are lower than for an equivalent capacity of distributed PV due to economies of scale.

substantial economic loss if they are not grandfathered and receive substantially reduced rates for the electricity they provide to the grid. Regulatory uncertainty can also make it more difficult to secure financing and can drive up the cost of capital for DG. Educating and informing residential and small commercial consumers about potential regulatory risks associated with DER investments should be a priority. As technology and markets evolve, states can build their capacity to value DG, distributed storage, DR, and energy efficiency, and to effectively include them in resource planning.

Table 2-2. Alternative Rate Options for Distributed Solar

Structure	Description	Utility Example
Value of Solar	Utilities and other stakeholders attempt to calculate the full social value of distributed PV, including its environmental benefits, and use that to develop a tariff for all electricity exported to the grid from a distributed PV facility.	Austin Energy; Minnesota's statewide value of solar tariff has not yet been implemented.
Net Billing	Distributed PV host receives neither credit nor charge for electricity consumed onsite but receives compensation for exported power at an administratively determined rate, often set at the cost of procuring utility-scale solar power.	Imperial Irrigation District
Self Supply and Grid Supply	Consumers choose to supply all of their own power, in which case they are excused from some charges but not compensated for any exported electricity. Or, they must buy all of their power at retail rates and sell all of their onsite generation at a lower rate.	Hawaiian Electric Company
Increased Fixed Charges	Net energy metering is maintained, but its value and any associated cost changes from infrastructure upgrades (not counting externalities) are reduced by increasing fixed charges and decreasing volumetric charges.	Wisconsin Utilities

The increasing penetration of rooftop solar and advanced metering is driving and enabling regulatory changes. Regulators and utilities are considering alternative rate options for compensating customers for grid services while continuing to support new technology, maintain infrastructure, and ensure affordability for all customers.

Net metering is a first step in developing methods to compensate customers for the services and generation they provide to the grid. Some of the limitations of net metering may be addressed by creating separate rate classes for DG participants and incorporating elements of net metering into more sophisticated rate structures for that customer class. Moving forward, states and utilities will likely look to use more robust valuation methods. Accordingly, new rate structures and consumer-compensation policies for some consumers—more precise tools than current net metering policies—will enable efficient compensation for a wider array of distributed resources. The group of technologies eligible for compensation may likely grow to include more flexible convertors, DES, load-controlled hot water heaters, and other smart grid-controlled devices that could provide ancillary and load-shifting services. When redesigning rates that enable customers to pursue options that provide them and the utility value-based options, recovering the cost of providing distribution services is of critical importance. As such, an issue is the proper identification and valuation of the costs and the benefits provided by the growing array of customer options.

Consumers who want to maintain their existing service options sometimes get lost in the process. These consumers pose considerations for relevant regulators and marketplace operators. The implementation of new technologies and services present opportunities for enhanced flexibility to help meet consumer expectations.

However, in achieving this increased flexibility, regulators and market operators should actively minimize negative impacts on non-participating consumers, though public policy objectives may expand the scope of impacts considered. Net metering is the most common rate for distributed PV, but many utilities are exploring alternative structures.

Providing Incentives through Ratemaking

Cost-of-service ratemaking creates unique incentives for the utility. Regulation can be a substitute for competitive market pressures; it creates a variety of incentives, driven by the unique treatment of different cost elements, in the determination of rates.

As noted, the rate-making process determines how much a utility can earn, based on the two primary factors: (1) the allowed return on capital, and (2) the utility rate base. Utilities earn profit from a return on capital. Thus, if it costs a utility less to raise money than it earns on its investment, it will have an incentive to over-invest. A reverse bias is created if the cost of capital is set too low or regulation creates obstacles to fully recover capital; for example, promoting energy efficiency without a fixed-cost recovery true-up, a mechanism by which a utility evaluates over-recovery and under-recovery of revenues and either returns funds or levies charges to customers.

Regulatory incentives will play an important role in the enthusiasm with which utilities pursue different activities and the relationships between utilities and third-party providers pursue. For example, to encourage utility participation in energy efficiency programs, regulatory commissions have used three approaches:

1. Cost recovery for energy efficiency expenses
2. Compensation for lost margins associated with lower energy sales
3. Incentives, such as share–the-savings approaches, to motivate utilities to pursue energy efficiency.

The industry is now facing an analogous situation with DER, for example, where net metering is viewed as a mechanism by which utilities would lose revenues. It is one of the factors that complicates the ability of utilities to provide customers the services that unregulated competitors can also provide. The structure of new business models will create incentives that guide utility operation and investment decisions in the future. In the process of developing this new regime, it is important to provide incentives for utilities to both pursue and enable non-utility service providers to meet national goals of a secure, reliable, and affordable electricity system.

Providing Resources to Inform Rate Design

Regulators must design rate structures that support electricity service to customers, incent desired policy outcomes, allow for a fair return on investment, and maintain affordable electricity for the consumer. Regulators find themselves in a new environment characterized by rapidly changing technologies, vast amounts of data being produced throughout the system, and a suite of new stakeholders participating in rate cases. An important Federal role may be to facilitate best analytic practices related to ratemaking and to ensure full transparency to costing exercises in both IOU-regulation forums and public entity forums. Information is a growing key factor in all aspects of electricity service, from power plant management to customer interfaces, and customer-side-of-the-meter devices and applications. The importance of information makes it a key valuation factor, as well. The right information applied in the right way can have significant value-enhancing effects. For instance, information essentially creates value in the following ways:

- Increasing transparency and identifying new opportunities with high potential rewards improve economic profitability by recognizing risks and thereby reducing the cost of capital.

- Reducing uncertainty, such as lowering initial costs, maintaining a lower life-cycle cost, reducing the perception of risks by increasing the control of risks, or reducing constraints—barriers that limit growth, innovation, and improved performance.
- Exploiting the relative advantage of having superior information, such as saving time and effort, or reducing lag times, or increasing the scale and immediacy of rewards.

DOE has begun a process of evaluating the costs and benefits of DER, providing a taxonomy of costs, and framing the disputes associated with valuation of each cost element.[259] The costs and benefits of many smart grid applications were also captured through the Smart Grid Investment Grant Program and Smart Grid Demonstration Program of the American Recovery and Reinvestment Act of 2009.[260] In addition, a consortium of National Labs, the Tennessee Valley Authority, the National Association of Regulatory Utility Commissioners, and planning collaborations in the Eastern Interconnect is developing a grid-services and technologies-valuation framework under the DOE Grid Modernization Lab Consortium.[261] As part of its integrated grid effort, Electric Power Research Institute is developing a benefit-cost framework for quantifying the impact of DER on the distribution and bulk power systems. Importantly, sharing information nationally on valuation of costs and methods of developing rates does not imply a nationally prescribed method of determining costs and rates; such determination is a state responsibility.

There has been a great deal of innovation in the role of the customer, rate design, and technologies used to provide service to customers. Cost drivers are shifting, new costs are being considered, and the importance of rate design has increased—both for engendering customer response and as a method of encouraging component and system efficiency and DER. The National Association of Regulatory Utility Commissioners has framed many of the issues that need further exploration in its recently released rate-design manual.[262] Given the importance of rates—not only for compensating utilities, but, increasingly, as a vehicle for providing price signals to customers who provide transactive load and DER—it would be very valuable for the Federal Government to facilitate a national review of retail rates and the creation of a national repository of rate information.

Adapting the Distribution Utility Business Model

The electric distribution utility now faces a fundamental transformation. The emergent role of the consumer as prosumer and new imperatives, such as resilience, a cleaner energy future, and grid security, are driving the current evolution. Additional investments to support enhanced services are required, including the new transactive role for customers and the higher levels of flexibility and reliability that will support the digital economy.

It is important to understand that alternative utility business models and regulatory practices are inextricably linked. Modification of the traditional ratemaking-based utility business model must be acceptable to state regulators, responsive to customers, financially tenable to utility shareholders—all while supporting innovation (whether by the utility or third-party providers). The business model is part of a triad of interrelated elements, which includes the regulatory structure and economic/market structure that determine the nature of customer service.[263]

Many people have proposed models that represent potential evolutions of the distribution utility, including one that represents endpoints on a spectrum between two models: the Smart Integrator and the Energy Services Utility.[6] The Smart Integrator is described as an operator of the distribution grid in much the same way that an ISO operates the transmission grid and wholesale power markets. It is a platform for transactions, but it does not participate in energy transactions. The Energy Services Utility shares the basic functions of the

Smart Integrator, but it is also a provider of services. It is an extension of the vertically integrated utility. Two questions will determine how the utility business model evolves:

1. What services can (and should) the distribution utilities provide now and in the future?
2. How should utility rates be designed to provide price signals to customers and to compensate utilities for the services they render, including incentives to provide both traditional and nontraditional services?

At issue is the nature of the entities that provide services at the customers' premises, the terms of compensation, and the effect on the ability of utilities to recover the cost of acting as the conduit to the grid.

Models for Provision of Demand-Side Services

There are alternative vehicles for delivering services to customers. An essential question in drawing the future scope of the utilities is whether they will provide energy efficiency services and under what terms. The answer will also play a large role in determining the business models of competitive providers. There are four basic approaches to the provision of energy efficiency:[ap]

1. Programs derived from the utility's planning process (e.g., integrated resource planning to determine the level of cost-effective energy efficiency) and administered by the utility
2. Programs derived from the utility's planning process (e.g., integrated resource planning to determine the level of cost-effective energy efficiency) and administered by a third party operating under a state or utility program
3. A market-based approach, in which third-party providers seek profit by selling energy efficiency services to customers
4. A market-based approach, in which individual customers act in response to electricity price signals.

In the first two approaches, the utility collects funds for programs through customers' bills. Customers directly finance the last two approaches above. Interacting with the four approaches to the provision of energy efficiency listed above, several business models are possible depending on the particular approach that a utility and its regulator take (Table 2-3).

[ap] Energy efficiency standards have played a vital role in transforming the efficiency of available products. This section is concerned with the choice and acquisition of those products.

Table 2-3. Energy Efficiency Business Models[265, 266]

Utility Programs	Utility energy efficiency programs are part of a resource-acquisition process in which a utility plans for resources that it expects to need in order to provide reliable service.
Independent Entities	Some states use independent entities to administer energy efficiency programs. Their purpose is to invest in services and programs that save money and conserve energy. The fee is based on integrated resource plans that consider both environmental and economic costs.
State Agency Administered	Some states, such as New York, employ a blended approach, whereby some the New York State Energy Research and Development Authority implements the efficiency programs, and the utilites implement others.
Market-Based Providers	Some non-utility companies provide value by serving as the interface between customers and the market (e.g., Comverge).
Energy Service Companies	Energy service companies (ESCOs) offer both private provision of energy efficiency services and a vehicle for implementation. They typically use performance contracts in which the ESCO guarantees energy and/or dollar savings for the project, linking ESCO compensation to the performance of the project.

An array of actors in the electricity sector including utilities, private-sector companies, and state agencies offer energy efficiency programs. Energy efficiency programs are available both in wholesale electricity market areas and within regulated vertically integrated utility areas.

Models for Integrating Distributed Generation

DG delivers power into the distribution grid near the load center. Typically, DG is on the customer side of the meter: the customer installs generation, storage, or a controllable load and ties into the grid via the distribution utility. Utilities can integrate DG using a variety of business models (Table 2-4). These models could be on the customer side, where utilities sell DG products directly to the consumer or on the utility-side, where DG providers sell energy directly to the utility. Although as DG provides more electricity, the generation and management of electricity may become a shared responsibility among utilities, customer-owned DG, and other DG-service providers.

Today, most DG installations occur on the customer side of the meter.[267] Except in rare cases, the customer remains connected to the distribution grid, which serves any load unmet by the DG. When the DG system produces power in excess of customer needs, that power may be sold into the distribution system. The majority of this DG is on the customer side, with very few customers selling power back to the grid. Sales to the interconnected utility could occur under a net metering arrangement, a value of solar tariff, a feed-in tariff,[aq] a Public Utility Regulatory Policies Act contract, or as a negotiated wholesale sale.

[aq] Feed-in tariffs are set prices paid by utilities to customers for production of renewable energy.

Table 2-4. Business Models for Distributed Generation

Customer Ownership	The customer finances the installation, keeps any renewable energy credits associated with solar production, enjoys the tax benefits of the investment, and keeps the bill credit from net metering (or revenue stream from an alternative compensation scheme, such as a value-of-solar or feed-in-tariff).
Power Purchase Agreements	PPAs are standard contract vehicles for long-term power purchases from a third-party developer.
Utility Affiliate Model	The utility invests capital in developing DER through an affiliate. Codes of conduct bar affiliates from competing in markets in which their parent (franchised) utilities do business, or subject affiliates to special restrictions and oversight.
Utility Provided Customer-Premises Model	Where allowed, utilities may offer DER systems to customers and, like other utility generation investments, include the capital cost in the rate base. The utility (as opposed to an affiliate) is the supplier.
Aggregators	Aggregators are companies that group customer load or generation assets together to facilitate their participation in the markets.
Utility-Owned DER	Utility-owned DER can be located either on a customer's premises or on utility property.
Utility-Provided DER	Utility-provided DER is, essentially, small-scale, utility-owned generation. This model alleviates the issue of high, upfront and installation costs that leave customers unable to participate.
Third-Party Merchant Model	Independent third parties can connect DER directly to the distribution system with no onsite customer involvement.

Utilities can integrate DG using a variety of business models to accommodate varying local and regional circumstances, market and infrastructure topologies, and consumer preferences.

Limitations on the Scope of Utility Activities

The scope of utility services defines the lines of business that it can pursue. There are two fundamental reasons for limiting scope. The first is to effectively prevent cross-subsidization of utility affiliate activities, in which ratepayers subsidize non-core utility activities. FERC and state PUCs largely formalized regulatory authorities to prevent cross-subsidizations. The second reason to limit utility activity, which is most important in framing the future distribution utility model, is to preserve consumer benefits of competition by enabling competitive power and services providers to effectively participate in the market. The latter rationale is important for determining which activities utilities are allowed to pursue.

Utility restructuring greatly altered the electric utility business model in some states by breaking up vertically integrated utilities and introducing competition and customer choice.[268] Utilities' divestiture of generation allayed concerns about anti-competitive behavior, such as cross-subsidies between affiliates and favored treatment of affiliates in the new market.

PUCs in restructured states frequently encouraged or required divestiture of generating assets so that the utilities no longer controlled their own generation. As was the case in New York, the primary rationale for divestiture was to break the economic ties between electricity distribution, transmission, and generation services to create a competitive wholesale electricity market. Between 1998 and 2001, utilities divested more than 300 electric-generating plants in the United States, nearly 20 percent of total generating capacity.[269] In 1997, only 1.6 percent of U.S. electricity was produced by non-utility generation, rising to 25 percent by 2002 and nearly 35 percent in 2012.[270]

Ultimately, the question is not what the utility affiliate is permitted to do, but which functions the utility itself is allowed to perform. Some basic questions should be addressed in the process of determining the scope of utility activities:

- Does prohibiting utility activity mean giving up economies of scale and scope?
- Which option provides customers with the lowest cost of service?
- How can the utility expand consumer choice?

California's policy is a hybrid approach, allowing net metering with third-party development through PPAs and utility investment in PV. State IOUs are allowed to own and operate solar PV facilities and execute solar PV PPAs with independent power producers through a competitive solicitation process.[271] California has also pursued a hybrid approach to utility/market provision. This approach promotes storage technology that enhances grid optimization, the integration of renewable energy, and the reduction of GHG emissions, and explicitly provides a role for the utility. Under California State Law Assembly Bill 2514, the CPUC is required to establish procurement targets for the state's three IOUs to acquire viable and cost-effective storage. In October 2013, the CPUC established procurement targets that required the three IOUs to procure 1,325 MW of storage by 2020, with targets divided among three industry segments: transmission-connected, distribution-level, and customer-side-of–the-meter applications. In contrast with the state's policy on rooftop solar installations, utilities are allowed to own up to 50 percent of their cumulative targets.[272] The State of New York's Reforming the Energy Vision initiative is also seeking to reform the utility business model. The New York Public Service Commission in 2014 issued a proposal that would establish the utility as a distribution system platform (DSP) provider. The proposal is divided into two tracks. Track 1 addressed the development of DER with the utility as DSP providers, and Track 2 addresses reform of utility ratemaking and revenue streams to adapt to the DSP model.

Nature of Consumer Protection Changing with New Players

The nature of consumer protection is changing. Historically, the regulatory structure was established to oversee the relationship between the utility and consumers, and PUCs have the authority and obligation to protect consumers through the administration of the regulatory compact. PUCs assure reasonable prices and act as an arbiter of consumer complaints. Consumers can acquire electricity from on-premise DG, either through direct purchase or long-term transactions with third-party providers where permitted. Non-utility entities can also provide other energy services, like energy efficiency retrofits. These third-party providers create new relationships with the consumer that the regulatory compact did not envision. The relationship between the consumer and these non-utility entities are usually governed by contract law. In cases where such contractual relationships include fraudulent conduct, the Federal Trade Commission and state attorneys general—not PUCs—have oversight authority.

When customers decide to develop solar resources on their premises, they must make two important decisions. These include (1) whether to buy, lease, or enter into a PPA and (2) the size of the solar facility. Typical customers tie these decisions to the property they occupy, and they may not have adequate information about risks and impacts since that information primarily comes from the vendors who want to either sell or enter into long-term contracts.[273, 274]

There are two types of long-term contracts: (1) a customer signs a traditional lease and pays to use a solar system, or (2) a customer signs a PPA and pays a set monthly rate for the electricity that is generated. The lengths of the contracts are typically 20–30 years (although some are shorter) and contain the provision that any excess power produced will be sold to the grid at the retail rate (net metering). By 2014, 72 percent of the residential solar in the United States was sold under solar leases and PPAs.[275, 276] Different states have different policies on third-party financing. As of March 2016, 25 states, plus the District of Columbia and Puerto Rico allowed third-party solar

PPAs; 8 states prohibited third-party solar PPAs; and the legal status was unclear in 16 states.[277] The Solar Energy Industries Association published the Solar Business Code and best practices for consumer protection in 2015, by which member companies must abide.[278]

Retail open access allows customers to shop for electricity from competitive, alternative providers. Electricity is not a typical good that lends itself to comparison shopping, given that there are different terms that affect the ultimate delivered price of electricity. As a consequence, low-income and vulnerable populations are particularly susceptible to unscrupulous behavior. The staff of the New York Public Service Commission recently found that since 2014 residential customers paid alternative energy suppliers $817 million more than if they had remained with their utility for gas and electric supply.[279, 280, 281] The New York Public Service Commission is now re-exploring its role in monitoring and protecting consumers who purchase power from alternative providers.

The transformation of the electric markets has focused on competition and the offering of new service options to customers—largely by non-utility providers. This focus has increased innovation, but it has also made the role of customer protection more ambiguous, creating the need to develop mechanisms to increase transparency. Part of the transformation requires new tools for monitoring third-party interactions with customers—from fraudulent claims to failure to meet contractual obligations. State PUCs may require new powers to fulfill their historic role of protecting customers.

Federal and State Jurisdictional Issues

Rapid changes in the electricity sector raise questions about who should regulate new services and market entrants and the growth of long-distance transmission across state and RTO boundaries. There is increased potential for tensions between existing regulatory bodies at the state and Federal levels, and the Federal Power Act's (FPA's) bright line delineating Federal and state jurisdiction authorities is increasingly blurred. Certain new technologies, such as DG, sophisticated load controls that facilitate demand management, microgrids, and storage, are not as clearly delineated as being solely within the realm of wholesale or retail jurisdiction. These technologies have different attributes than the electricity technologies that existed when the FPA was enacted, and they are capable of providing multiple services across the traditional generation, transmission, and distribution boundaries.

Growth in Distributed Generation Raise Jurisdictional Questions

Over the past 15 years, FERC has issued a series of orders largely disclaiming jurisdiction from resources participating in net metering programs. FERC's interpretations of its jurisdiction essentially allow state net metering programs to continue without triggering Federal regulatory applicability that could stymie state initiatives. These decisions rest on a regulatory construct that consumers with onsite generation are "offsetting" consumption and thus are not engaged in making wholesale sales regulated under the FPA.

The overall system impact of DG is also increasing as its deployment expands. More often, DG is being combined with other technologies such as onsite storage, DR, and enhanced technical controls, and it is being used to serve wholesale capacity, energy, and ancillary services markets through aggregation. If the distributed generators providing these resources are still connected close to load and within the state-regulated distribution system, then coordination between the wholesale and retail markets and Federal and state regulators will be necessary to avoid and resolve conflicts.

One application of DG is for microgrids, which raises new jurisdictional issues. In areas where a single electricity provider is granted a monopoly franchise, regulations may prohibit any other entity from constructing new electricity-related infrastructure or providing electricity to end users.[282, 283] Other regulatory issues may arise in the case where a microgrid operator purchases electricity from owners of distributed resources in their system and resells that electricity to other users within the microgrid. The FPA could consider such a transaction as a sale for resale, which Federal law prohibits.[284] Despite lingering regulatory and jurisdictional uncertainties, the number and diversity of microgrids continue to grow.[285]

Demand Response and Wholesale Energy Markets

In 2008,[286] FERC issued Order No. 719 to, among other objectives, ensure the comparable treatment of DR to other resources in organized markets and to permit DR aggregators to participate in markets on behalf of retail customers.[287] However, with this order, states can also opt out of FERC's DR policy and foreclose DR participation in markets.

FERC issued FERC Order No. 745 in 2011, requiring that DR resources receive compensation for the services they provide to the energy market at the locational market price for energy.[288] FERC experienced pushback from utility and generator competitors to DR, but the Supreme Court ultimately upheld the order in *Elec. Power Supply Ass'n v. FERC*. The Court found that Order No. 745 did not directly regulate retail electricity sales and thus was within FERC's jurisdiction. The ability of end-use customers to offer DR commitments in the wholesale market, and to receive compensation for those commitments, is made possible by technology changes that allow those customers to be aggregated, monitored, and metered. Thus, the participation of end users (to whom sales are clearly within state jurisdiction) in wholesale energy markets, which were subject to FERC oversight, ultimately presented a rationale for regulation under the FPA jurisdictional provisions.

Electricity Storage: Multiple Services Complicate Jurisdictional Issues

Electricity storage capabilities include any facility that can receive electric energy from the grid and store it for later injection of electricity back to the grid.[289] A variety of technologies fit into that category including batteries (grid scale or those in EVs), flywheels, compressed air, and pumped hydro. These technologies vary in capacity and may be connected directly to the transmission grid, a distribution system, or behind-a-customer meter. Energy storage is unique because it can take energy or power from the grid, add energy or power to the grid, and supply a range of grid services on short (subsecond) and longer (hours) time scales. In certain cases, a single storage resource or an aggregation of storage resources can provide multiple services simultaneously, such as frequency response or other ancillary services, dispatchable output akin to generation, or dispatchable load reduction somewhat like DR.

State-jurisdictional retail rates for some utilities include demand charges for industrial and commercial residential customers. Battery storage is expected to become an economical means to manage customer demand charges as system prices drop and the value of flexibility increases with a changing resource mix.[290]

However, deploying storage resources solely using the existing regulatory classifications (wholesale energy and ancillary services markets, transmission, and distribution) can limit the available "use cases." It can also constrain the services that a particular storage resource can provide and the revenue sources that owners or operators can obtain. One particular regulatory complication is that storage may be selling multiple services, some of which are subject to market-based prices and others that are sold at cost-based rates. The ability to "stack" these services to achieve sufficient revenues may require action from both FERC and state regulators.[291] State regulators and FERC recognize these regulatory constructs, and FERC is currently exploring the barriers to full participation of storage in organized markets. FERC recently issued a notice of proposed rulemaking to address electricity storage participation in markets operated by RTOs and ISOs.[292]

Potential Tools to Coordinate across Jurisdictions and Align Regulatory Approaches to Emerging Energy Technologies

In many policy areas, FERC has tread softly where it might have a claim of jurisdiction but did not want to preempt state regulation; in these instances, it has chosen to exercise its jurisdiction in line with state policy goals. Several tools are at FERC's disposal to deal with future potential jurisdiction challenges, impacting new and emerging technologies and the integration of markets for those technologies.

One way forward is through new frameworks that, for example, could establish rate-setting models that consider revenues from both state and Federal jurisdictions simultaneously. These models would allow resource owners to "stack" revenues from services they provide across state and Federal jurisdictions. It would also guard against the potential for over-recovery and unjust and unreasonable rates. In addition, FERC could explore including costs of additional technologies in rate design.

While rarely used, FERC has authority to establish joint hearings that would permit FERC and the states to hear cases together, but without a joint decisional procedure.[293] FERC can also delegate certain roles to "joint boards" made up of state commissioners (with no Federal representation).[294] More generally, FERC and state commissions can collaborate on policy matters of common interest.

Another possible approach is to redraw the line between Federal and state jurisdictions to better accommodate today's regulatory needs. In particular, this redraw should reflect the broader regional nature of electricity markets and the ability of new and emerging technologies to provide service across both Federal and state jurisdictional lines.[ar]

Another option would be to authorize jurisdictional agreements, which would permit a consensual resolution of potential conflicts between state agencies and FERC. Under this option, an amendment to the FPA would include provisions similar to those in several other Federal statutes[as] authorizing FERC and state commissions to enter into agreements that rationalize their respective state and Federal regulatory jurisdiction. The recommendations based on the analysis in this chapter are covered in Chapter VII (*A 21st-Century Electricity System: Conclusions and Recommendations*).

[ar] See e.g., National Labor Relations Act of 1935, Pub. L. No. 74-198, §§ 10(a), 14(c), 49 Stat. 449, 453, 457 (codified as amended at 29 U.S.C. §§160(a), 164(c)); Atomic Energy Act of 1954, Pub. L. No. 83-703, § 244, 68 Stat. 919, 958-59 (codified as amended at 42 U.S.C. § 2021 (2005)); Clean Air Act § 111(c), Pub. L. No. 91-604, § 111(c), 84 Stat. 1676, 1684 (1970) (codified as amended at 42 U.S.C. § 7411(c) (1977)).

[as] See e.g., National Labor Relations Act of 1935, Pub. L. No. 74-198, §§ 10(a), 14(c), 49 Stat. 449, 453, 457 (codified as amended at 29 U.S.C. §§160(a), 164(c)); Atomic Energy Act of 1954, Pub. L. No. 83-703, § 244, 68 Stat. 919, 958-59 (codified as amended at 42 U.S.C. § 2021 (2005)); Clean Air Act § 111(c), Pub. L. No. 91-604, § 111(c), 84 Stat. 1676, 1684 (1970) (codified as amended at 42 U.S.C. § 7411(c) (1977)).

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Chapter III

BUILDING A CLEAN ELECTRICITY FUTURE

This chapter explores the essential elements of a clean electricity system and identifies the policy, market, and technology innovations needed to improve its environmental performance. The United States has made substantial progress in reducing the environmental impact of the electricity system, but much work remains. The chapter first explores the greenhouse gas emissions from the power sector and the availability of low- and zero-carbon electricity sources, including nuclear, natural gas, solar, wind, hydropower, biomass, and geothermal sources. The next sections detail the interaction between clean electricity systems and key options and features, such as energy efficiency, demand response, flexibility, and storage. The chapter also includes a discussion of how the interplay of technology, markets, and policy can lead to a cleaner electric system, and how a cleaner electric system can support economy-wide decarbonization through the further electrification of other end-use sectors.

FINDINGS IN BRIEF:
Building a Clean Electricity Future

- A clean electricity system reduces air and water pollution, lowers greenhouse gas (GHG) emissions, minimizes waste, and limits the impact to the ecosystem in areas such as water and land use.
- Deep decarbonization of the electricity system is essential for meeting climate goals; this has multiple economic benefits beyond those of environmental responsibility.
- The United States is the largest producer and consumer of environmental technologies. In 2015, the U.S. environmental technology and services industry employed 1.6 million people, had revenues of $320 billion, and exported goods and services worth $51 billion.
- Though the U.S. population and economy have grown, between 1970 and 2014, aggregate emissions of common air pollutants from the electric power sector dropped 74 percent, even as electricity generation grew by 167 percent.
- U.S. carbon dioxide (CO_2) emissions from the power sector have substantially declined. Between 2006 and 2014, 61 percent of the reductions in CO_2 intensity were attributed to switching from coal- to gas-fired power generation, and 39 percent were attributed to increases in zero-emissions generation.
- The increasing penetration of zero-carbon variable energy resources and deployment of clean distributed energy resources (including energy efficiency) are critical components of a U.S. decarbonization strategy.
- It is beneficial to a clean electricity system to have many options available, as many of the characteristics of clean electricity technologies complement each other.
- Currently, 29 states and Washington, D.C., have a renewable portfolio standard, and 23 states have active and binding energy efficiency resource standards for electricity. States that have actively created and implemented such electricity resource standards and other supporting regulatory policies have seen the greatest growth in renewables and efficiency.
- The integration of variable renewables increases the need for system flexibility as the grid transitions from controllable generation and variable load to more variable generation and the need and potential for controllable load. There are a number of flexibility options, such as demand response (DR), fast-ramping natural gas generation, and storage.
- Energy efficiency is a cost-effective component of a clean electricity sector. The average levelized cost of saved electricity from energy efficiency programs in the United States is estimated at $46 per megawatt-hour (MWh), versus the levelized cost of electricity for natural gas combined-cycle generation, with its sensitivity to fuel prices, at $52–$78/MWh.
- Electricity will likely play a significant role in the decarbonization of other sectors of the U.S. economy as electrification of transportation, heating, cooling, and industrial applications continues. In the context of the second installment of the Quadrennial Energy Review, electrification includes both direct use of electricity in end-use applications and indirect use, whereby electricity is used to make intermediate fuels such as hydrogen.
- Realizing GHG emissions reductions and other environmental improvements from the electricity system to achieve national goals will require additional policies combined with accelerating technology innovation.

FINDINGS IN BRIEF:
Building a Clean Electricity Future (continued)

- Improved understanding of the electricity system and its dynamics through enhancements in data, modeling, and analysis is needed to provide information to help meet clean objectives most cost effectively.
- Decades of Federal, state, and industry innovation investments have significantly contributed to recent cost reductions in renewable energy and energy efficiency technologies.
- Innovation in generation, distribution, efficiency, and DR technologies is essential to a low-carbon future. Innovation combined with supportive policies can provide the signal needed to accelerate deployment of clean energy technologies, providing a policy pull to complement technology push.
- Nuclear power currently provides 60 percent of U.S. zero-carbon electricity, but existing nuclear merchant plants are having difficulty competing in restructured electricity markets due to low natural gas prices and flat or declining electricity demand. Since 2013, 6 nuclear power reactors have shut down earlier than their licensed lifetime, and 10 others have announced plans to close in the next decade. In 2016, two states, Illinois and New York, put policies in place to incentivize the continued operation of existing nuclear plants, and these policies may prevent 6 of the 10 announced closures.
- Enhanced oil recovery operations in the United States are commercially demonstrated geologic storage and could provide a market pull for the deployment of carbon capture, utilization, and storage (CCUS).
- Federal laws currently limit the ability of regulated utilities to utilize Federal tax credits in the same manner as private and unregulated developers. Publicly owned clean energy projects cannot benefit from the clean energy tax credits because tax equity investors cannot partner directly with tax-exempt entities to monetize tax credits.
- Low-income and minority communities are disproportionately exposed to air quality and water quality issues associated with electric power generation. Compared to the U.S. population overall, there is a greater concentration of minorities living within a 3-mile radius of coal- and oil-fired power plants. In these same areas, the percentage of the population below the poverty line is also higher than the national average.
- Some energy technologies that reduce GHG emissions, such as CCUS, concentrated solar power, and geothermal generation, have the potential to increase energy's water intensity; others, such as wind and photovoltaic solar power, can lower it. Dry cooling can reduce water intensity but may increase overall GHG emissions by decreasing generation efficiency. Though there can be a strong link between energy and water efficiency in energy technologies, many research, development, demonstration, and deployment funding criteria do not incorporate water-use or water-performance metrics. Designing technologies and optimizing operations for improved water performance can have both energy and water benefits.
- There is currently no centralized permanent-disposal facility for used nuclear fuel in the United States, so this radioactive material is stored at reactor sites in 35 states awaiting development of consolidated storage facilities and/or geologic repositories.
- Coal combustion residuals, such as coal ash and scrubber slurry, are the second most abundant waste materials in the United States, after household waste.
- There is a range of decommissioning needs for different types of power generation facilities.

Building a Clean Electricity Future

A recent poll noted that "73% of voters support a national energy policy that ensures a secure supply of abundant, affordable, and available energy for the American people in an environmentally responsible manner."[1] The views of the respondents in this poll suggest that the American people do not view environmental and other goals to be in conflict; the United States has consistently been able to manage environmental pollution while also maintaining electric reliability, growing the economy, and supporting millions of jobs.

While electricity is the workhorse of our modern economy, it is also responsible for more than 30 percent of U.S. greenhouse gas (GHG) emissions.[2] Reducing GHG emissions is a key imperative for the power sector. When considering the scale of this challenge, it is important to recognize that the reduction of adverse public health and environmental impacts from electricity generation has been one of the major U.S. environmental success stories of the 20th century. Since 1970, emissions of common air pollutants from the electric power sector have decreased by more than half.[3] In the near term, carbon dioxide (CO_2) emissions from the energy sector fell by 10 percent from 2008 to 2015, while the economy grew by more than 10 percent over this same period.[4] This success is even more notable because it occurred in conjunction with increased electricity generation and significant, sustained economic growth.

Enabling a clean, flexible, reliable electricity system will require continuous cost reductions and improved environmental performance of energy technologies. There are multiple avenues for improving the environmental performance of the electricity system by building on past successes. A cleaner electricity generation system can be achieved through a combination of technological innovation and incentives, national environmental policy, innovative state policy, and financial mechanisms. These findings are supported by detailed modeling of scenarios for the electricity system, which demonstrates the role of innovation and effective policy in improving environmental outcomes. The chapter also examines approaches to further reducing the environmental impacts of electricity on air and water, as well as mitigating relevant land-use challenges and environmental justice issues affecting local communities.

There are, however, ongoing environmental impacts associated with electricity systems that merit sustained policy and regulatory focus and support. These include climate change; water use for power generation; land-use impacts of power generation, transmission, and distribution; environmental justice issues associated with electricity; and decommissioning of generation assets. Today, the United States has an opportunity to build on its substantial experience of joint environmental and economic success to address the central challenge of climate change mitigation, along with environmental challenges associated with electricity generation, distribution, transmission, and consumption.

CO_2 Emissions and the Electricity System

The growth in U.S. electricity consumption has gradually slowed from 9.8 percent per year in the 1950s to 0.5 percent per year over the past decade, due in part to "slowing population growth, market saturation of major electricity-using appliances, efficiency improvements in appliances, and a shift in the economy toward a larger share of consumption in less energy-intensive industries."[5, 6] In 2014, electricity accounted for 39 percent of total primary energy consumption.a The residential and commercial sectors each consumed about the same share of total electricity—37 percent and 36 percent, respectively—with the industrial sector accounting for 26 percent of electricity demand. Electricity use in the transportation sector was minimal, constituting less than

[a] 38.4 quadrillion British thermal units (quads) were used to generate 3,900 terawatt-hours (TWh) of electricity. Total energy consumption in 2014 was 98.3 quads.

1 percent of total U.S. electricity consumption.[7] Electricity use is projected to grow slowly, and its share of total delivered U.S. energy consumption is expected to increase only slightly by 2040.[b, c, 8]

Electric power generation is one of the largest sources of CO_2 emissions in the United States.[9] Over 99 percent of the GHG emissions attributed to the power sector are the result of the combustion of fossil fuels for power generation. In 2014, CO_2 from coal combustion accounted for over three-quarters of U.S. power sector GHG emissions, while CO_2 from the combustion of natural gas contributed approximately 21 percent of U.S. power sector GHG emissions.[10, 11] The emission rate—the amount of CO_2 emitted per unit of electricity generated—is a key indicator of the climate impact of electricity generation and varies significantly by fuel and technology. The current average emission rate of natural gas combined-cycle (NGCC) plants in the United States is 60 percent less than that of average coal-fired plants.[12, 13] Nuclear power and renewable electricity generation have no direct emissions associated with electricity generation.

Electric power generation provides service to end-use economic sectors. When attributing current U.S. power sector GHG emissions to end-use economic sectors, the industrial sector is responsible for approximately 26 percent of electricity-related emissions, and the remainder is split evenly between the residential and commercial sectors, at 36 percent and 35 percent, respectively.[d, 14] This sectoral attribution highlights a dual pathway for reducing total carbon emissions: (1) decarbonization of the electricity sector itself and (2) electricity efficiency improvements within end-use economic sectors.

Decarbonization of the Electricity System

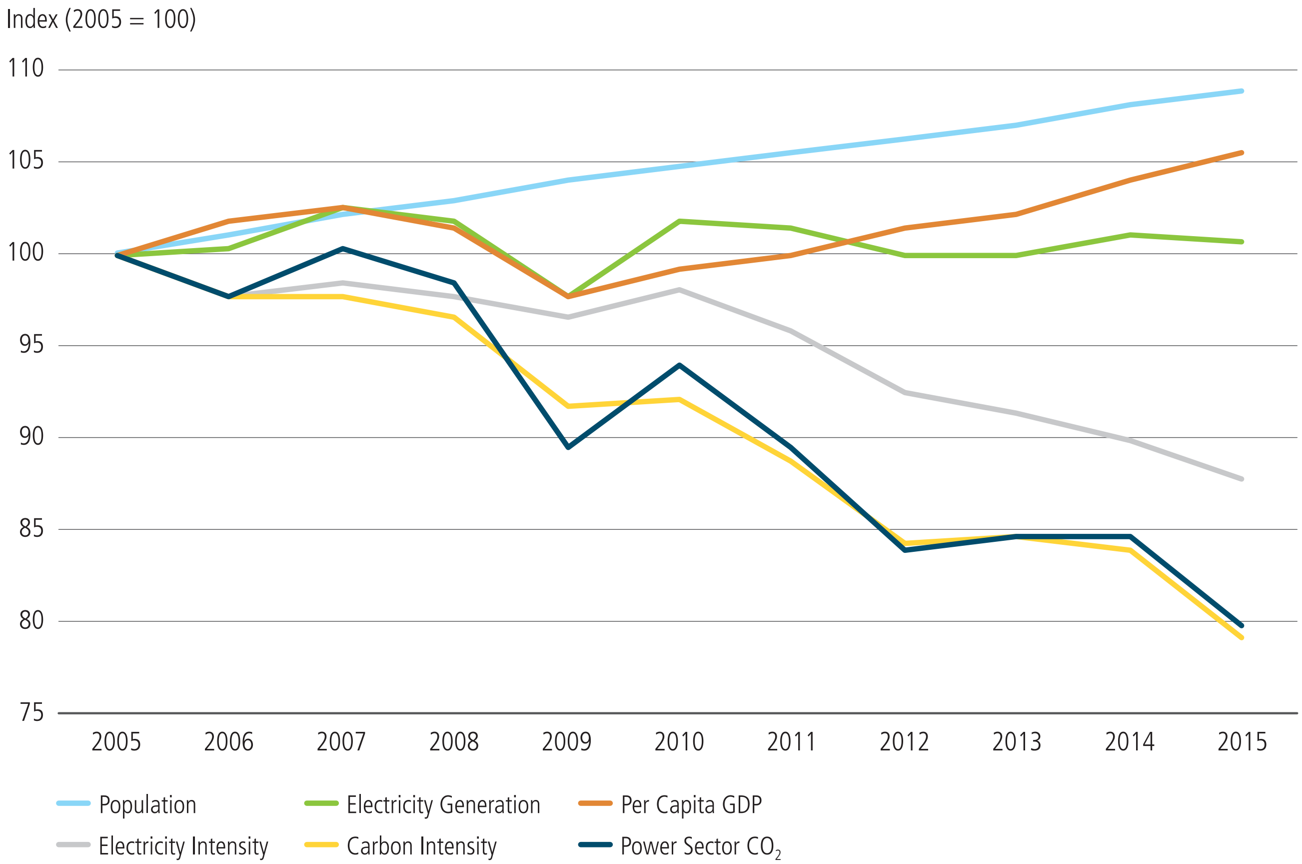
After a gradual decline from 1970 to 2005, in 2015, the CO_2 emission rate (kilograms of CO_2 per megawatt-hour [MWh]) of electricity generation fell to 20.9 percent below 2005 levels.[15]

[b] According to the Office of Energy Policy and Systems Analysis (EPSA) Base Case, which incorporates all existing U.S. policies but assumes no new policies, electricity use is projected to grow at an annual rate of 0.65 percent between 2014 and 2040. In terms of delivered energy, the electricity sector's share is projected to increase from 18 percent in 2014 to 19 percent in 2040, and overall electricity demand is projected to increase from 12.76 to approximately 15 quads.

[c] In terms of total primary (or source) energy, the electricity sector's share is projected to increase from 13 percent in 2014 to 14 percent in 2040, according to the EPSA Base Case, which incorporates all existing U.S. policies but assumes no new policies.

[d] The remaining electricity-related emissions are from other sectors that account for minor amounts of electricity-related emissions in the United States, including agriculture (3 percent) and transportation (0.2 percent).

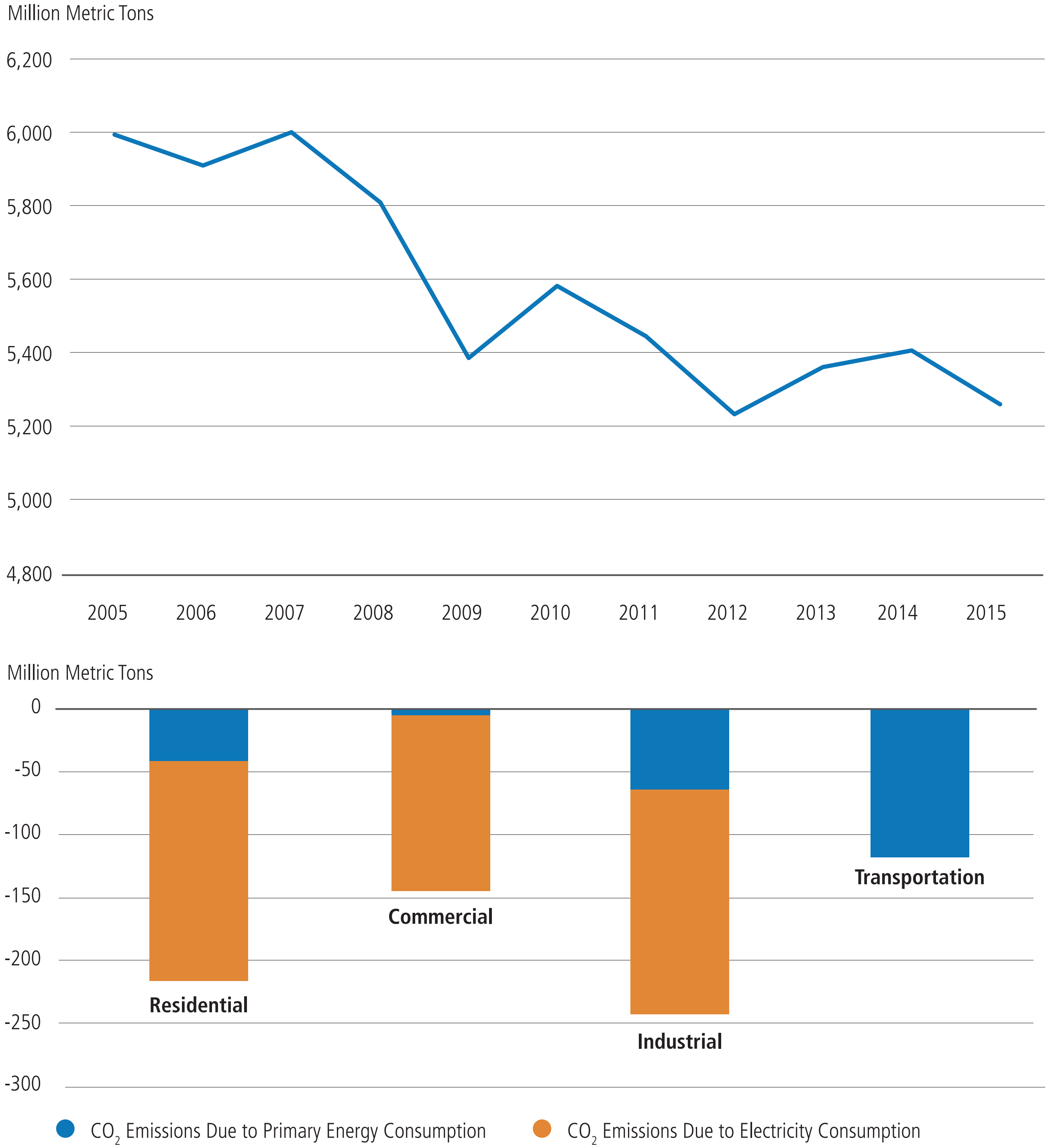
Figure 3-1. Recent Trends in CO_2 Emissions Drivers, 2005–2015[16, 17, 18]



The population growth, per capita gross domestic product (GDP), and electricity intensity of the economy all factor into total U.S. electricity demand. While growth in population and per capita GDP has placed upward pressure on power sector demand, this growth has been partially offset by a decline in the electricity intensity of the economy.

Slow growth in per capita electricity consumption, greater electricity productivity (measured in dollars of gross domestic product [GDP] per kilowatt-hour [kWh] of electricity), and a decline in the CO_2 emission rate from electricity generation have already helped decouple economic growth from electricity consumption (and, consequently, electricity generation–related CO_2 emissions).[19] U.S. power sector CO_2 emissions have declined even while the population and the economy have grown. As shown in Figure 3-1, between 2005 and 2015, the U.S. GDP grew by 14.8 percent, and the amount of electricity consumed per dollar of GDP declined by 12 percent due to greater economic productivity per kWh of electricity consumed. As shown in Figure 3-2, energy-related CO_2 emissions reductions in recent history have occurred in the electric power sector, largely because of the decreased use of coal and the increased use of natural gas for electricity generation.

Figure 3-2. U.S. Energy-Related CO_2 Emissions, 2005–2015 (top), and Change in U.S. Energy-Related CO_2 Emissions by Sector, 2005–2015 (bottom)[20, 21]



After increasing in 2013 and in 2014, energy-related CO_2 emissions fell in 2015. In 2015, U.S. energy-related CO_2 emissions were 12 percent below the 2005 levels, mostly because of changes in the electric power sector.

In addition to these market and technology trends, a wide array of policies and measures developed and implemented at the Federal, state, and local levels have helped to mitigate GHG emissions from the U.S. power sector. These include performance-based regulations and standards, economic instruments, information programs, and diffusion of key technologies from robust research, development, and demonstration (RD&D) investments. Many policy approaches cross these categories. Federal and state emissions trading programs, for example, combine performance-based regulation with trading of marketable credits or allowances, the latter of which are economic instruments.

Upgrading and investing in the transmission system is one critical measure that could have far-reaching impacts for the environment, could increase system flexibility and resilience, and could save electricity consumers as much as $47 billion annually.[22] A modernized and expanded transmission system has the potential to interconnect clean generation (for both connecting over short distances and connecting remote clean generation sources to population centers) while also enhancing a national electricity market in which all energy assets can fairly compete. State clean electricity goals are also facilitated through transmission upgrades; one example is the New York Independent System Operator (ISO), which is looking to make more effective use of rurally located wind and hydropower resources by connecting them with high electricity demand centers like New York City.[23]

It can be challenging to evaluate whether transmission policies and regulations are simultaneously (1) achieving their intended reliability benefits in the face of unprecedented physical change and (2) providing adequate capacity to cost-effectively address environmental requirements. Such evaluation requires new analyses, but for those analyses to be valid, data with greater scope, frequency, and resolution must be made available. Expanded transmission data resources will facilitate the development of effective Federal and state policies and regulations that will affect reliability and environmental goals, give those that invest in the transmission system insights into potential business opportunities, and provide a broad range of stakeholders with a greater understanding of the fairness of operations in providing non-discriminatory access. The Federal Energy Regulatory Commission (FERC) has recognized the importance of electricity transmission in a clean energy future and has worked to expedite the contribution of transmission through FERC Order Nos. 890 and 1000. Order No. 890 (2007) required that transmission planning be open to stakeholders. Order No. 1000 (2011) added interregional coordination, competition among transmission owners, and cost allocation reform. Order No. 1000 also enables transmission projects that support public policy goals, such as moving renewable energy from distant sources to load centers.

Equitable cost allocation among customer beneficiaries, especially for larger and interregional transmission investments, is a significant challenge in the implementation of the FERC Order No. 1000 regional planning process. Differing regional approaches to meeting FERC Order No. 1000 principles for cost allocation—particularly the definition of "beneficiary"—have made the implementation of Order No. 1000 complex. The implementation of FERC Order No. 1000 regional cost allocation principles is relatively new, so it is hard to assess the effectiveness of the process to date in achieving public policy goals. Going forward, more systematic monitoring of activities and systematic data collection will be needed to assess whether Order Nos. 890 and 1000 are achieving their goals.

Low- and Zero-Carbon Power Generation

A consistent theme from a vast body of climate science research suggests that deeper decarbonization is necessary to reduce emissions sufficiently to minimize the most serious impacts of climate change.[24] This will require, in part, an enhanced portfolio of lower- and zero-carbon generation technologies, such as renewables, nuclear power, and fossil generation with carbon capture, utilization, and storage (CCUS).

The national and regional generation mix has changed over the past few decades (Table 3-1), and additional changes are projected for 2040. In 2005, the top six generation sources in descending order were coal, nuclear, gas, hydro, petroleum, and non-hydro renewables. Natural gas and non-hydro renewables, especially wind and solar, have become much more prominent in the fuel mix, largely due to low-cost, abundant natural gas supplies, lower-cost wind and solar generation technologies, and a range of Federal and state policies that provide incentives for a range of clean generation technologies. Comparing the costs of different electric generating technologies is challenging, particularly as the costs of many technologies and fuels vary due to the interplay of innovation, policy, markets, and future uncertainty. One common approach is to compare technologies using the levelized cost of electricity (LCOE).[25] There are limitations to using LCOE, particularly for capital-intensive technologies, as this metric is sensitive to assumptions about the cost of capital, among other factors.[e]

Table 3-1. Change in Generation from Major Fuel Type, 2009–2014[26]

	Coal		Natural Gas		Nuclear		Non-Hydro Renewable		Total	
	Absolute Change (TWh)	Percent Change	Absolute Change (TWh)	Percent Change	Absolute Change (TWh)	Percent Change	Absolute Change (TWh)	Percent Change	Absolute Change (TWh)	Percent Change
U.S.	-171.3	-10	204.6	22	-1.7	0	130.8	85	132	3
WECC	-13.8	-6	-4.3	-2	-10.3	-15	43.4	92	11.9	2
SERC	-53.9	-11	94.8	51	3.8	1	12.7	52	49.8	5
RFC	-83	-15	65.1	85	12.1	5	17.5	102	13.5	1
NPCC	-17.4	-62	11.8	12	0.2	0	14.5	148	-6.4	-2
SPP	-0.8	-1	-5.7	-10	-0.2	-2	4	29	3.4	2
MRO	-9.6	-6	2.7	31	-3.9	-11	19.2	105	12.2	6
FRCC	-4.1	-7	30.6	29	-1.2	-4	0	-1	9.7	4
TRE	11.4	10	9.7	6	-2.2	-5	19.4	105	37.8	12
Alaska	-0.1	-11	-0.3	-8	0	0	0.2	1,484	-0.7	-10
Hawaii	0	1	0	0	0	0	0.5	74	-1.3	-12

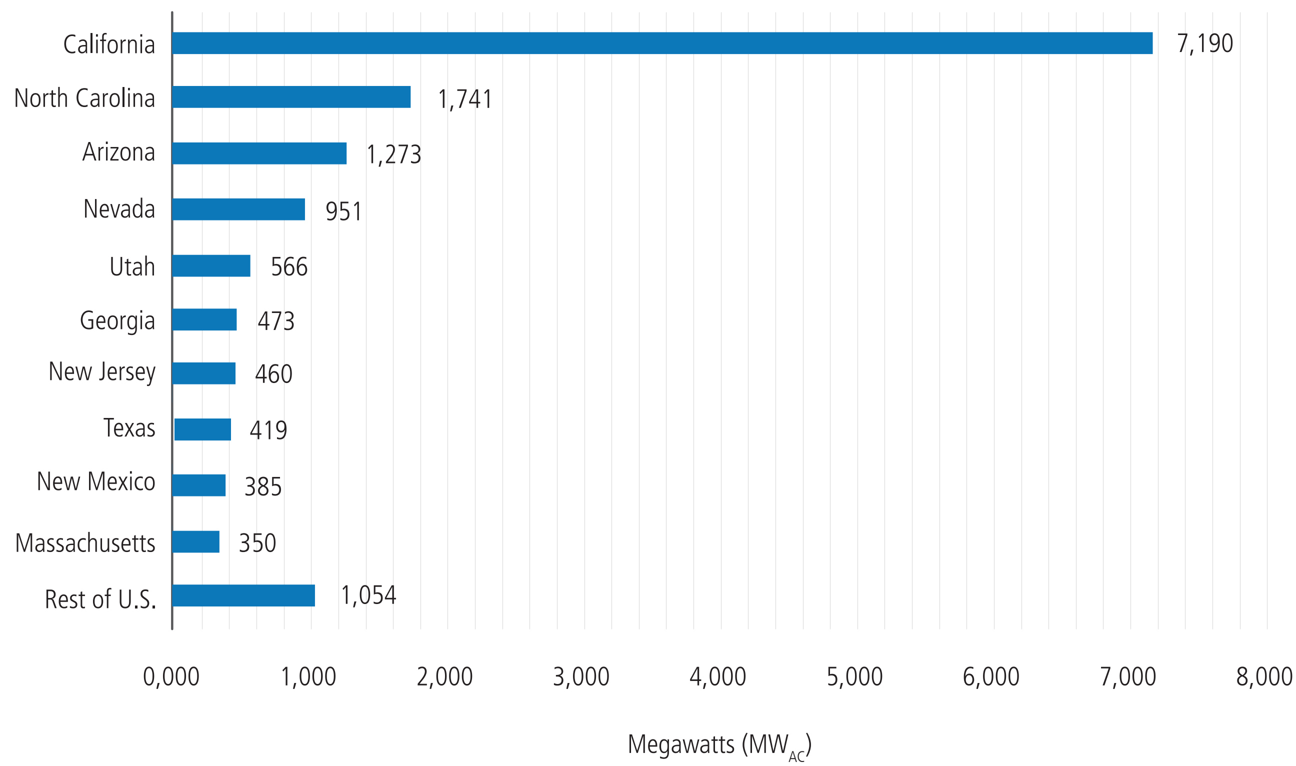
In recent years, the electricity generation mix in the western United States has shifted from fossil fuels and nuclear power to non-hydro renewables. In the eastern part of the United States, generation has shifted primarily from coal to natural gas. Texas has seen a growth in generation from both coal and non-hydro renewables. Acronyms: terawatt-hours (TWh), Western Electricity Coordinating Council (WECC), SERC Reliability Corporation (SERC), ReliabilityFirst Corporation (RFC), Northeast Power Coordinating Council (NPCC), Southwest Power Pool (SPP), Midwest Reliability Organization (MRO), Florida Reliability Coordinating Council (FRCC), Texas Reliability Entity (TRE).

[e] For a discussion of the limitations of LCOE, see Energy Information Administration (EIA), *Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2016* (Washington, DC: EIA, 2016), 1, http://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf.

Wind and Solar: Zero-Carbon Variable Energy Resources (VER)

Cumulative wind capacity has grown from 25 gigawatts (GW) in 2008 to 74.4 GW in 2015.[29] In 2015, wind accounted for 41 percent of new electric generation capacity in the United States and provided 4.7 percent of total electricity generation.[30, 31, 32] Similarly, utility-scale solar generation capacity has grown from less than 0.1 GW in 2008 to 11.9 GW in 2015, a factor of over 168.[33] There are now over 1 million installed photovoltaic (PV) systems across the United States.[34, 35] The Energy Information Administration estimates that total U.S. solar net generation (PV and thermal) was 4.7 million MWh in October 2016, with 33.94% of that total coming from distributed solar PV.[36]

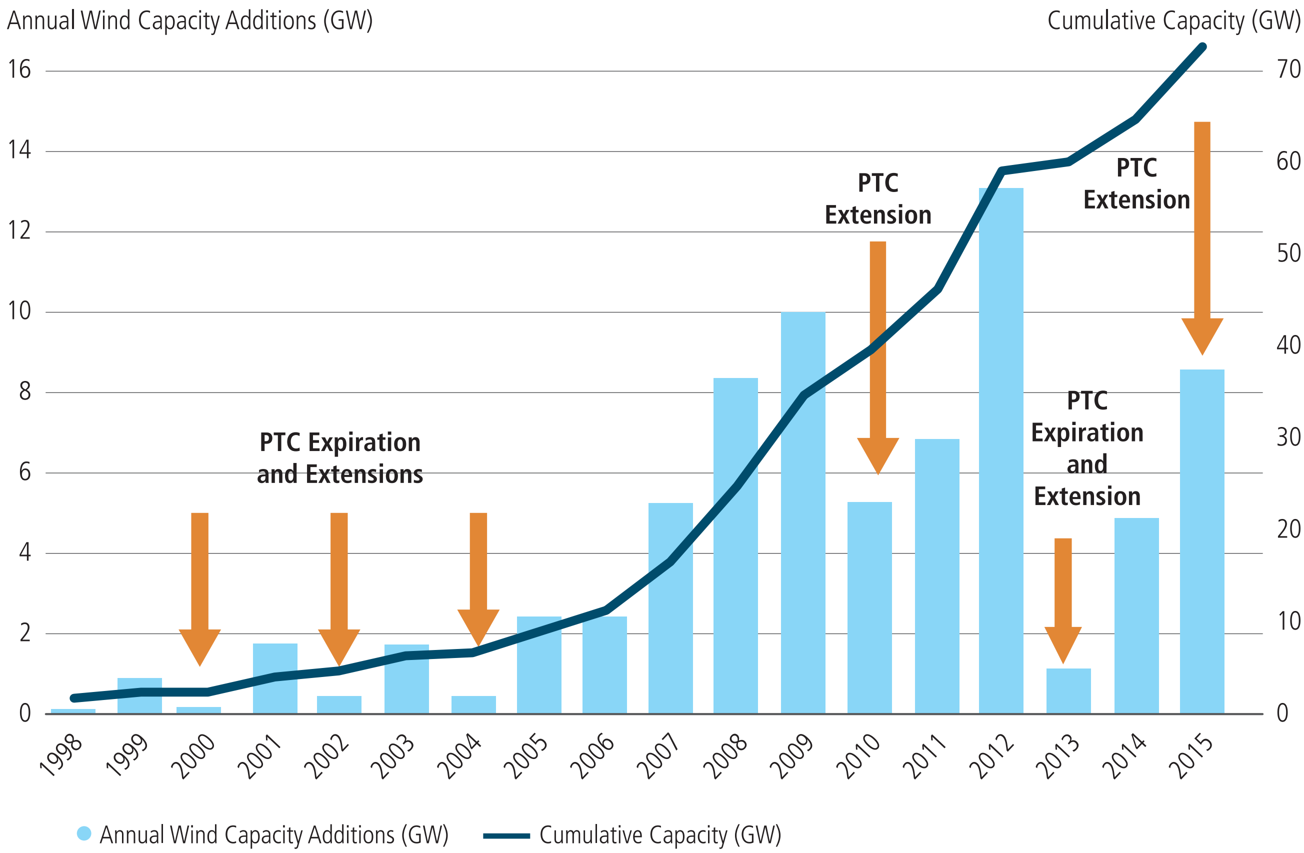
Figure 3-3. Utility-Scale PV Installed Capacity, Top 10 States, August 2016[37]



Utility-scale PV installed capacity is distributed unevenly across the United States. California comprises almost half of the installed utility-scale PV capacity in the country, followed by North Carolina, and the Southwest of the United States with Arizona, Nevada, and Utah. MW_{AC} denotes alternating-current megawatts.

The price of installed residential- and utility-scale solar PV is projected to fall below \$2 per W_{DC} (direct-current wattage) and \$1.15/W_{DC}, respectively, in the next 10 years. Solar PV electricity generation is projected to grow by a factor of 17 from 2015 to 2040 and reach an installed capacity of over 100 GW.[38] The Department of Energy's (DOE's) SunShot program has a goal of achieving an LCOE of 6 cents/kWh) for utility-scale PV in 2020 and 3 cents/kWh by 2030.[39] Despite the rapid growth of distributed- and utility-scale PV, these resources contribute generation equivalent to about 0.4 percent and 0.6 percent of U.S. demand, respectively.[40, 41] In the United States, California dominates solar PV with about 50 percent of the Nation's installed capacity (Figure 3-3), due in large part to legacy statewide incentive programs, such as the California Solar Initiative, as well as the state's high retail electricity rates and solar resource potential.

Figure 3-4. Relationship between the Production Tax Credit and Annual Wind Capacity Additions[42]



The Production Tax Credit (PTC) has accelerated wind project deployment significantly—between 2000 and 2013, cumulative wind capacity grew from under 5 GW to over 60 GW—though capacity additions noticeably track the PTC expiration and extension schedule.

Technology improvements in wind turbines—including taller turbines, longer blades, and advanced turbine designs—have enabled substantial cost reductions for wind power. Power purchase agreements for wind have fallen from rates as high as 7 cents/kWh in 2009 to around 2 cents/kWh inclusive of the Production Tax Credit (PTC) in 2015, driven by wind deployment in excellent resource locations in the interior regions of the country.[43] It is also projected that these technology improvements will enable an expansion of the geographic distribution of wind power's technical potential to new regions of the United States.[44]

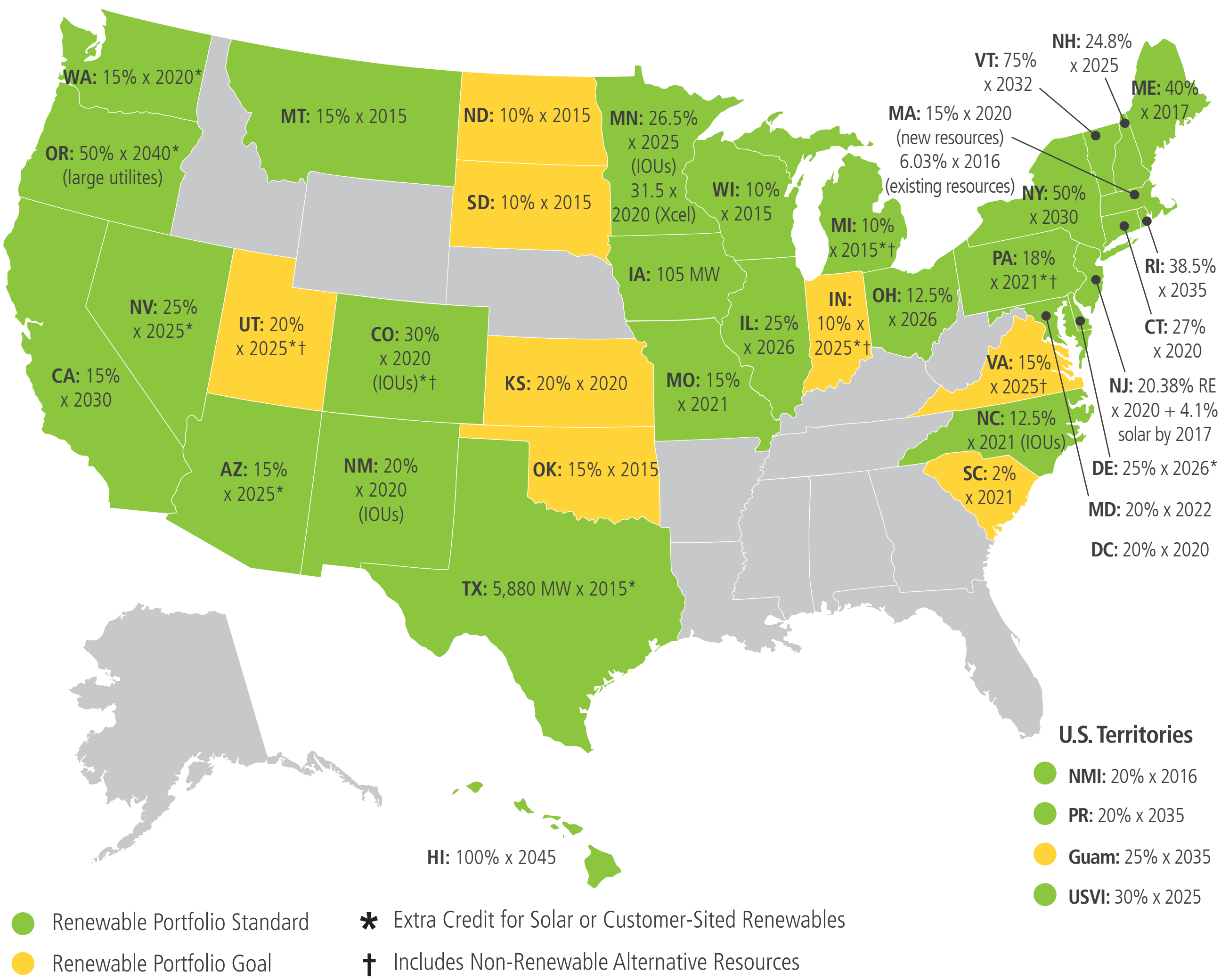
Declining costs for wind and solar have been spurred by industry innovation as well as a variety of Federal and state policies that accelerate deployment. Major policies include the renewable energy tax credits at the Federal level and the renewable portfolio standards (RPS) at the state level. At the Federal level, the Investment Tax Credit (ITC) and PTC established under the Energy Policy Act of 1992 are two key Federal tax incentives that have been instrumental in accelerating the construction of renewable electricity projects. Both of these incentives are designed for use by entities that pay Federal taxes and are subject to strict treatment under both the Internal Revenue Code and generally accepted accounting principles. These attributes have major implications for who utilizes the incentives and how projects are developed. Because they do not pay Federal income taxes, entities like municipal utilities and cooperative utilities cannot currently monetize these tax credits. For regulated utilities, the Internal Revenue Service requires that any ITC benefits be normalized[f] for ratemaking purposes. The net result of these nuances is that independent developers have played an outsized role in the deployment of wind and solar relative to previous technologies.

[f] Normalization requires that a tax credit be realized across the life of an asset, instead of immediately.

In December 2015, the ITC and PTC were both extended by 5 years through 2021 and 2019, respectively, with each tax credit on a different declining schedule. Solar system owners have primarily claimed the ITC, while wind power, which has higher capacity factors and lower capital costs, has benefitted from the PTC (Figure 3-4). A recent National Renewable Energy Laboratory (NREL) study estimates that the December 2015 extension of the ITC and PTC could result in an additional 53 GW of renewable electricity capacity by 2020 as compared to a case with no tax credit extensions, corresponding to 540 million metric tons of avoided CO_2 cumulatively by 2030, again compared to the no extension case.[45]

State RPS policies are also key drivers of renewable energy growth. Twenty-nine states have renewable or alternative energy portfolio standards that require utilities or other electricity providers to meet a minimum portion of load with qualifying forms of renewable energy (Figure 3-5)[46] Of the 230 terawatt-hours (TWh) of total non-hydro renewable electricity generation growth since 2000, over half (or 130 TWh) was to meet RPS mandates.[47]

Figure 3-5. State RPS Policies, August 2016[48]



Twenty-nine states and the District of Columbia have an RPS, and an additional eight states have a renewable portfolio goal; some include extra credit for solar or customer-sited renewables or include nonrenewable alternative resources. The RPS or renewable portfolio goals are key drivers of renewable energy growth.

Acronym: IOU – investor-owned utility

RPS rules vary from state to state, each with different targets, timeframes, and sometimes specific carve outs for solar or distributed generation (DG). Almost half of the mandated renewable energy capacity (under existing RPS) is located in California, "reflecting the rapid and recent build-out of renewable capacity to meet 2020 RPS targets, including the completion of a number of large utility-scale PV projects."[49]

In addition to state-level RPS, some states have instituted electricity resource standards that set requirements for "clean" or "alternative" energy, which include not only renewables, but also certain nonrenewable technologies, such as nuclear power and coal with CCUS. These are sometimes referred to as Clean Energy Standards (CESs). States that have implemented these include Colorado, Michigan, Illinois, New York, Ohio, Pennsylvania, and Utah.[g] There have been proposals for a Federal CES introduced in previous Congresses.

Renewable Energy Certificates (RECs) are tradeable certificates used to demonstrate and verify the use of renewable electricity in the United States, usually to meet state RPS and sometimes to meet voluntary renewable goals. While generated concurrently with renewable electricity, RECs can be traded separately from the underlying electricity. While requirements for eligible resources vary from state to state, one REC is issued for each MWh of electricity generated from an eligible renewable energy resource. By obtaining and retiring (i.e., preventing further trading of) an REC, a utility or customer can claim it for compliance with an RPS or for voluntary purposes. REC tracking systems, available throughout the country, ensure that no claims on this renewable energy are counted twice. In 2015, over 210 million RECs were projected to be generated to meet state RPS requirements.[50] An additional 78 million voluntary RECs were generated and retired for voluntary purposes by residential and commercial customers.[51]

Analysis indicates that new renewable electricity resources that were used to meet all state RPS obligations totaled 5,600 megawatts (MW) of capacity additions, as well as 98 TWh of generation in 2013.[52] One life-cycle GHG emissions analysis indicates that this new renewable electricity generation helped to avoid 59 million metric tons of CO_2 equivalent in 2013.[53] These policies are commonly highlighted by states as having strong potential to create jobs.[54] A 2016 study estimated that RPS created 200,000 gross domestic renewable energy jobs in 2013.[55]

In order to fully realize the potential emission reduction benefits of high levels of zero-carbon VER, these VER must be integrated into the grid and provide grid services. Currently, wind and solar plants are only required to provide grid services in certain regions.[h] Smart power converters for wind resources and smart inverters for solar resources could provide several services to assist in their integration into the grid.[56, 57, 58, 59, 60, 61, 62] California ISO, Midcontinent ISO, PJM Interconnection, ISO-New England, and New York ISO are all making efforts to integrate zero-carbon VER, for example, by developing or improving mechanisms to provide and support (1) flexible ramping (i.e., the integration of flexible ramping products into their markets) or (2) incentives for reliable capacity.[63]

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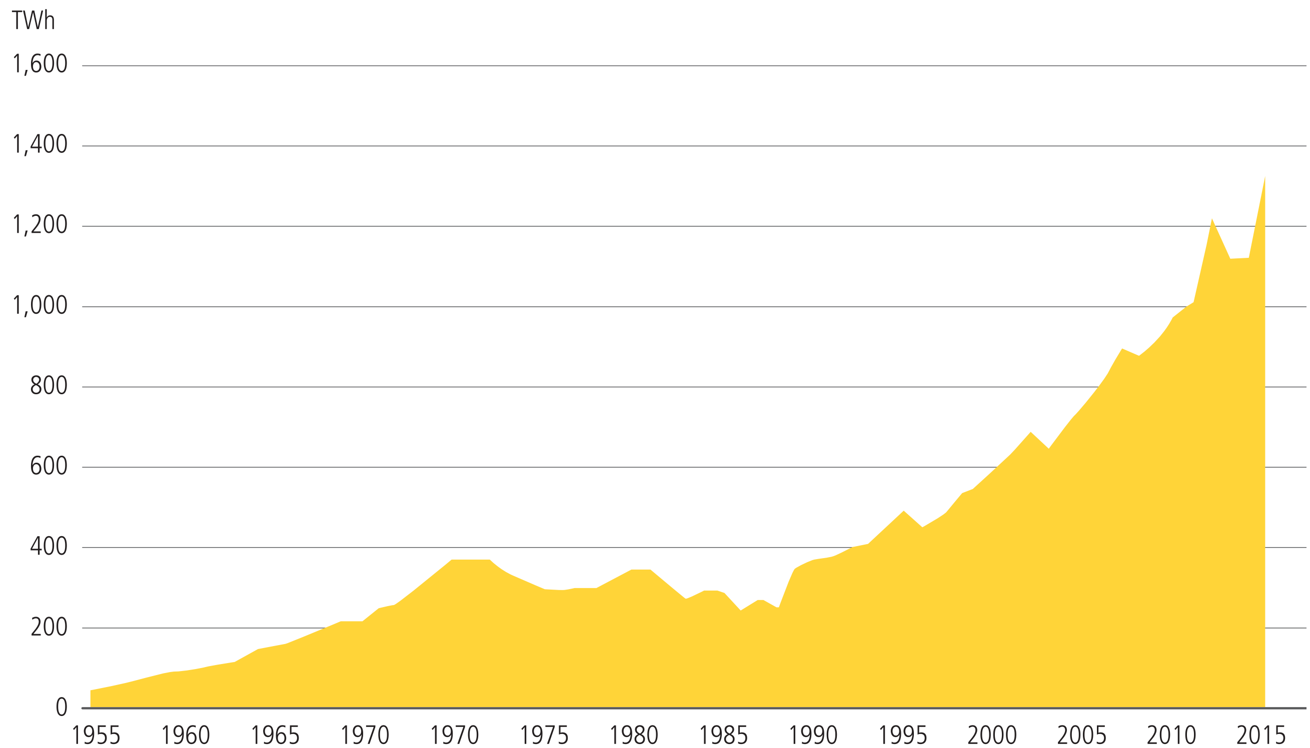
[g] In 2016, two states, Illinois and New York, put policies in place to incentivize the continued operation of existing nuclear plants.

[h] In November 2015, the North American Electric Reliability Corporation issued five general recommendations as part of its "Essential Reliability Services Task Force Measures Framework Report," which focus on the incorporation of these services into the design of variable generating resources in the future. Shortly thereafter, on February 18, 2016, FERC issued a Notice of Inquiry, Docket RM16-6-000, seeking comment on the need to reform its regulations for the provision and compensation of primary frequency response. Source: North American Electric Reliability Corporation (NERC), *Essential Reliability Services Task Force Measures Framework Report* (Atlanta, GA: NERC, November 2015), http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSTF%20Framework%20Report%20-%20Final.pdf; Federal Energy Regulatory Commission (FERC), *Docket No. RM16-6-000, Essential Reliability Services and the Evolving Bulk-Power System—Primary Frequency Response* (Washington, DC: FERC, February 16, 2016), https://www.ferc.gov/whats-new/comm-meet/2016/021816/E-2.pdf.

Natural Gas Generation: Lower-Carbon Flexible Baseload

Natural gas generation is projected to become the largest source of U.S. electricity in 2016, overtaking coal for the first time on an annual basis.[64] In 2015, natural gas–fired generation accounted for approximately 33 percent of total U.S. generation (Figure 3-6).[65] The availability of low-cost, domestic fuel; low capital costs; existing infrastructure; and relative generation flexibility have contributed to this increase. The shift towards natural gas generation resulted in 1,254 million metric tons of avoided CO_2 emissions from 2005 to 2014, or about 61 percent of total avoided emissions over that time period.[66] On a life-cycle basis, a new NGCC plant emits roughly 50 to 60 percent less CO_2 than a typical existing coal-fired power plant.[i, 67]

Figure 3-6. U.S. Natural Gas Generation, 1950–2015[68]



Natural gas–fired generation has grown nearly continuously since the late 1980s

NGCC generators are very efficient, have unused capacity, and have significantly higher capacity factors than natural gas combustion turbines (CTs), which contribute primarily to peak load and may only operate for a few hours a year (Figure 3-7). Until recently, most NGCC units were utilized for intermediate and peak loads, rather than baseload. Because natural gas prices have been low for a sustained period, and because NGCC

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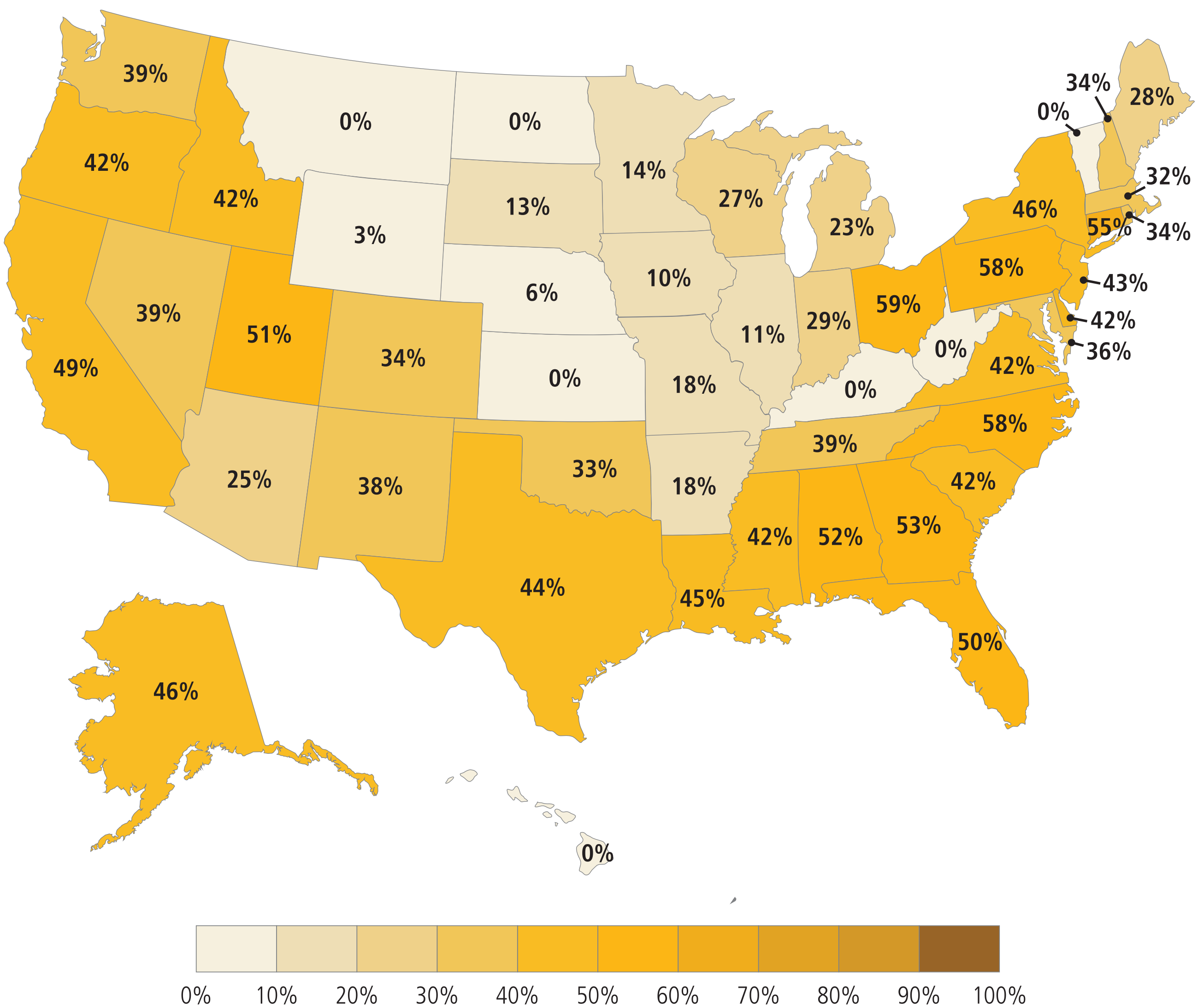
[i] Life-cycle GHG emissions from natural gas–fired electricity generation are significantly lower than from coal-fired units. This is true even when accounting for methane emissions from natural gas and coal, a wide range of variability in the performance of equipment and operations, and the timing of impact to radiative forcing in the atmosphere. Furthermore, there are a number of ongoing policy efforts—including those outlined in the first installment of the Quadrennial Energy Review (QER 1.1), Chapter VII (*Addressing Environmental Aspects of TS&D Infrastructure*)—that are contributing to further reducing methane emissions from natural gas, making natural gas's relative advantage even greater. These include recently finalized regulations by the Environmental Protection Agency (EPA), the Department of the Interior, EPA's voluntary Methane Challenge Program, and several new programs at DOE to help improve quantification of methane emissions and expand related research and development (R&D).

plants retain some of the flexible characteristics of CTs and operate at a higher efficiency and lower cost, these units are now often used for baseload power.

A CT's short startup times and fast ramp rates makes it essential for maintaining grid reliability, absent affordable grid-scale storage. Capacity factors for CTs are quite low (generally below 10 percent), but when operating, they can be significant contributors to conventional air pollutants.[69] Single-cycle gas turbines can go from cold startup to 100 percent output in 7–11 minutes; in contrast, coal-fired units ramp on the order of hours, and doing so incurs increased operations and maintenance costs.[70] NGCC ramp rates fall somewhere in between, and some NGCC units can ramp to full rated power in less than 30 minutes.[71] This flexibility makes CTs useful in complementing variable generation, especially for solar, because this flexibility complements the high peaks associated with solar generation and allows for load following. Some states rely on CTs more regularly than other locations; most notably, Texas, Louisiana, Wyoming, New Hampshire, Maine, and Rhode Island all have CT capacity factors greater than 20 percent.[72]

Figure 3-7. NGCC Capacity Factors by State, 2014[73, 74]



Capacity factors of NGCC plants all generally increased across the United States between 2010 and 2014, and many states have constructed or are planning to construct new NGCC plants after 2014. Significant potential exists to further increase generation from NGCCs in most states. In the figure, "0%" represents states with no NGCC capacity.

A recent study of the value of fast-ramping gas for supporting variable renewables noted that, "…to date FRF [fast ramping fossil] technologies have enabled RE [renewable energy] diffusion by providing reliable and dispatchable back-up capacity to hedge against variability of supply...renewables and fast-reacting fossil technologies appear as highly complementary and…should be jointly installed to meet the goals of cutting emissions and ensuring a stable supply."[75]

It is also important to note that the changing generation mix and growing reliance on natural gas generation is also increasing the need for and value of demand response (DR). ISO-New England has, for example, developed a Winter Reliability Program to incentivize DR, among other things, in order to protect natural gas customers during extreme cold weather events. Another example: New York ISO can activate DR programs in the winter to increase reliability and decrease winter demand.[76] DR is discussed in greater detail in Chapter IV (*Ensuring Electricity System Reliability, Security, and Resilience).*

Coal, Natural Gas, and Biomass Generation with CCUS: Low-Carbon Baseload

Though there is international consensus that CCUS for coal, natural gas, and biomass generation will likely be required to realize the emission cuts needed to limit global warming,[77] investment in and deployment of CCUS technology lags behind other clean energy technologies, primarily due to cost.[78] The United States is a global leader in enhanced oil recovery (EOR), with the largest CO_2 pipeline network in the world. CO_2 used for EOR has provided important revenue streams for CCUS projects but has been insufficient to support substantial deployment. Stronger CCUS deployment policies would help to provide the market certainty and financing needed for deployment and to develop supply chains, infrastructure, and ultimately, expanded private-sector investment in CCUS technologies. Continued RD&D is also critical to improving performance and driving down the costs of CCUS technologies.

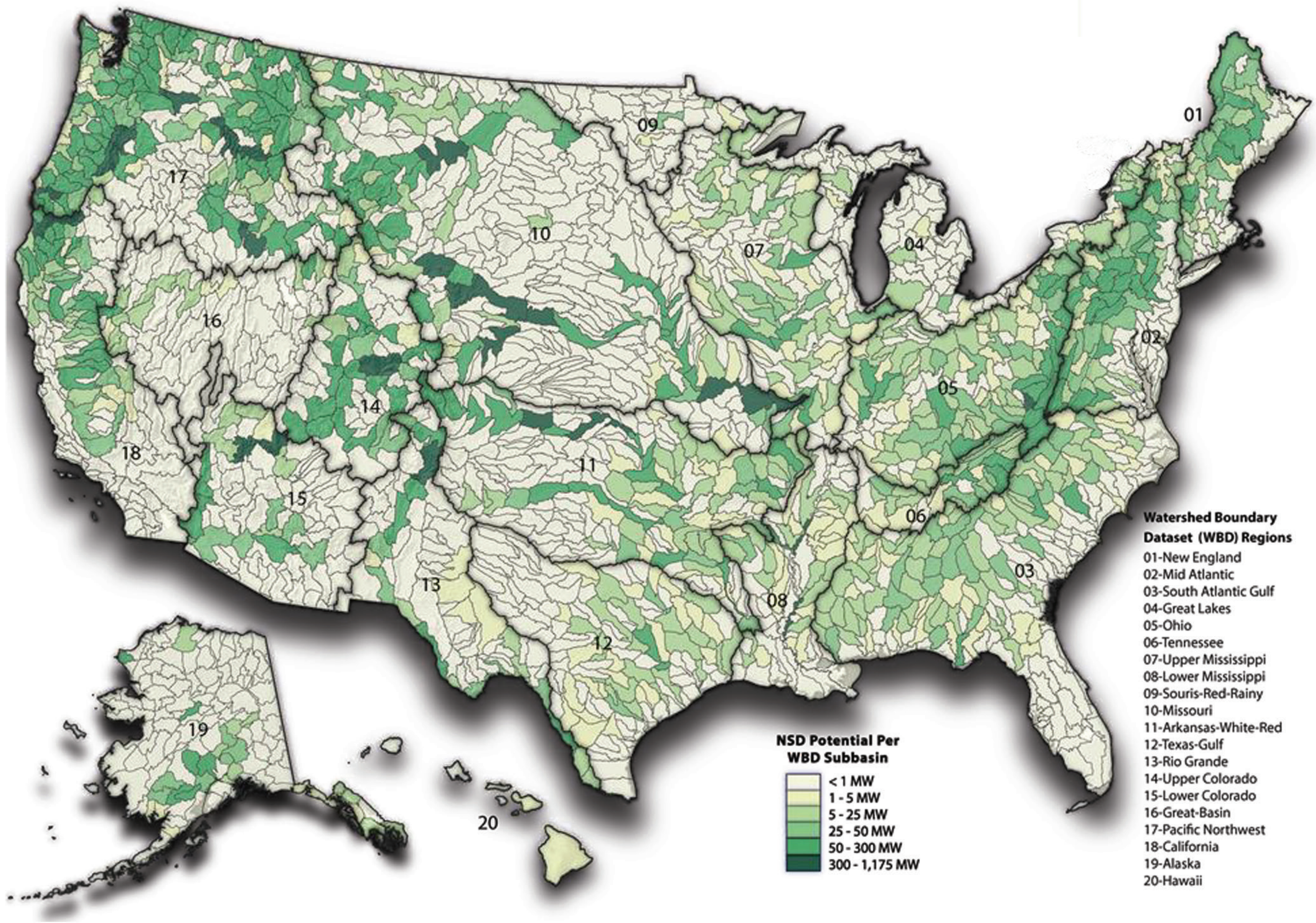
Hydropower: Zero-Carbon Baseload and Flexibility Resource[j]

In 2014, there were 79.6 GW of installed hydropower capacity from conventional facilities in the United States and 21.6 GW from pumped storage hydropower.[79] The average capacity factor of conventional hydroelectric generators was 40 percent. In 2016, the technical resource potential for new hydropower developments was calculated to be 65.5 GW, focused largely in the Pacific Northwest and Rocky Mountain West (Figure 3-8).[80] The technical resource potential for powering currently nonpowered dams is 12 GW, an increase of 15 percent over the existing fleet. This potential is focused mainly on the Mississippi River and its major tributaries, such as the Ohio and Red Rivers.[81] Upgrades and optimization for existing hydropower facilities could provide an additional 5.6 GW by 2030, or an 8 to 10 percent increase, of increased generation capacity through turbine efficiency improvements and facility optimization.[82] As of 2015, hydropower comprises approximately 20 percent of U.S. zero-carbon generation.[83]

About half the U.S. hydroelectric fleet is over 50 years old since many large dams were built between the 1940s and 1960s (Figure 3-9).[84] However, with routine maintenance and refurbishment of turbines and electrical equipment, the expected life of a hydropower facility is likely to be 100 years or more.

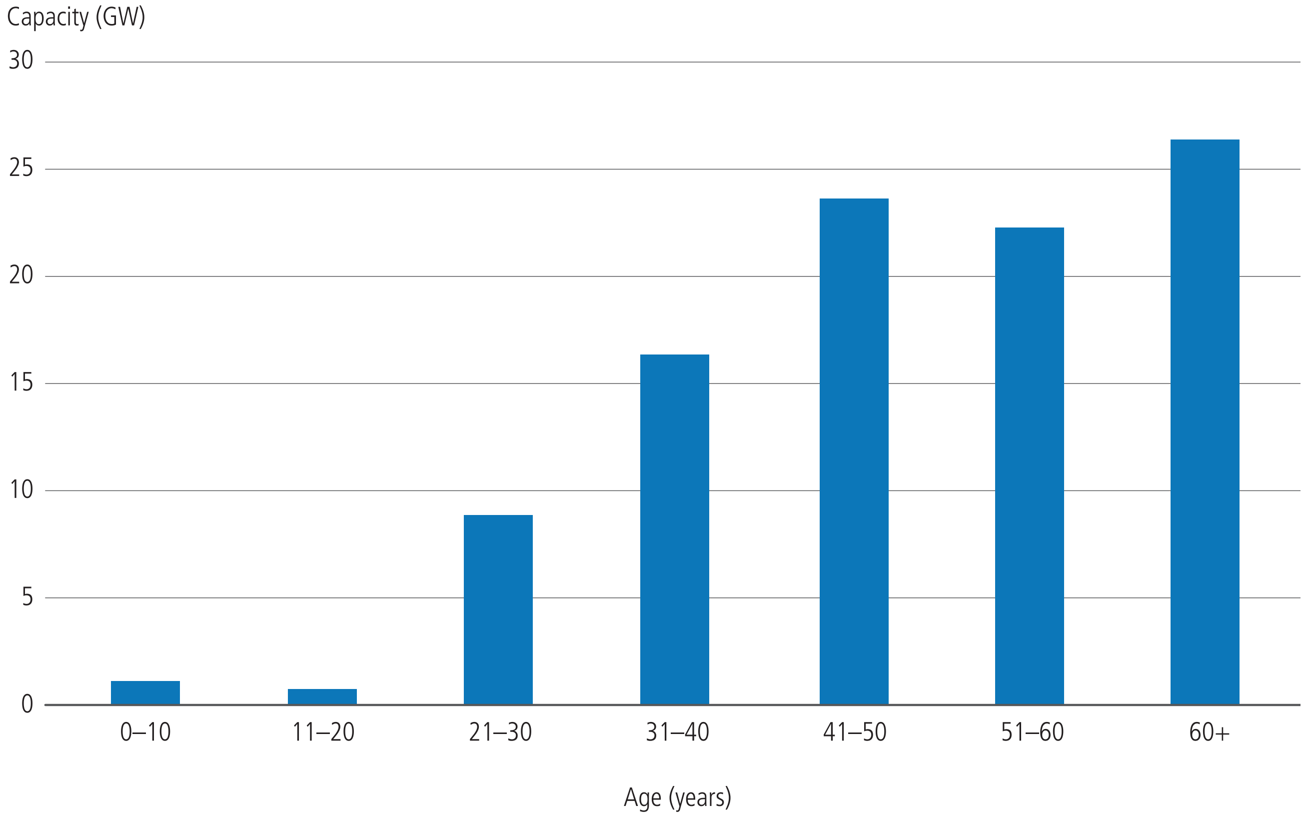
[j] Renewable energy sources that have zero emissions from generation can result in marginal emissions when evaluated through a life-cycle analysis; for example, see Department of Energy (DOE), *Hydropower Vision: A New Chapter for America's First Renewable Electricity Source* (Oak Ridge, TN: DOE, 2016), https://energy.gov/sites/prod/files/2016/10/f33/Hydropower-Vision-10262016_0.pdf.

Figure 3-8. U.S. New Stream-Reach Development Potential by Sub-Basin for the United States[85]



The technical resource potential for new hydropower developments is 65.5 GW, focused largely in the Pacific Northwest and Rocky Mountain West.

Figure 3-9. Age Profile of U.S. Hydropower Generation Fleet, 2014[86]



About half the U.S. hydroelectric fleet is over 50 years old. Many large dams were built between the 1940s and 1960s.

There has been a renewed interest in the flexibility benefits that many hydropower projects can offer the grid, given the growth in variable renewable sources, especially wind. A recent report notes that about half of all installed hydropower capacity (39 GW) has high flexibility potential and could play an important role in low-cost integration of variable renewable generators.[87] Pumped hydropower storage can be used in peaking and balancing applications to maintain grid reliability and can play a balancing role in areas with high penetrations of VER.

Large-scale hydropower projects are often difficult to finance due to high capital costs, lengthy permitting periods, and environmental concerns. While the prospects for building very large, new dams are low, there are other opportunities for hydropower to expand in the U.S. generation portfolio. Upgrading equipment at existing sites to expand capacity is likely to continue, and projects at currently nonpowered dam sites could continue to advance. Modern low-impact, environmentally sustainable technologies, such as water-efficient and "fish-friendly" turbines, or run-of-river approaches have the potential to increase hydropower generation. Such upgrades and optimization for existing hydropower facilities could provide an additional 5.6 GW nationally, although individual facilities have seen generation increases of 35 percent with investment payback periods under 2 years.[88] Still, the amount of new hydropower capacity that is expected to come online over the near to mid-term is relatively modest when compared to wind and solar.

Over the next 10 years, existing FERC licenses will expire for nearly 250 hydropower projects. These expiring facilities total more than 16,000 MW, or nearly 20 percent of the existing installed capacity. It takes an average of 5 to 8 years to relicense an existing hydro project, with at least 3 years of pre-filing activity and then at least another 2 years after the application is filed. Only 2,198 dams are currently used for hydroelectricity—3 percent of the Nation's total dams. (Other uses for dams include navigation, flood control, irrigation, and recreation.) Adding hydroelectricity to these preexisting dams would increase hydro generation by 15 percent, and these preexisting dams may not face as many siting constraints because some of the environmental impacts from dam construction have already been incurred. Such additions, combined with the ability to leverage and upgrade existing infrastructure at nonpowered dams, which would increase hydro generation by 8 to 10 percent, provide significant opportunities to increase hydropower generation while reducing costs and environmental impacts.[89]

Biomass: Net-Zero Carbon Renewable Baseload and Flexibility Resource

Biomass fuels include a broad range of sources, including wood and wood-derived fuels, black liquor (primarily pulp residuals in the paper production process), municipal solid wastes, landfill gas, and others. If the emissions from combusting biomass are fully offset by the sequestration of CO_2 as the biomass is grown, when accounting for the carbon flows in production and processing of the biomass, biomass electricity can be a low-carbon resource. Biopower plants are typically fully dispatchable and are generally dispatched as baseload generation if variable and fuel costs are low enough. Biomass sources can either be directly combusted, gasified to produce a synthetic fuel, or co-fired at a small amount (typically up to 10 percent heat content) with a conventional fuel such as coal.[90] In 2015, electricity generation from biomass across all sectors accounted for 11.3 percent of renewable electricity generation and 1.6 percent of total electricity generation in the United States. A significant number of biomass facilities are small enough that they can be located near their fuel sources. As such, nearly half of the electricity generated from biomass in 2015 was at industrial facilities outside of the electric power sector, such as pulp and paper mills. Generation from biomass across all sectors grew from 56 TWh in 2010 to 64 TWh in 2015, driven primarily from new capacity in southern states, such as Virginia, Florida, and Georgia.[91]

Geothermal Generation: Zero-Carbon Baseload and Flexibility Resource

Geothermal generators are baseload plants capable of providing valuable services to the grid, such as generation flexibility. Prior to 1980, geothermal generation remained below 5 TWh annually. Between 1980 and 1989, generation tripled to 15 TWh as new facilities came online. Much of the early growth in geothermal power was driven by Public Utility Regulatory Policies Act incentives, although this driver has declined over time as the avoided costs of utility generation have fallen. As of 2015, geothermal power continues to generate roughly 15 TWh of electricity annually, or roughly 0.4 percent of total U.S. electricity generation.[92, 93] Challenges in exploring new "blind" hydrothermal resources and long drilling times for production wells have led to increased uncertainty for investors in large geothermal projects. Additionally, tax credits that are only extended for short periods of time do not take into account the long lead time of geothermal project development, scarcity of power purchase agreement opportunities, or need for transmission infrastructure. Current ancillary service compensation models in areas with the most geothermal development do not provide sufficient revenue to warrant the increased operational and control retrofitting expenses. If appropriately valued, the services a geothermal plant can provide include regulation, load following, spinning reserves, non-spinning reserve, and replacement or supplemental reserve.[94]

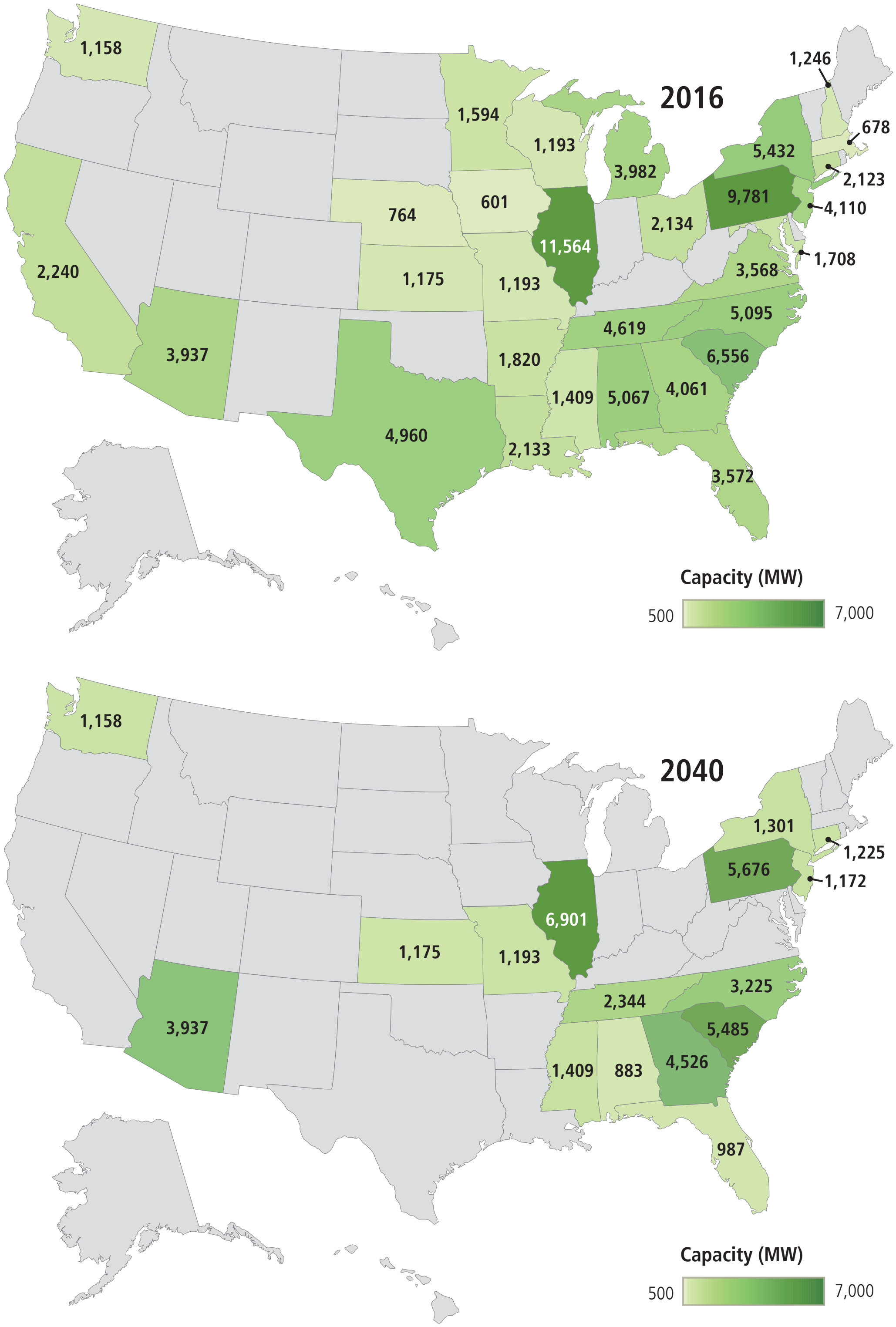
Nuclear Generation: Zero-Carbon Baseload

Nuclear generation comprises 60 percent of the Nation's current zero-carbon generation.[95] The current operating nuclear power fleet consists of approximately 54 GW of generating capacity in regulated markets and 45 GW in restructured electricity markets.[96] Of the 99 operating nuclear reactors in the United States, so far, 80 have been approved to (and plan to) operate for 60 years, while another 9 currently have applications under review by the Nuclear Regulatory Commission (NRC).[k, 97] The timeline for these units to reach the end of their 60-year license is as follows: 6 units between 2029 and 2030; 27 units between 2031 and 2035; 15 units between 2036 and 2040; 20 units between 2041 and 2045; and 12 units between 2046 and 2050.[98] Forty-eight units will reach the end of their licensed lifetime by 2040, the timeframe covered by the second installment of the Quadrennial Energy Review (QER 1.2) (Figure 3-10).[l, 99] Without renewals to 80 years, there will be a significant loss of zero-carbon generation starting in the 2030s. Also, if these plants were to all request a license renewal to 80 years, it would represent a significant additional workload for NRC staff and commissioners. Two plants, Surry Power Station and Peach Bottom Nuclear Generating Station, have announced intentions to seek subsequent license renewals, and others are also expected to do so.

[k] Diablo Canyon 1 and 2 are under review, but Pacific Gas & Electric Company has announced it will withdraw the application

[l] These are the end dates with first license renewal.

Figure 3-10. Current and Projected Nuclear Capacity Assuming No Subsequent License Renewals[100, 101]



The top map in the figure shows U.S. nuclear power capacity (in MW) by state in 2016 (as of December 15, 2016). The bottom map shows what the U.S. nuclear power capacity by state would be in 2040 (December 31, 2040), assuming that all reactors, except those that have already specified closure dates, shut down at the expiration of their currently approved licenses.

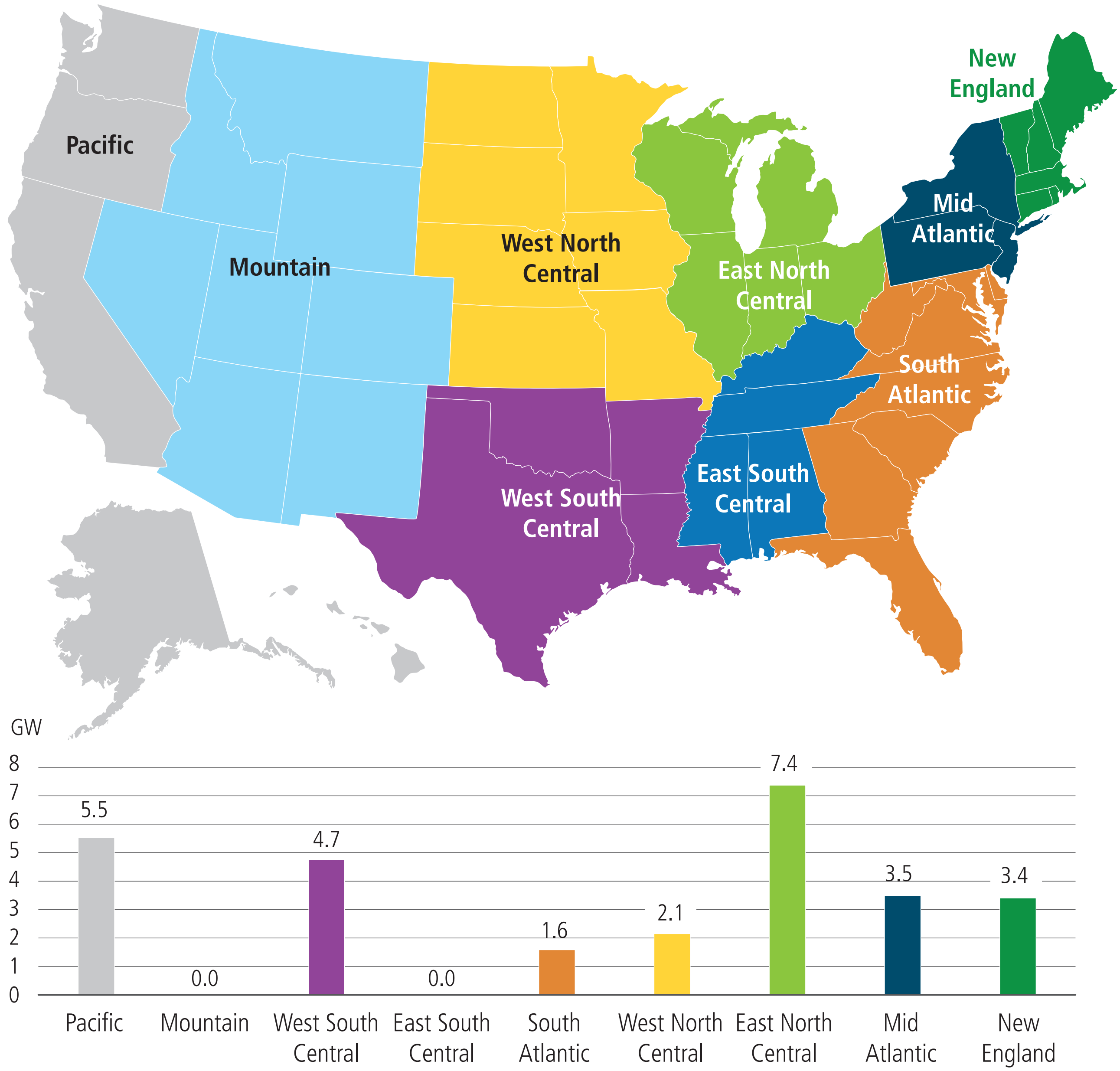
While estimates of the total amount of at-risk capacity vary, one recent analysis suggests that the capacity of retired or at-risk nuclear power plants by 2030 is about 28 GW, a little over one-quarter of U.S nuclear plant capacity; at-risk plant capacity varies by region, with the East North Central most affected (Figure 3-11).[102] Several nuclear power plants, particularly those with single units, face large recurring fixed costs. Some of these costs are due to post-Fukushima requirements, but many are simply the costs of operation, such as security, salaries, etc. Several plants have also needed large capital expenditures; faced with these significant costs, plant operators/owners have chosen to shut them down. Since 2012, when 104 reactors were operating, six units totaling 4.7 GW have shut down earlier than their licensed lifetime. Two retirements, San Onofre and Crystal River, have been driven by mechanical failures that were deemed too costly to repair; the others were market decisions. As of December 2016, 10 other units totaling 8.6 GW of capacity have announced plans to close in the next decade (though 6 of these units may not close because of recent state actions); 8 of those closures, with the exception of 2 units at Diablo Canyon, would occur prior to the expiration of the unit's existing licenses. Seven of the announced retirements, all those except Oyster Creek and Diablo Canyon, were attributed to market conditions.

In addition to plants with high recurring fixed costs, post-Fukushima, market structures have had significant impacts on the economics of nuclear generation. In states with restructured electricity markets, nuclear operators have found it to be increasingly difficult to compete under today's market conditions where electricity demand is flat or declining, natural gas prices and capital costs for new generation are low, wind and solar costs are declining, and state policies favor renewable generation. There are, however, new nuclear reactors under construction in vertically integrated markets. Watts Bar 2 entered service in Tennessee in 2016, and four additional reactors are under construction in Georgia and South Carolina that are projected to enter commercial operation in the 2019–2020 timeframe.

In 2016, two states, Illinois and New York, put policies in place to incentivize the continued operation of nuclear plants. The New York Public Service Commission finalized its CES on August 1, 2016, which contains a 50 percent renewable target by 2030, along with zero-emission credits (ZECs) for nuclear plants. The goal of the ZEC policy is to provide revenue support for three plants that had been at risk for premature retirement: Ginna, Nine Mile, and FitzPatrick. According to analysis from UBS, the ZEC policy would essentially guarantee revenue-positive operations for the three plants through a stable level of compensation.[103] Illinois enacted a similar policy as part of comprehensive energy legislation in December 2016.

The Secretary of Energy Advisory Board Task Force on the Future of Nuclear Power issued a report describing initiatives that would lead to a significant deployment of nuclear power in the 2030–2050 timeframe. It outlines programs and efforts for both new and existing nuclear power and also advanced reactor technologies that are not based on traditional light-water reactor designs.[104]

Figure 3-11. Nuclear Units at Risk or Recently Retired by Census Region[105]



Across the country, over 28 GW of nuclear generating capacity is at risk or recently retired, most of which is in the East North Central region.

It is important to weigh the costs of nuclear generation compared to other zero-carbon generation and to low-carbon natural gas generation to determine the relative value of at-risk nuclear generation units. A recent analysis estimated the "revenue gap"—the cost of incentives for keeping certain nuclear units running—for a discrete but representative set of nuclear power generating units.[106] DOE then analyzed the carbon emissions benefits of keeping this set of plants open by using a social cost of carbon of $41/metric ton. Assuming that all generation from retiring nuclear plants in this discrete set would otherwise be replaced with natural gas generation, keeping all but one of the nuclear units open would have higher benefits than costs. DOE's analysis only looked at the carbon benefits of at-risk generators; there are other, non-carbon benefits of retaining existing nuclear power, including jobs, reliability, and economic development benefits. Nuclear plants generally only shut down for maintenance activities, and forced outages are very rare.

The carbon intensity of the replacement generation for retiring nuclear plants is a key unknown. If the replacement generation is less carbon intensive than natural gas, fewer plants would pass this cost-benefit test. If the replacement generation is more carbon intensive, more plants would pass this cost-benefit test. It is possible that some coal may replace nuclear generation in specific regions. When analyzing the impacts of premature nuclear retirements on power generation in the state, a state of Illinois report considered a scenario in which 80 percent of the replacement generation was coal.[107] Other analysis concludes that roughly 75 percent of the at-risk nuclear generation nationwide would be replaced with fossil generation, largely powered with natural gas.[108]

Sufficiently favorable revenue, technology performance, policy, and market conditions enable financing for clean electricity systems. To accelerate the deployment of clean systems, Federal policies can address the barriers discussed in this section, which may create the conditions under which more clean resources can obtain financing. These policies include mechanisms that increase the financial return on clean energy projects, improve the financial profile of entities that participate in clean energy, or allow greater access to capital.

Decarbonization via Distributed Energy Resources

Distributed energy resources (DER) represent a wide range of generating or load-reducing technologies and programs that reside on a utility's distribution system or on the premises of an end-use consumer. DER can help reduce carbon emissions by providing electricity from low- or zero-carbon emitting technologies and by reducing demand. In addition, DER can also impact how much, and when, electricity is demanded from the grid, thereby supporting improved grid flexibility and load balancing. DER provide system reliability challenges and opportunities that are discussed in detail in Chapter IV (*Ensuring Electricity System Reliability, Security, and Resilience).* DER also provide business and consumer challenges and opportunities that are discussed in detail in Chapter II (*Maximizing Economic Value and Consumer Equity*).

Technical definitions of DER vary, but for the purposes of QER 1.2, DER are defined as DG, distributed storage, and demand-side management, including energy efficiency and DR. All DER can reduce carbon and other environmental impacts, but they do so in different ways. Energy efficiency provides environmental benefits by avoiding generation, transmission, and distribution and their associated environmental impacts. Clean DG provides environmental benefits by displacing higher-emitting generation. DR and distributed storage enable a cleaner grid by providing grid services with lower environmental impacts than other options for providing such services. The infrastructure needed to enable DER includes technologies that enable DR and improved demand control (e.g., smart meters, building automation systems, smart appliances, and direct load control technologies); highly efficient equipment and envelopes; DG systems (e.g., natural gas– and biomass-fired combined heat and power [CHP], waste heat recovery, backup generation, rooftop solar PV, small-scale wind power, geothermal); and distributed storage systems (e.g., vehicle to grid,[m] batteries, thermal, flywheels).[n]

Some DER, such as distributed solar PV and energy-efficient equipment, can have a significant impact on system load, but may not be under the direct control of grid operators. Other technologies, such as residential hot water heaters, have the potential to serve as DER as DR measures, but technologies enabling this resource have low penetration or are still nascent. Also, opportunities to improve energy efficiency and usage of DER

[m] Vehicle-to-grid configurations enable electricity to flow from the battery of a plug-in electric vehicle (PEV) to the grid and back to the vehicle.

[n] Not all DER are connected to a utility electric grid or can be controlled by grid operators. For example, resources deployed on some microgrids and CHP systems are still DER, despite lacking a grid connection. Note that the Energy Information Administration considers DER that are not connected to the grid as "dispersed generation" rather than "distributed generation." See Energy Information Administration (EIA), *Modeling Distributed Generation in the Buildings Sectors* (Washington, DC: EIA, August 2013), https://www.eia.gov/forecasts/aeo/nems/2013/buildings/.

vary by climate and household demographics, so tailoring programs to local needs is important. The West and South census regions, for example, where average household electricity consumption is higher than other regions,[o] are both experiencing high population growth rates.

Developments in DER and information and communications technologies (ICTs) can support an electric grid capable of much greater flexibility in managing both supply and demand. This can offer multiple value streams (e.g., energy, capacity, reactive power, frequency support, deferred utility capital expenditures, energy security, and avoided emissions). Smart grid technologies can also enable improved demand-side management and reduce carbon emissions. Analysis that sought to quantify the CO_2 benefits of 100 percent penetration of smart grid technologies by 2030 using nine different mechanisms suggests a possible 12 percent direct reduction in emissions (through implementation of the smart grid technologies that directly affect electricity and CO_2 emissions) and a 6 percent indirect reduction in emissions (translating the estimated cost savings in energy and/or capacity into their energy and carbon equivalents through purchase of additional cost-effective energy efficiency).[109] Transactive energy controls, smart charging of plug-in electric vehicles (PEVs), and other approaches to controlling load in response to grid conditions can contribute to both direct and indirect reductions in emissions. Table 3-2 shows the value of the various mechanisms analyzed.

Table 3-2. Potential Reductions in Electricity Sector Energy and CO_2 Emissions Attributable to Smart Grid Technologies, 2030[110]

Mechanism	Reductions in Electricity Sector Energy and CO_2 Emissions	
	Direct (%)	Indirect (%)
Conversion effect of consumer information and feedback systems	3	-
Joint marketing of energy efficiency and demand response programs	-	0
Deployment of diagnostics in residential and small/medium commercial buidings	3	-
Measurement & verification (M&V) for energy efficiency programs	1	0.5
Shifting load to more efficient generation	<0.1	-
Support for additional electric vehicles and plug-in hybrid electric vehicles	3	-
Conversion voltage reduction and advanced voltage control	2	-
Support for penetration of renewable wind and solar generation (25% RPS)	<0.1	5
Total Reduction	**12**	**6**

The combined impact of nine smart grid mechanisms, assuming 100 percent penetration of smart grid technologies by 2030, is a 12 percent reduction in annual U.S. electricity-related CO_2 emissions from direct effects, as well as a 6 percent reduction from indirect effects.[p]

[o] Electricity use for space heating is particularly high in the South census region. The South and (to a lesser extent) the West census regions also have high cooling loads.

[p] The direct reductions are calculated for the mechanisms that affected electricity and CO_2 emissions directly through implementation of the smart grid technologies. Indirect reductions are derived by translating the estimated cost savings in energy and/or capacity into their energy and carbon equivalents through purchase of additional cost-effective energy efficiency. This can represent a policy decision to reinvest the savings to purchase additional, more-cost-effective energy efficiency and renewable resources.

ICTs are enabling greater energy efficiency and its concomitant environmental benefits in two important ways. First, they automate energy efficiency—for example, by shutting off lights, devices, and appliances when they are not needed or by adjusting heating, ventilation, and air conditioning depending on the time of day. Second, they enable more advanced evaluation, measurement, and verification (EM&V, sometimes referred to as EM&V 2.0) of energy efficiency programs and incentives, improving their effectiveness and quantification, and enabling efficiency providers to be accurately compensated for providing energy efficiency benefits, including environmental benefits. ICTs enable networks that connect the electric grid from end to end, facilitating communications throughout the system. Example applications include advanced sensors and controls in buildings to detect and eliminate energy waste and advanced metering infrastructure (AMI) that enables automated response to electricity prices via settings (e.g., for thermostats) set by consumers. These technologies can improve the environmental performance, reliability, resilience, flexibility, and efficiency of the electricity system through real-time monitoring and control of grid systems.

Energy Efficiency: Environmental Benefits and Consumer Savings

End-use energy efficiency comprises a range of measures that provide end users the same services (such as light and air conditioning) with less energy. Energy efficiency has multiple benefits. All electric generation, transmission, and distribution has some impact on the environment. Energy efficiency avoids all of these environmental impacts. It emits no GHGs or air or water pollution. It has no impact on land use. It requires no siting, permitting, or decommissioning. Energy efficiency also saves consumers money, making it the most cost-effective decarbonization option. Energy efficiency programs and savings are discussed further in Chapter II (*Maximizing Economic Value and Consumer Equity)*.

DOE's Appliance and Equipment Standards Program[111] has served as one of the Nation's most effective policies for improving energy efficiency. The program implements minimum energy conservation standards for more than 60 products that consume about 90 percent of home energy use, 60 percent of commercial building energy use, and 30 percent of industrial energy use.[112] Since 2009, the United States has issued 40 new or updated standards to make appliances, buildings, and equipment more efficient. These standards are projected to reduce carbon emissions between 2009 and 2030 by over 2.5 billion metric tons, save consumers $557 billion on utility bills, and reduce primary energy consumption by 42 quadrillion British thermal units (quads).[q, 113]
This number is expected to grow to 3 billion metric tons with standards published through January 2017.[114] For example, in January 2016 DOE finalized efficiency standards for commercial air conditioning and heating equipment, which is projected to avoid 77 million metric tons of CO_2 by 2030.[115] Today, a typical household saves about $319 per year off its energy bills as a result of these standards, and as people replace their appliances with newer models, they can expect to save over $460 annually by 2030.[116] In addition to minimum efficiency standards for appliances, the Environmental Protection Agency (EPA) leads ENERGY STAR, a voluntary labeling program designed to help businesses and individuals save money and avoid pollution with energy-efficient products. ENERGY STAR labels appear on major appliances, office equipment, lighting, home electronics, new homes, and commercial and industrial buildings and plants. The ENERGY STAR program saved American consumers an estimated $24 billion in energy costs in 2012 alone.[117]

Buildings, which last for decades, account for 76 percent of electricity consumption and 40 percent of GHG emissions in the United States.[118] Recent analysis shows that in states consistently adopting the most recent versions of the model building energy codes, homeowners, building owners, and tenants are projected to save $126 billion on energy bills and reduce carbon emissions by over 841 million metric tons cumulatively

[q] These savings numbers are as of December 2016. Appliance and equipment standards continue to be issued and updated. Refer to the Appliance and Equipment Standards Program website for updated information: http://energy.gov/eere/buildings/appliance-and-equipment-standards-program.

between 2010 and 2040 if energy codes continue to be strengthened.[119] Many of the high-efficiency technologies, building envelope designs, and energy management practices that enable significant energy savings and GHG reductions beyond today's building codes have been demonstrated and are commercially available. While continued developments in building design and technology improvements in key building components and systems have led to large efficiency gains, there remains a large gap between the efficiency of the existing building stock and what is possible using technologies available today.[120] Policies or programs could help overcome market and behavioral barriers that are limiting deployment. Using existing technologies and building design and construction practices, builders are able to design homes that are up to 50 percent more efficient than typical new homes,[121, 122] and these can provide consumers with monthly energy savings up to $100.[r, 123, 124] The National Institute for Standards and Technology has completed a demonstration at its Net Zero Energy Residential Test Facility; total present value energy costs for a net-zero energy home were more than $40,000 lower than a new home built to the comparable minimum code.[125] Recent studies demonstrate that construction costs for net-zero energy buildings in the commercial sector are capable of falling within the same range as conventional new construction projects.[126, 127] It is worth noting that, when attempting to calculate the incremental construction cost of a net-zero energy building[s] compared to a conventional building, additional factors, such as continued operational savings, increased occupant comfort, and increased building value, should also be considered.

The industrial sector is responsible for approximately 26 percent of electricity-related CO_2 emissions.[128] Electricity productivity in the industrial sector (measured in kWh per dollar of output produced) has improved rapidly over the last 15 years,[t] and continued improvement will depend on persistent attention to efficiency. In regions where the emissions intensity of central electric generation is high, switching to CHP will have the biggest emissions impact. DOE estimates that there is technical potential for roughly 241 GW of CHP capacity in the United States, including industrial and commercial CHP as well as waste heat to power.[129] Since most of industrial CHP is fueled by natural gas,[130] however, either fuel-switching to decarbonized fuels or a transition away from CHP would be needed in the long term to more fully decarbonize the industrial sector.

Distributed Generation, Distributed Storage, and Demand Response

In recent years, there has been significant growth in DG, particularly rooftop solar PV, which has been fostered by lower installation and hardware costs and supportive policies, such as net metering and self-generation tariffs and RPS with set-asides or multipliers for DG. However, some states and utilities are adjusting their net metering policies as the distributed PV market grows. Net metering is a relatively simple policy, and as the distributed PV market has grown dramatically, many states are updating their incentive structures for distributed PV to more carefully account for changing electric system needs, transfers between ratepayer classes, and various benefit and cost streams. This is discussed in depth in Chapter II (*Maximizing Economic Value and Consumer Equity)*.

Small-scale distributed electricity storage is becoming more widely available and can contribute to a clean electricity system by facilitating increased penetration of variable wind and solar resources. It can also reduce peak load, improve electrical stability, and reduce power quality disturbances. Distributed storage is also covered in greater detail in Chapter II (*Maximizing Economic Value and Consumer Equity).*

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[r] EPA's ENERGY STAR Certified Homes are typically 15 percent to 30 percent more efficient than the average new home, yet they can provide monthly energy cost savings of about $27–$93 to consumers. DOE's Zero Energy Ready Homes are at least 40 percent to 50 percent more efficient than typical new homes, yet they can provide consumers with monthly energy savings of about $30–$100. See citations in the main text for details regarding these estimates (endnotes 124–125).

[s] Zero-energy buildings are high-performance commercial and residential buildings that are so energy efficient, a renewable energy system can offset most or all their annual energy consumption.

[t] Electricity productivity, measured as dollars of GDP produced per kWh, nearly doubled between 1990 and 2014, while industrial electricity sales were flat.

Like distributed storage, DR enables a cleaner grid by providing grid services with lower environmental impacts than other options for providing such services. If appropriately designed and resourced, DR enables utilities, grid operators, or other intermediaries to call for specific reductions in demand when needed; this could provide benefits in reducing peak load and supplying essential reliability services when increased VER are on the grid. At higher penetration levels of wind and solar (variable) energy resources, policies and regulations that enable greater penetration of DR in grid services markets are likely to become increasingly important to enable a cleaner grid.[131] AMI enables time-based rates and facilitates the integration of DG systems (e.g., solar), among other capabilities. More automated DR capabilities will enable greater flexibility of demand-side resources, improved integration of variable renewable energy resources, and easier valuation of their carbon emissions benefits, in addition to enhancing system integrity through greater area-wide knowledge. The most viable DR end uses for VER integration are electric water heaters and furnaces, air conditioners and lighting with advanced controls, agricultural irrigation, and motor/compressor drives with variable frequencies.[132]

Increased Electrification Is Essential for Decarbonization

Analyses that explore high levels of long-term GHG emissions reductions suggest that the increased electrification[u] of key end uses in transportation, buildings, and industry is one of three fundamental areas (in addition to decarbonizing electricity generation and adopting highly-efficient end uses) needed to achieve deep decarbonization.[133, 134] Multiple sectors of the economy have already begun to exhibit trends towards electrification. A continuing shift toward both decarbonization of the electric power system and electrification of end uses would help reduce GHG emissions economy-wide and provide a significant opportunity to avoid the GHG emissions associated with the direct use of fossil fuels without CCUS.[135] The level of GHG emissions reductions that can be achieved via electrification depends on a variety of factors, such as the carbon intensity of the electricity system; the efficiency of electricity generation, transmission, and distribution; energy efficiency improvements in end-use sectors; and the potential for fuel switching, which could include the use of hydrogen produced via electrolysis. Policies are needed to incentivize early technology adoption and to increase penetration of electrification in specific sectors, applications, and regions.

Electrification of Buildings

Analysis demonstrates that increasing electrification of building end uses could help the United States reach deep, economy-wide decarbonization.[136, 137, 138, 139, 140] The largest non-electric end uses for residential and commercial buildings are space heating and water heating. Electricity usage for space heating is currently increasing, and natural gas and other direct fuel usage are trending downward.[141] Advances in heat pump technology for both space heating and water heating have made heat pumps an economical and efficient choice. Heat pumps can be twice as efficient as electric resistance space heating. Currently, electrification of some end uses saves consumers money and/or saves energy in many parts of the country.[142, 143] Improving single-family detached homes with a package of fuel-switching efficiency upgrades[v] has the technical potential to save 450 trillion British thermal units (Btu) per year of primary energy nationally, or about 3 percent of

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[u] In the context of the QER, electrification includes both using electricity itself to power end-use applications as well as using electricity to make intermediate fuels, such as hydrogen.

[v] Upgrades considered in this package include (1) ductless heat pump replaces gas boiler (100% displacement); (2) ductless heat pump replaces oil boiler (100% displacement); (3) ductless heat pump replaces propane boiler (100% displacement); (4) variable speed heat pump replaces air conditioner and gas furnace; (5) variable speed heat pump replaces air conditioner and oil furnace; (6) variable speed heat pump replaces air conditioner and propane furnace; (7) heat pump water heater (80 gallon) replaces oil water heater; (8) heat pump water heater (80 gallon) replaces propane water heater.

total primary energy used for electricity in the residential sector in 2015.[w, x, 144] This energy savings and the corresponding emissions reduction potential varies widely by state and region as a result of fuel choice, technology, and climate differences. With current technologies, assuming a 50 percent and a 90 percent cleaner grid than today,[145] the technical potential of the same set of upgrades for carbon emission reductions is 80 million metric tons and 120 million metric tons of CO_2 per year, respectively.[146] The emissions savings would not be as significant with the current generation mix of the U.S. power sector. As technologies continue to improve and to come down in price, both the economic and technical potential will increase.

Electrification of Industry

The industrial sector, perhaps more than any other, is a sector in which technological innovation is needed for decarbonization; in addition, systematic economic electrification for shifting from direct fuel use is often technically more difficult and expensive for industry than for the residential and commercial sectors. Electrification is likely to be only partially viable for the industrial sector due to physical and economic reasons;[147] this would likely make the sector a high-value area for CCUS,[y] hydrogen, and biofuels to reduce carbon intensity.[z] Conventional boiler use and process heating are two industrial end uses with meaningful technical potential for electrification. Fuel-fired boilers can be replaced with electric boilers, and, depending on the industry, different electro-technologies are best suited to provide process heat. For example, electrolytic reduction, induction heating, resistance heating and melting, direct arc melting, and industrial process heat pumps can be used for process heating in the nonferrous metals (non-aluminum),[148] metal fabrication,[149] glass,[150] iron and steel,[151] food,[152] chemical,[153] and pulp and paper[154] industries, respectively.

Electrification of Transportation

Many studies conclude that significant CO_2 emissions reductions are needed from the transportation sector for deep decarbonization; this will require widespread electrification of, or use of another non-emitting fuel by, the U.S. vehicle fleet.[155, 156, 157] In recent years, there has been a sharp increase in electric light-duty vehicle sales and electric vehicle miles traveled, but total PEV sales account for less than 1 percent of all light-duty vehicle sales.[158] Projections for future adoption of these vehicles vary and may be influenced positively by smart mobility trends, such as connected and automated vehicles and ride sharing. Electrification technologies are also being introduced into other segments of the transportation sector, such as larger vehicle classes and ground operations at ports and airports.

When buying a new vehicle, however, one of the most important criteria for purchasers is the upfront vehicle price;[159] future fuel savings tend to be under-valued.[160, 161] Currently, the average price of new gasoline-powered cars is similar to that of comparable new PEVs with incentives.[162] In fact, with incentives, for some purchasers, the total cost of ownership over the lifetime of a vehicle can actually be lower for PEVs.[163, 164, 165] Incentives are still, however, important for deployment of PEVs. While battery costs have come down and are projected to continue to decrease with continued RD&D,[166] scaling up production alone will not be sufficient to lower the cost of PEVs to make them comparable to internal combustion engines without incentives and further technology cost reductions.[167]

[w] The current economic potential (net present value >0) to save primary energy with this package of measures is lower, but it is still significant at 252 trillion Btu per year.

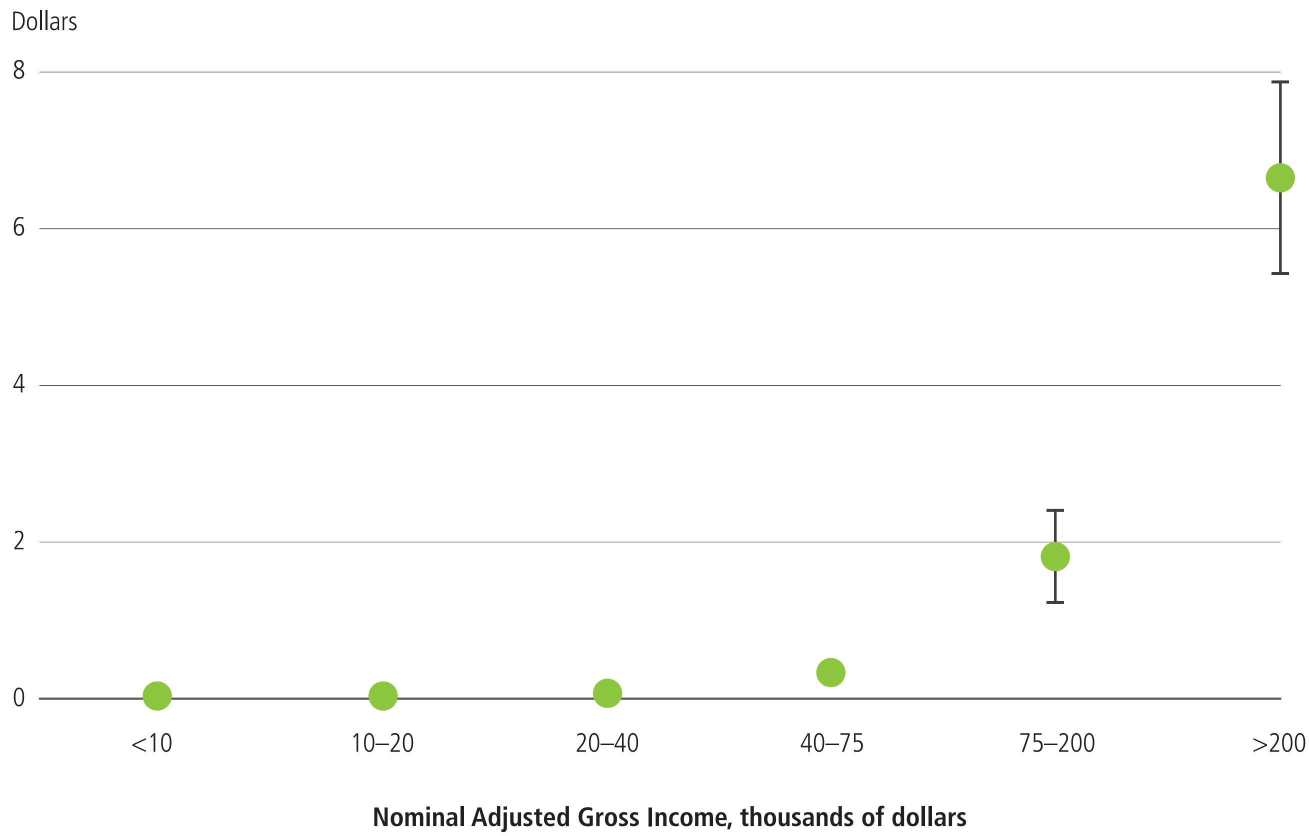
[x] This accounts for the conversion losses of electricity generation and the transmission and distribution (T&D) line losses compared to direct fuel usage (e.g., natural gas, oil, and propane).

[y] Many industrial processes produce relatively pure streams of CO_2, making CCUS an attractive method for decarbonizing portions of the industrial sector. Industrial facilities represent a low-cost pathway for stimulating CCUS deployment, as capture from high-purity sources provides valuable early permitting, infrastructure deployment, and market opportunities; this, in turn, will lower the cost of capturing CO_2 from future industrial and power sector projects.

[z] A significant fraction of energy consumption in industry goes to feedstock use and cannot be decarbonized through electrification. Several industrial processes have the potential to substitute materials for lower GHG options.

A related issue: A recent study found that the current Federal tax credits for plug-in and alternative motor vehicles are being disproportionately utilized by vehicle owners in higher income brackets, as 90 percent of the Qualified Plug-In Electric Drive Motor Vehicle Credits went to buyers in the top income quintile (Figure 3-12).[168] The state of California recently decided to increase the amount of the state's clean vehicle rebate for lower income purchasers and at the same time implement an upper income cap on eligibility.[169] Analysis of the California rebate, prior to the recent change, found that a progressive rebate system with an income cap would be less expensive but result in approximately the same number of PEVs sold.[170]

Figure 3-12. Qualified Plug-In Electric Drive Motor Vehicle Credit, 2009–2012[171]



The relationship between average credit per tax return per adjusted gross income category demonstrates that, historically, high earners are the group that derives the most financial benefits from the Qualified Plug-In Electric Drive Motor Vehicle Credit.

In the medium- and heavy-duty vehicle market, there are some commercially available PEVs, including battery electric transit, school, and shuttle buses, as well as other medium-duty vehicles, primarily delivery vehicles.[172] Although medium- and heavy-duty PEV purchase costs are higher than conventional vehicles, these PEVs have reduced operating and maintenance costs,[173] which may make them attractive to fleet operators if they can finance the initial purchase of the vehicle.

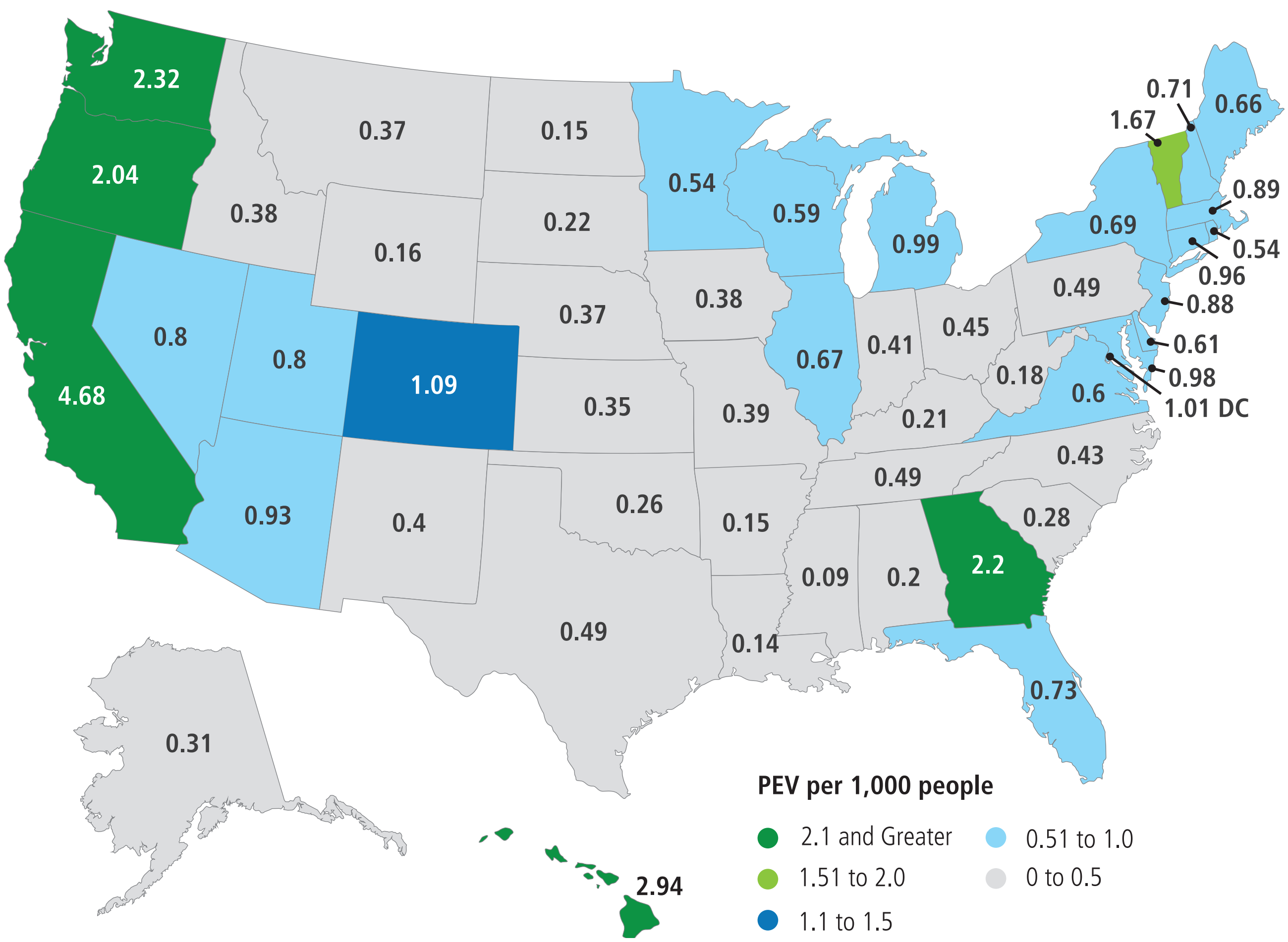
The availability and type of electric vehicle charging stations is another issue. Chargers vary dramatically in price and the amount of time it takes to charge a vehicle.[aa, 174] The United States currently has more than 40,000 publicly accessible outlets at more than 14,000 charging stations (excluding private stations),[175] but continued

[aa] For example, Level 1 chargers take at least 33 hours to charge 200 miles and typically $300–$1,500 dollars to install. Direct current (DC) fast chargers take about 2 hours to charge 200 miles and cost $45,000, plus $23,000 on average for installation.

increases in charging availability—especially deployment of advanced fast-charging stations—would support and incentivize widespread PEV adoption.[176] Research shows that available public fast charging reduces range anxiety and increases electric vehicle miles traveled.[177] Developing a network of chargers along highways to include direct current (DC) fast chargers, and perhaps even 350-kW extreme fast charging, could enable PEV owners to use these vehicles for distance driving, as they might otherwise use a conventional vehicle.[178] Also, when workplace charging is available, employees are six times more likely to own a PEV, and those employees charge their vehicles at work.[179, 180]

There is a range of incentives and programs to expand PEV infrastructure. More than 20 state and Federal policies exist to incentivize the installation of PEV charging infrastructure (Figure 3-13 shows PEV registrations by state).[181] Also, in November 2016, the Federal Highway Administration announced 55 routes that will serve as a basis for a national network of alternative fuel and electric charging corridors spanning 35 states and nearly 85,000 miles.[182] Those corridors are designated as "sign-ready," meaning that routes where alternative fuel and charging stations are currently in operation will be eligible to feature new signs alerting drivers where they can find these stations.[183]

Figure 3-13. PEV Registrations per 1,000 People by State, 2015[184]



The concentration of PEV registrations varies by state, with the highest concentrations in California, Washington, Georgia, and Oregon.

In addition, California has unique authority under the Clean Air Act (CAA) to issue vehicle emission standards that are stricter than those issued by the Federal Government, and other states can adopt California's standards in their entirety. The California Air Resources Board adopted a zero-emission vehicle (ZEV) rule as part of the state's 1990 Low Emission Vehicle Program. Nine additional states have chosen to adopt California's ZEV rule to date: Connecticut, Maine, Maryland, Massachusetts, New Jersey, New York, Oregon, Rhode Island, and Vermont. It is difficult to predict the future ZEV market penetration, but about 15.4 percent of new vehicles sold in participating states will be required to be ZEVs by 2025. By 2025, California needs to reach an estimated 265,000 ZEV sales per year—an increase of 250 percent over the next decade.[185]

Transit incentives are also available. For example, through the Low or No Emission Vehicle Deployment Program, the Federal Transit Administration provides funding to state and local governments for the purchase or lease of qualifying low- or no-emissions buses, including all-electric buses and related equipment and upgrades to facilities to accommodate new buses.[186] Qualifying airports can also seek Federal Government support for electrification of equipment and vehicles. The Federal Aviation Administration's Voluntary Airport Low Emissions and Zero Emission Vehicle Programs provide financial support for the purchase of electric equipment and vehicles.[187, 188]

Analytical Tools: Converting Data to Information Is Key to a Cleaner Electricity System

Real-time data at fine granularity and a suite of analytical tools and models will constitute the backbone of a modern, cleaner electricity system that integrates variable renewables and energy-saving technology. Other data and analysis tools will also be needed to inform decision making as governments, utilities, and consumers search for ways to maximize the benefits of new clean electricity technologies. There are several concerns related to the proliferation of real-time and other data. Of paramount importance are data privacy and security. Ensuring the completeness, quality, harmonization, and accessibility of data to decision makers is also very important.

Data needs and opportunities are particularly strong in electricity end-use consumption and energy efficiency. First, end-use surveys have gaps, such as a lack of water sector data, and the end-use surveys have not kept up with shifting demand coming from the proliferation of new electronic appliances. Second, planners will need more granular data on energy consumption and energy efficiency to address grid operation needs due to new variable resources and increasing consumer energy management. Third, the increased ability to measure and monitor end-use data at finer scales brought by AMI and ICTs provides an opportunity to target the specific energy efficiency measures most capable of reducing peak demand for a given location and season.

Updates to measurement and verification protocols, which vary by technology, can help drive the transition to a cleaner electricity system. The wealth of data being generated by AMI is enabling "evaluation, measurement, and verification 2.0," as discussed in Chapter II (*Maximizing Economic Value and Consumer Equity*).[ab] In California, some consumers now receive data on what type of generators are currently providing the electricity at their home or business. Based on the generation mix, the consumer can decide how much electricity to use in real time using a smart device. Established forms for DR, such as direct load control, have well-understood and accepted methods for measuring the amount of DR available and deployed and for verifying that the

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[ab] Updates to measurement and verification protocols, which vary by technology, can help drive the transition to a cleaner electricity system. The wealth of data being generated by AMI, along with improved analytical tools, are enabling advanced evaluation, measurement, and verification methods commonly referred to as "EM&V 2.0." See EPSA Analysis: Lisa C. Schwartz, Max Wei, William Morrow, Jeff Deason, Steven R. Schiller, Greg Leventis, Sarah Smith, et al., *Electricity End Uses, Energy Efficiency, and Distributed Energy Resources Baseline* (Berkeley, CA: Lawrence Berkeley National Laboratory, January 2017), https://energy.gov/epsa/downloads/electricity-end-uses-energy-efficiency-and-distributed-energy-resources-baseline.

intended and actual amount deployed are the same.[ac] Emerging forms of DR, such as aggregating reductions from residential critical peak pricing programs, are areas where continually improving measurement and verification will assist in the transition to a cleaner electricity system.

Improving data and analysis tools can help decision makers utilize energy efficiency measures for minimizing costs and ensuring reliability, including providing technical assistance on tools that enable the full consideration of energy efficiency as a resource. Analysis is needed at the appropriate level of granularity to inform understanding of system dynamics and behavior, including the effects of changing environmental conditions and resource availability, environmental impacts, and interactions between multiple infrastructures, such as electricity and water. For example, further analytical tools are needed at multiple spatial and temporal scales to better frame system-level tradeoffs related to resilience, economics, environmental impacts, and other factors that can inform design and policy decisions, such as those related to the integration of electricity and water systems.

For both national policy formulation and state integrated resource planning, there is often a need to make a determination on the level of savings that is cost effective from energy efficiency and other DER (i.e., DR and DG). Currently, there is an incomplete patchwork of different energy efficiency potential studies (as well as studies that analyze the possible savings for other distributed resources) at the utility or state level that use a variety of different methodologies. These studies, which typically consider only energy efficiency, do not take into account the opportunity to integrate energy efficiency investments with other consumer options, such as DR, DG, and onsite storage—technologies to which consumers have growing access. A national demand-side resources potential assessment with sufficient geographical resolution could be used to more effectively integrate DER into state and national energy policy. Due to the increasing availability of multiple demand-side resources, any potential assessment that considers only one of these resources will overestimate the savings from one approach while underestimating the impacts of an integrated approach. For example, a customer considering energy efficiency investments will have a different bill savings if they are already participating in a utility DR program for a given end use, like water heating or air conditioning.

In addition, enhancements to existing electricity sector models will be required as climate change and other challenges affect the electricity system. The history of computer models in the electricity sector is extensive. The sector is highly dependent on modeling for planning, investment, regulation, and system operations. Energy efficiency supply curves are not commonly used in electricity sector modeling because there are not sufficiently robust and granular (location- and technology-specific) data on the potential of energy efficiency measures for the entire Nation—something a national potential assessment could provide. For example, capacity expansion models, such as the National Energy Modeling System (NEMS), are widely used for policy formulation and resource planning. NEMS would particularly benefit from improvements in characterizing electricity end use, energy efficiency, DG, and storage.

Finally, enhanced models examining environmental impacts, resource base, and competing uses would be valuable in informing siting, permitting, and operational practices for generation. It would be useful for hydropower project models to illuminate environmental and land-use impacts and co-benefits. For geothermal energy, it would be valuable to characterize a substantial portion of the geothermal resource base, which could help to reduce siting and prospecting costs.[189] For CCUS projects, models can improve standardized site characterization that informs the determination of areas with the appropriate storage geology.

[ac] A separate issue is verifying that the amount of DR that a utility or third party commits to provide is actually provided when called upon.

Electricity System Assets, Operations, and Planning

There are many technical, market, and policy challenges related to how electricity sector investment decisions and operations, Federal and state policy and regulations, and system and policy planning interact with efforts to shift to a low-carbon electricity system. To realize a cleaner electricity system, stakeholders will need to consider all aspects and integration of an end-to-end supply chain, from generation to end use.

Electricity infrastructure owners' choices on resilience, expansion, and modernization will have implications for achieving the Nation's environmental goals, and vice versa. Chapter IV (*Ensuring Electricity System Reliability, Security, and Resilience*) discusses the need for and interaction between improvements in the electricity system's clean, resilient, and flexible characteristics. The same chapter adds that probabilistic planning is a robust method of assessing what infrastructure, including renewable generation, should be built for reliability purposes.

Integrating Energy and Capacity Markets with Clean Policies

In the summer of 2016, the New England Power Pool (NEPOOL) began a stakeholder process designed to explore whether the various environmental policies across member states could be integrated into the regional energy and capacity markets operated by Independent System Operator–New England. Known as the Integrating Markets and Public Policy initiative, it has the potential to set an important precedent for how clean policies can be integrated into existing regional markets.

"Our goal at NEPOOL and for the region is to create a competitive market signal to get the states what they need so they don't have to act on their own. If we're successful, the markets on their own will find the most cost-effective means in meeting those state objectives."

– NEPOOL Chairman Joel S. Gordon[ad]

Following the release of an initial problem statement and guidelines in May 2016, stakeholders were invited to propose ideas at the group's first meeting in August. Proposals offered a wide range of solutions: from a carbon price adder, to a separate "clean-only" auction process called a "Forward Clean Energy Market," to strengthening the Regional Greenhouse Gas Initiative. Some proposals recommended price adjustments in the energy markets, while others offered modifications to the capacity markets.

[ad] William Opalka, "Q&A: NEPOOL Chair on Redesigning Market Rules for Low-Carbon Future," *RTO Insider*, September 5, 2016, 9, https://www.rtoinsider.com/nepool-market-rules-low-carbon-future-31249/.

Grid architecture alternatives are also important to consider for achieving a clean electricity future. Chapter IV (*Ensuring Electricity System Reliability, Security, and Resilience*) discusses architectural and operational alternatives to increase resilience. All of those alternatives, which decrease system response times and increase flexibility, would have important co-benefits in integrating renewable generation.

Efforts to improve near-term forecasting and granular grid visualization are already underway and have clear benefits for clean generation, as are efforts to enhance situational awareness and operational visibility for reliability, security, and resilience reasons. All of these methods would also lower the economic cost of renewable integration and are discussed in detail in Chapter IV (*Ensuring Electricity System Reliability, Security, and Resilience*).

Power market dynamics also affect clean power goals, and vice versa. Lower energy prices, which are partly due to low-cost natural gas and incentivized zero-marginal-cost resources, are reducing the economic viability of other desired clean resources, including nuclear energy.

Many of the planning-related challenges jurisdictional authorities face arise from the recent trend in technology advancement—and, specifically, the increase in new technologies and mechanisms focused at the end-use sector—behind the meter. This trend has caused a shift in the underlying assumptions upon which most planning requirements are established. There are many areas where Federal policy could facilitate the full consideration of the cost and benefits of energy efficiency, other demand-side management resources, and clean energy in planning processes, including improving data, advancing tools and representation in models, and providing technical assistance on tools that enable the full consideration of these clean resources in planning. The Federal Government is providing expanded technical assistance on methods of fully accounting for energy efficiency, other demand-side management resources, and clean energy in resource planning conducted by governments and utilities that could help break down institutional barriers to considering energy efficiency as a resource.

Other planning drivers exist as well. For example, evolving environmental requirements at the Federal level (e.g., the recently promulgated "Clean Power Plan" [CPP]) and clean energy goals at the state level (e.g., RPS) encourage jurisdictional authorities at the state level and across states to coordinate to ensure requirements are met at low cost.

As discussed in Chapter II (*Maximizing Economic Value and Consumer Equity*), ratemaking[ae] is one of the public policy instruments that states use to incentivize and regulate the electricity sector. It is important that the environmental benefits of clean electricity are appropriately valued. To realize the full potential of increased DER, clean energy generation, and more sophisticated grid technologies (such as smart meters and supervisory control and data acquisition systems), regulators "will need to utilize more advanced rate designs than they have in the past."[190] As DER become more prevalent in the United States, for example, the traditional ratemaking models may no longer provide utilities with adequate means to properly recover the true costs of electricity generation, transmission, and distribution.[191] Public utility commissions have already begun to address this challenge in a wide variety of ways, reflecting states' different policy objectives and generation portfolios. Many states have instituted decoupling or lost-revenue adjustment mechanisms, which break the link between the amount of energy a utility sells and the revenue that it collects, increasing the utility's acceptance of energy efficiency programs. More recently, states have also begun to examine how to value the costs and benefits of DER. "Value of solar" tariffs, for example, intend to "associate a quantifiable benefit with each kWh of distributed solar exported to the grid"[192] and translate this benefit into a dollar per kWh rate, giving utilities and regulators a pricing tool that reflects the value of this electricity better than retail or wholesale rates. As the role of clean energy in ratemaking continues to evolve, the Federal Government and states can cooperate to estimate the value attributed to electricity products and services, facilitate data and information exchange to guide ratemaking and rate design, and share lessons learned.

Multiple Paths Forward for CO_2 Emissions Reductions from the Electricity System

As noted, the CO_2 intensity of the electricity system is expected to continue to decrease due to several factors, including fuel switching, technology innovation, and clean energy policies. The Federal Government has set economy-wide emissions reduction targets of 17 percent below the 2005 level by 2020, and 26 to 28 percent below the 2005 level by 2025.[193] These 2020 and 2025 targets were formally submitted to the United Nations Framework Convention on Climate Change in January 2010 and March 2015, respectively, and

[ae] For a description of the rate design process, see the Appendix (*Electricity System Overview*).

they are consistent with a straight-line emission reduction pathway from 2020 to economy-wide emission reductions of 80 percent or more by 2050.[194] An 80 percent economy-wide reduction in the United States, given commensurate reductions elsewhere, could help limit the increase in global mean surface temperature to 2 degrees Celsius above preindustrial levels and mitigate the worst impacts of climate change.[195] In order to achieve such deep levels of emissions reductions, it is likely that the electricity sector will need to provide greater and more immediate GHG emissions reductions than other sectors because it includes the most cost-effective options for reducing GHG emissions.

The President's "Climate Action Plan,"[196] the current U.S. strategy for addressing climate change, was formulated to mitigate global climate change and reduce U.S. GHG emissions. The CPP, which was finalized by EPA in August 2015, is an example of a policy that, when implemented, will further the goals of the President's "Climate Action Plan" by continuing the trend of decreasing CO_2 intensity.[af] Under Section 111(d) of the CAA, the CPP regulates carbon emissions from existing power plants and requires states to adopt plans to limit emissions from existing fossil fuel–fired power plants. EPA projects that, by 2030, the CPP will help cut carbon emissions from the power sector by 32 percent from 2005 levels.[197]

Tax credits for clean energy have also contributed to reduced CO_2 emissions and are projected to continue to help reduce electricity sector emissions in the future.[198] NREL analysis projects a 50-GW increase in cumulative installed renewable energy capacity by 2020 due to the Federal tax credit extensions.[199]

A Record of Environmental Policy Successes

The successes of existing environmental policy are instructive for meeting future national environmental goals and objectives. The modern framework for improving air quality in the United States was established in 1970 with the creation of EPA and the passage of the 1970 CAA, which was subsequently amended in 1977 and 1990. While the electricity system has historically been a major source of air pollution, since the passage of the CAA, emissions of air pollutants (including sulfur dioxide [SO_2] and nitrogen oxides [NO_x]) have fallen dramatically below 1970 emissions levels. Between 1970 and 2014, aggregate emissions of common air pollutants from the electric power sector dropped 74 percent, even as electricity generation grew by 167 percent and the U.S. GDP grew by 238 percent.[200, 201, 202]

The health benefits of reducing emissions of air pollutants from power plants and other sources include avoided premature deaths, avoided heart attacks, fewer cases of respiratory problems (such as acute bronchitis and asthma attacks), and avoided hospital admissions.[203, 204, 205] Air-quality improvements from the Acid Rain Program, part of the CAA amendments of 1990, were estimated to yield health benefits of around $50 billion annually in 2010, compared to compliance costs that are on the order of $0.5 billion.[206, 207, 208, 209, 210] More recently, the 2012 Mercury and Air Toxics Standards, which established emissions limits for power plants for mercury, acid gases, and heavy metals, are projected to prevent up to 11,000 premature deaths, 4,700 heart attacks, and 130,000 asthma attacks every year.[211]

The economic benefits of clean air policies are also well-documented. A study looked at the impacts of the CAA amendments of 1990 and showed that—looking forward to 2020 in cumulative, net-present-value terms—there will be $2 trillion in benefits compared to $65 billion in costs, a benefit-cost ratio of over 30 to 1.[212]

[af] On February 9, 2016, the Supreme Court stayed implementation of the CPP pending judicial review. The Court's decision was not on the merits of the rule. EPA firmly believes the CPP will be upheld when the merits are considered because the rule rests on strong scientific and legal foundations. EPA will continue to provide tools and support for the states that choose to continue to work to cut carbon pollution from power plants and seek the Agency's guidance and assistance.

In addition, the United States is the world's largest producer and consumer of environmental technologies.[ag] In 2015, the U.S. environmental technologies and services industry employed 1.6 million people, had revenues of $320.4 billion, and exported $51.2 billion worth of goods and services.[213, 214] U.S. industry revenues for air-pollution control alone totaled $19.6 billion, including equipment, instruments, and attendant services, while U.S. revenues for air-quality monitoring instruments and information systems totaled $1.3 billion.[215] This experience shows that the United States has consistently been able to manage environmental pollution with benefits far outweighing the costs, all while continuing to grow the economy and support millions of jobs.

A Record of Clean Energy Technology Successes

The United States has historically been a global innovation leader, and the U.S. Government is one of the largest funders of electricity sector RD&D in the world. The Federal Government's long-standing electricity sector RD&D investments, in concert with supporting policies, have made significant impacts on the Nation's electric infrastructure for decades through the present day.

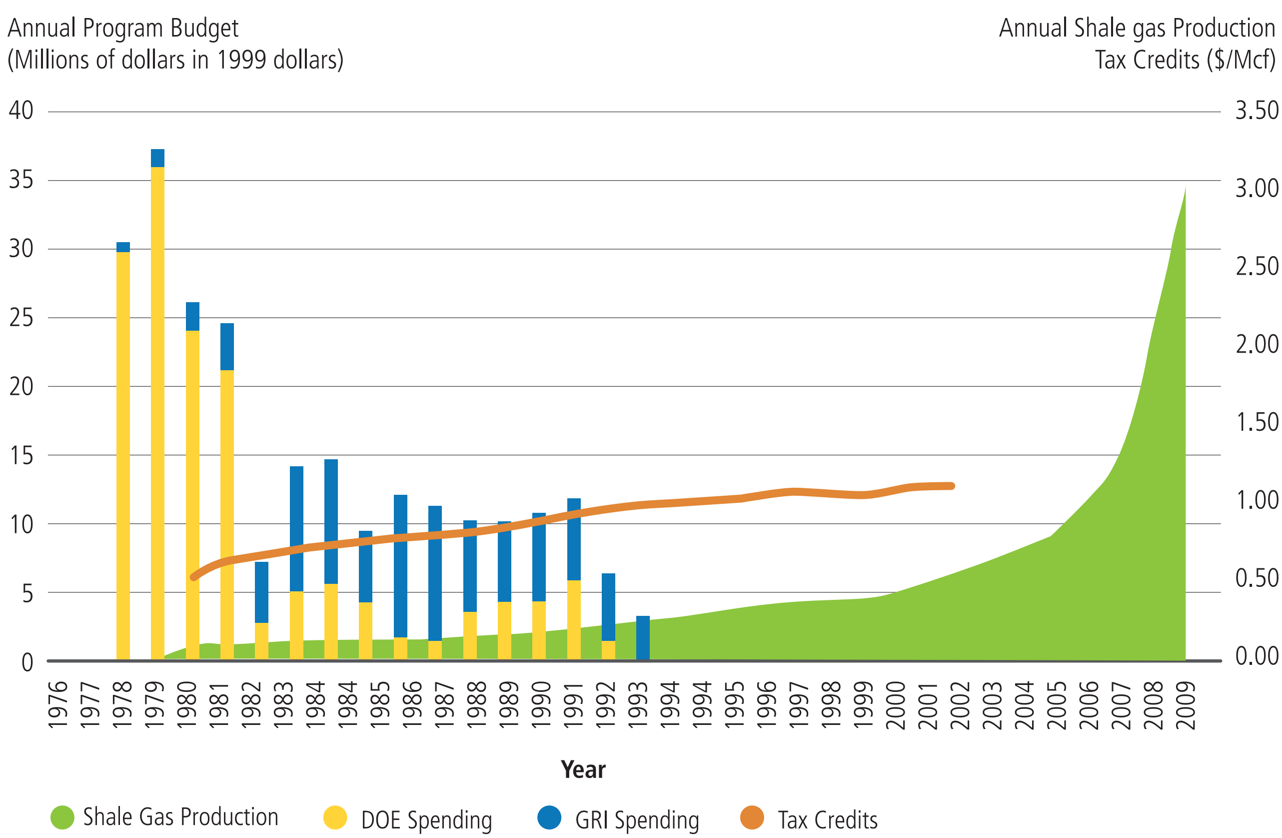
[ag] Environmental technologies are devices that reduce the environmental impact of natural resources. Examples of environmental technologies that have contributed to the United States' success in reducing air pollution include activated carbon injection, flue-gas desulfurization, selective catalytic reduction, and dry-sorbent injection.

Shale Gas Research, Development, and Demonstration (RD&D) and Time-Limited Tax Credit

Early Federal shale gas RD&D funding, primarily for basin characterization and key drilling technologies, combined with a public-private partnership and a time-limited Federal Production Tax Credit, resulted in a sharp increase of shale gas in the mid-2000s (Figure 3-14). Today, shale gas is around 60 percent of total U.S. natural gas production. The interplay of early Department of Energy funding, industry-matched Gas Research Institute applied RD&D, and synergistic policy incentives enabled production from shales previously considered uneconomic. The switch from coal and petroleum power generation to less-carbon-intensive and more efficient combined-cycle natural gas generation resulted in over 1.2 billion metric tons of carbon dioxide emissions reductions from 2005 to 2014.[ah]

[ah] Massachusetts Institute of Technology, *The Future of Natural Gas* (Cambridge, MA: Massachusetts Institute of Technology, 2011), 29, 163.

Figure 3-14. Steady RD&D Funding and Time-Limited Tax Credit Led to Increase in U.S. Shale Gas Production, 1976–2009.[216]



Federal funding, time-limited tax credits, and Gas Research Institute (GRI) funding led to a significant increase in gas production, starting in the mid-2000s. Abbreviations: 1,000 cubic feet of natural gas (Mcf).

Light-Emitting Diodes (LEDs) Research, Development, and Demonstration (RD&D) and Lighting Efficiency Standards

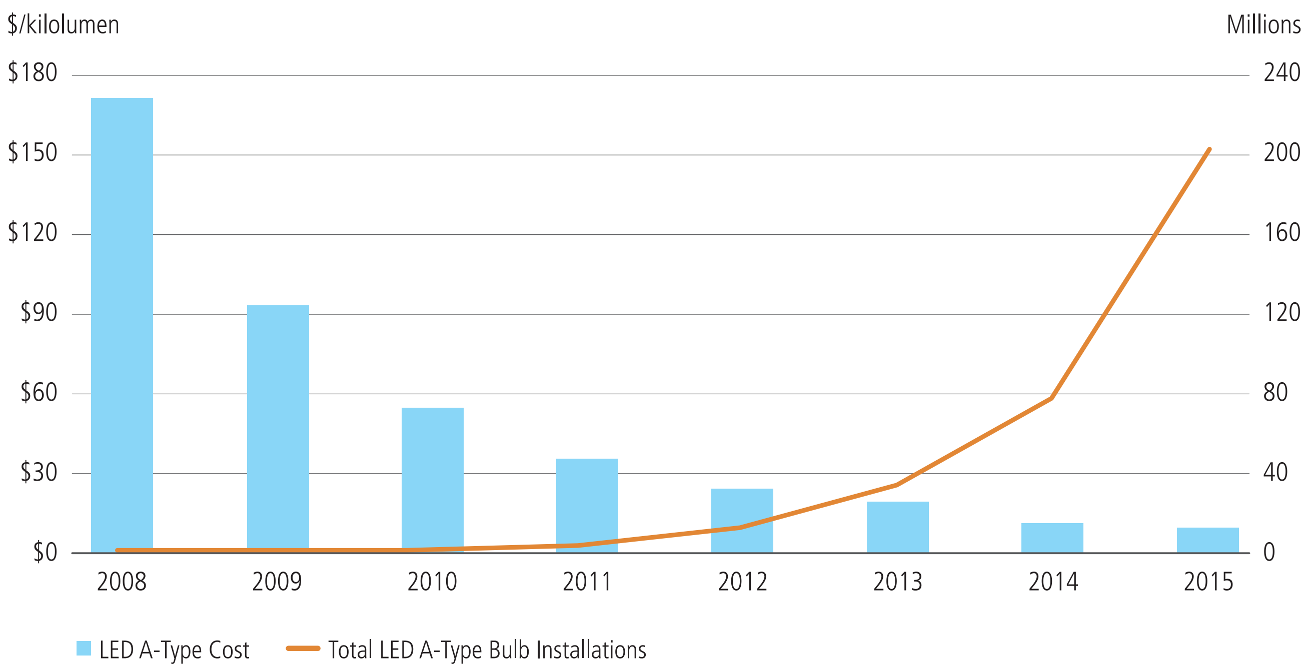
Federal and private-sector RD&D investments directly brought down LED costs, improved efficiency and performance, and fostered domestic manufacturing of LED lighting components and products.[ai] Since the Department of Energy (DOE) began funding solid-state lighting research projects in 2000, large and small businesses, universities, and National Laboratories that received DOE funds have applied for more than 260 patents and developed more than 220 commercially available products in this technology area, including lighting products, power supplies, materials, and manufacturing tools.[aj, ak] In 2007, Federal legislation set minimum operating life and energy efficiency standards for a majority of light sources used by the public and relied heavily on technology innovation for manufacturers to meet those standards. The same legislation also mandated an efficient lighting competition, the "L Prize," that provided cash prizes and Federal Government purchase contracts for winning products. The combination of national lighting standards and lighting technology innovation investments and incentives has contributed to a rapid decline in LED product costs and a corresponding increase in LED sales (Figure 3-15).

[ai] Department of Energy (DOE), *Revolution Now: The Future Arrives for Five Clean Energy Technologies – 2016 Update* (Washington, DC: DOE, 2016), 8, https://energy.gov/sites/prod/files/2016/09/f33/Revolutiona%CC%82%E2%82%ACNow%202016%20Report_2.pdf.

[aj] Department of Energy (DOE), *Solid-State Lighting Patents Resulting from DOE-Funded Projects* (DOE, Building Technologies Office, January 2016), DOE/EE-1325, 1, https://energy.gov/sites/prod/files/2016/01/f28/patents_factsheet_jan2016.pdf.

[ak] Department of Energy (DOE), *Solid-State Lighting Commercial Product Development Resulting from DOE-Funded Projects* (DOE, Building Technologies Office, June 2015), DOE/EE-1234, 1–4, https://energy.gov/sites/prod/files/2015/07/f24/comm-product-factsheet_jun2015.pdf.

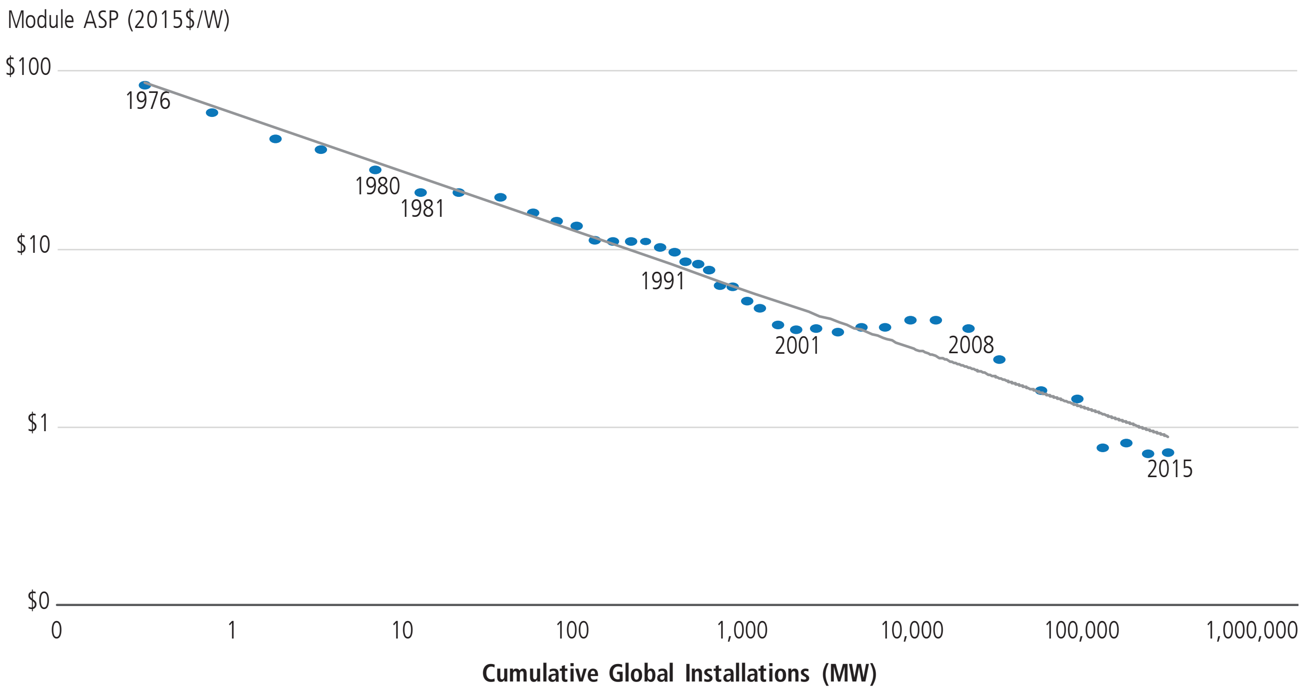
Figure 3-15. LED Costs and Installations, 2008–2015[217]



Light-emitting diode (LED) bulbs now account for 6 percent of all installed A-type bulbs, which are common in household applications. This growth has been enabled by a 94 percent reduction in cost since 2008. In 1 year, total installations of common home LED bulbs more than doubled from 77 million to 202 million—a particularly rapid growth considering there used to be fewer than 400,000 installations as recently as 2009. Across all LED product types, LED installations prevented 13.8 million metric tons of CO_2 emissions and saved $2.8 billion in energy costs in 2015 alone.

Solar PVs (Figure 3-16), light-emitting diodes (LEDs), and shale gas development are among many other electricity-related technologies that demonstrate the instrumental role of Federal investment in early-stage research and development (R&D). As technologies mature, these case studies also show the need for both innovation and policy, and illustrate the synergistic interactions among complementary innovation and policy efforts. For example, innovation investments reduce the cost of policies and incentives and allow decision makers in both government and the private sector to consider options that would otherwise not be available. Increased deployment levels due to policies and incentives also increase economies of scale and further reduce manufacturing costs and technical risks.

Figure 3-16. Long-Term Solar PV Cost Decline and Global Deployment Growth, 1976–2015[218, 219, 220, 221, 222]



This experience curve displays the relationship, in logarithmic form, between the average selling price (ASP) of a PV module and the cumulative global shipments of PV modules. Average module prices have dropped by about a factor of 100 since 1976 to under $1/watt (W), while cumulative module shipments have increased from less than 1 MW to over 200 GW. For every doubling of cumulative PV shipments, there is, on average, a corresponding reduction of about 20 percent in PV module price.

Market-Based Carbon Policies

A transparent, market-based policy to price carbon emissions has been documented as the most cost-effective way to reduce GHG emissions.[223] Market-based incentives such as a carbon charge or price encourage actors in the economy, including consumers and utilities, to internalize the costs to society of emitting GHGs. In addition, a transparent, market-based policy to price carbon emissions drives the most cost-effective emissions reductions first, which achieves the goal of reducing CO_2 emissions at the lowest cost. Long-term carbon pricing policies also reduce uncertainty and send clear market signals that encourage innovators to develop new and improved clean energy technologies.

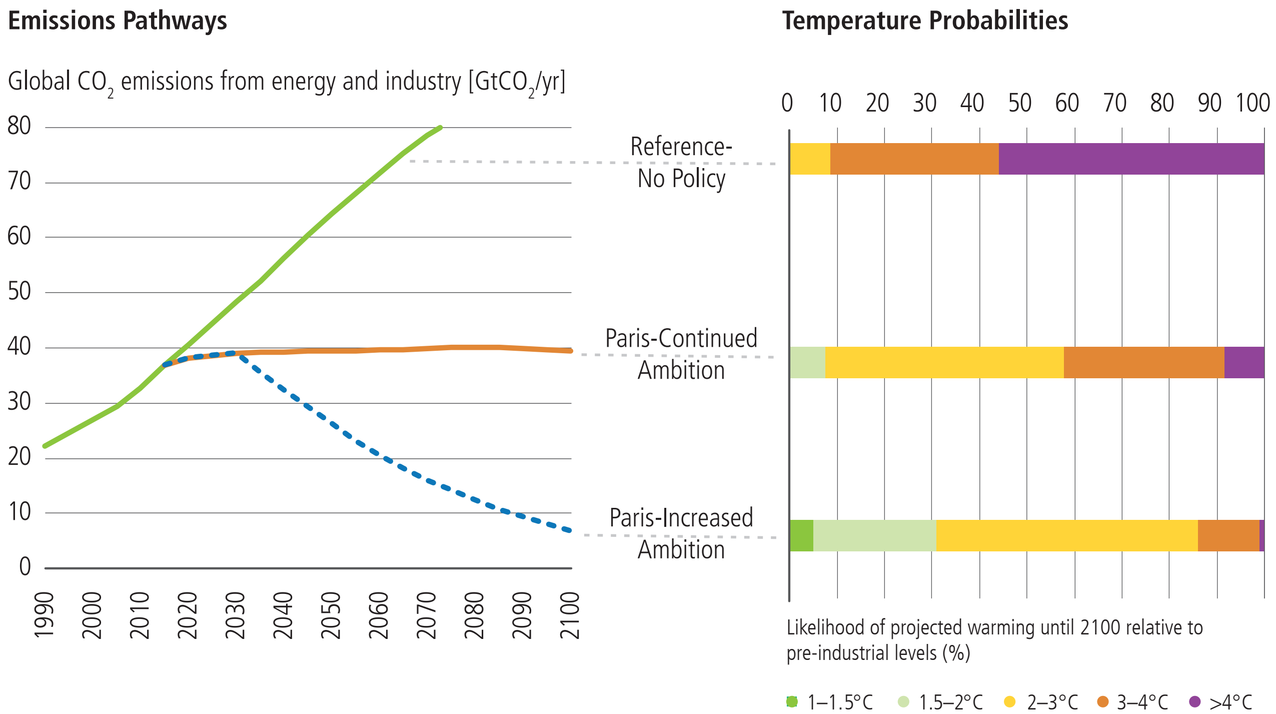
Ten U.S. states are currently implementing market-based carbon pricing policies. For example, nine states in the Northeast and Mid-Atlantic are implementing the Regional Greenhouse Gas Initiative, which is a multi-state GHG cap-and-trade program.[224] Investments spurred by the Regional Greenhouse Gas Initiative are estimated "to save 76.1 million Btu of fossil fuels and 20.6 million MWh of electricity" over the lifetime of these investments.[225] California is implementing Assembly Bill 32, the California Global Warming Solutions Act, which was enacted in 2006. Assembly Bill 32 requires the reduction of statewide GHG emissions to 1990 levels by 2020. One component of California's program is a statewide GHG cap-and-trade program.[226] California's program is linked to Quebec's program, allowing for cross-border GHG emissions trading. Carbon emissions are falling faster than anticipated, and the demand for emission allowances has been decreasing.[227, 228] Although the United States does have a Federal cap-and-trade program for SO_2 emissions, there is no market-based policy for GHGs at the Federal level.[al]

Addressing Climate Change, Growing the Economy through Innovation

Climate change is one of the world's major challenges. The 17 warmest years on record have occurred in the last 18 years.[229] 2015 was the warmest year on record, and based on the latest data, 2016 is expected to set a new record.[230, 231] Global temperatures have already warmed 0.85 degrees Celsius from preindustrial times.[232]

The successes of the CAA offer lessons about our ability to simultaneously address environmental concerns and grow the economy. Mitigating climate change is, however, intrinsically more complicated because it is a global problem that affects all sectors of the economy.

Figure 3-17. Global CO_2 Emissions (left) and Probabilistic Temperature Outcomes (right) of United Nations Framework Convention on Climate Change's 21st Session of the Conference of the Parties in Paris in December 2015, 1990–2100[233]



Implementing the 21st Conference of Parties pledges could significantly reduce the chances of a level of warming greater than 4 degrees Celsius by 2100 (as seen under the Paris-Continued Ambition scenario). However, to decrease the likelihood of projected warming above 2 degrees Celsius, additional actions are required (as seen under the Paris-Increased Ambition scenario). Emissions are measured in gigatonnes (Gt) of CO_2.

[al] The CPP provides states with flexibility to choose different pathways (some of which are market-based) to comply. If all states choose a market-based policy under the CPP, a Federal market is not necessarily created.

The Paris Agreement, adopted in December 2015, explicitly acknowledged that climate change warranted a global response, with more than 190 countries agreeing to make national commitments to substantially reduce their GHG emissions.[234] In an effort to reduce the risks and effects of climate change, the Paris Agreement sets a goal to keep global average temperature rise to no more than 2 degrees Celsius above preindustrial levels and to pursue efforts to limit the temperature increase to 1.5 degrees Celsius.[235] Reports issued by the Intergovernmental Panel on Climate Change suggest that in order to limit warming to 2 degrees Celsius to mitigate the worst impacts of climate change, developed countries must achieve deep decarbonization by reducing their emissions by 80 to 95 percent relative to a 1990 baseline.[236, 237] Pursuant to the Paris Agreement, all countries must commit to submitting successive nationally determined contributions (NDCs) every 5 years that "represent a progression" beyond their current NDC and which outline what each country plans to do to address climate change.[238] The emissions under the current NDCs (the orange line in Figure 3-17) are too high to limit warming to 2 degrees Celsius. Additional actions to reduce emissions are needed.

The U.S. commitment in Paris affirmed that the United States is prepared to pursue further reductions beyond the previously announced "economy-wide target of reducing its GHG emissions by 26 percent to 28 percent below its 2005 level in 2025 and to make best efforts to reduce its emissions by 28 percent."[239] The United States formally joined the Paris Agreement on September 3, 2016,[240] and is strongly committed to taking action and global leadership to address climate change.[241]

Projecting out to the mid-century and beyond, the literature suggests that the rate of emissions reductions will need to significantly speed up to stay on track to meet the 2 degrees Celsius warming target and reduce the risk of the most severe projected impacts of climate change.[242]

Realizing Future GHG Reductions: DOE Integrated Modeling Assessment

A disparate set of technologies and Federal and state policies are in place that have reduced and can further reduce emissions from the power sector. An integrated assessment of the roles these varying solutions might play as they compete with and/or complement one another can further inform both policy and technology pathways to achieve the deep decarbonization needed to meet the goals established by more than 190 countries in Paris.

Consumers make their own decisions about how much electricity to use based on their needs as well as electricity prices. The projections described below will provide insight about what could happen to GHG emissions in the future and help inform power companies, regulators, policymakers, and consumers as they make decisions about electricity supply, the performance and cost of technology options, and the appropriate regulatory, market, investment, and incentive structures.

To explore how the electric power sector can contribute to U.S. efforts to address climate change, DOE constructed several illustrative scenarios as part of the analysis conducted for the QER. The scenarios presented here are not intended to be forecasts. Rather, they reveal possible implications for electricity supply, demand, and GHG emissions for a reasonable range of economic and technology assumptions. This analysis used EPSA-NEMS[am] (where EPSA stands for the Office of Energy Policy and Systems Analysis), an integrated energy system model, to explore how electricity demand may evolve and also the potential future composition of the electric power sector, both from the perspective of electricity generation and installed capacity. A summary of the analysis cases is found in Table 3-3.

[am] The version of NEMS used for the EPSA Base Case has been run by OnLocation, Inc., with input assumptions determined by DOE's EPSA. This analysis was commissioned by EPSA and uses a version of NEMS that differs from the one used by the Energy Information Administration. The model is referred to as EPSA-NEMS.

Table 3-3. Summary of DOE QER Analysis Cases using EPSA-NEMS[243, 244]

Case	Description
Base Case	Based on the "Annual Energy Outlook 2015" High Oil and Gas Resource Case, with (1) updated cost and performance estimates for CCUS, solar, and wind, and (2) adjustments to incorporate all existing U.S. policies that were final at the time of this analysis, the most recent of which were the CPP and the December 2015 extension of the Federal Renewable PTC and ITC.[an]
CCUS Incentives Analysis	A variation of the Base Case where the DOE research, development, demonstration, and deployment (RDD&D) program goals for CCUS technologies are achieved. Two potential CCUS incentives are considered: • CCUS incentives in the Administration's fiscal year 2017 budget proposal, including a refundable sequestration tax credit of $10/metric ton CO_2 for EOR storage and $50/metric ton CO_2 for saline storage, and a refundable 30 percent ITC for carbon capture and storage equipment and infrastructure • A hypothetical revision of the Section 45Q sequestration tax credits[ao] to provide a credit of $35/metric ton CO_2 for EOR storage and $50/metric ton CO_2 for saline storage.
Advanced Technology	Current DOE energy program goals (including cost, performance, and deployment goals) overlaid on top of the Base Case.
Stretch Technology	More ambitious RDD&D program goals (including cost and performance goals) overlaid on top of the Advanced Technology Case, based on an assumption of additional RDD&D, such as what could be enabled by Mission Innovation (which will be discussed later in this chapter).
Carbon Price	As a proxy for additional policy action, an initial carbon price of $10/metric ton of CO_2, starting in 2017 and rising at 5 percent per year in real dollars, was overlaid on top of the Base Case, Advanced Technology Case, and Stretch Technology Case.
Side Cases	The Base, Advanced Technology, and Carbon Price (CP 10) Cases were also modeled using the "Annual Energy Outlook 2015" Reference case assumptions instead of the High Oil and Gas Resource assumptions—the "Annual Energy Outlook" Reference case has lower resources (higher natural gas and oil prices). All other inputs explained above stayed the same.

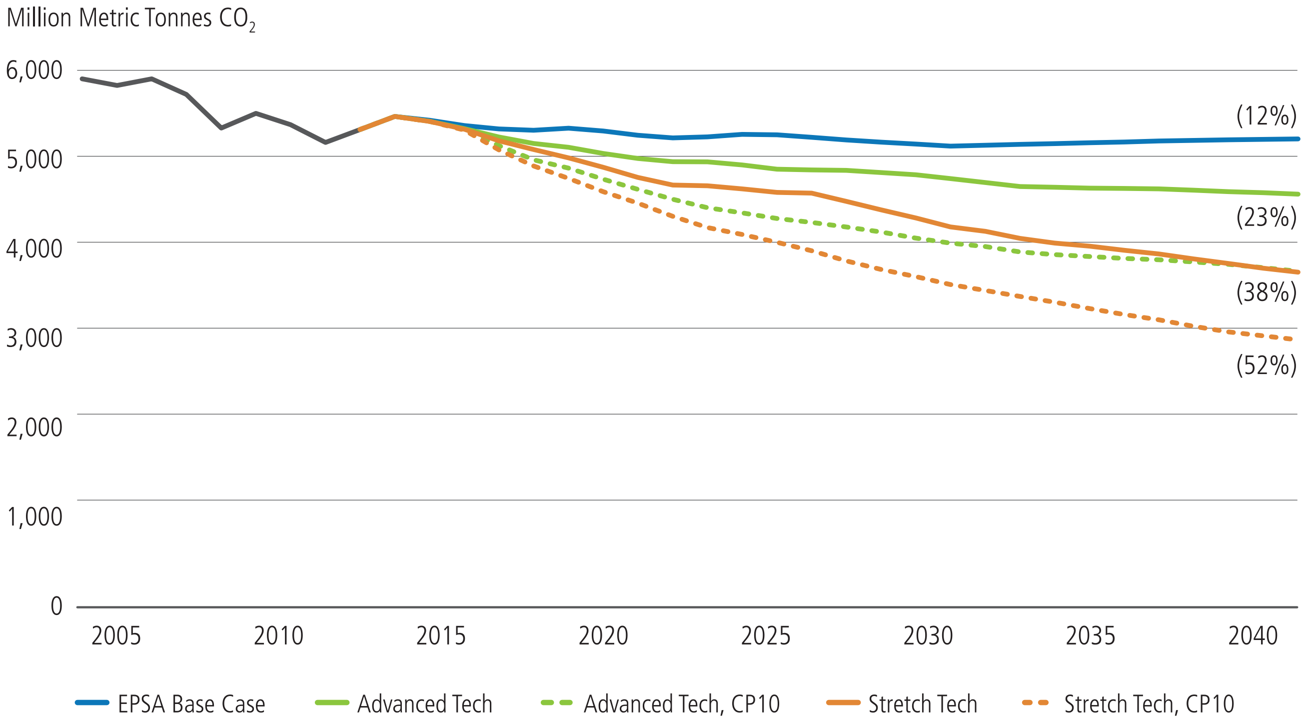
Table 3-3 summarizes the technology and policy assumptions underlying several illustrative analysis cases that DOE constructed to explore how the electric power sector can contribute to U.S. mitigation efforts for climate change.

The resulting range in the projected electricity generation mix for a selected set of cases is shown in Table 3-4. These projections reflect only one possible future for the generation mix. The full range of technologies that could be deployed in a future generation portfolio is still unknown. However, both the Advanced Technology and Stretch Technology Cases see an increase in the market share of many low- and zero-carbon generation sources, particularly when additional policies, such as a carbon price, are applied (Figure 3-18).

[an] The Consolidated Appropriations Act of 2016, signed into law in December 2015, extended the Federal PTC for wind facilities that commence construction before 2020, although the value of the PTC will be phased down for wind projects commencing construction after December 31, 2016. The PTC for all other technologies expired at the end of 2016. The Consolidated Appropriations Act of 2016 also extended the full Federal ITC for solar facilities that commence construction before 2020, after which the value of the ITC will be phased down to 10 percent in 2022 and all years thereafter. The full ITC was also available for large wind facilities through 2016, after which the value was phased down for projects commencing construction before December 31, 2019. The ITC for all other technologies expired at the end of 2016, with the exception of geothermal electric facilities, which receive a 10-percent ITC indefinitely.

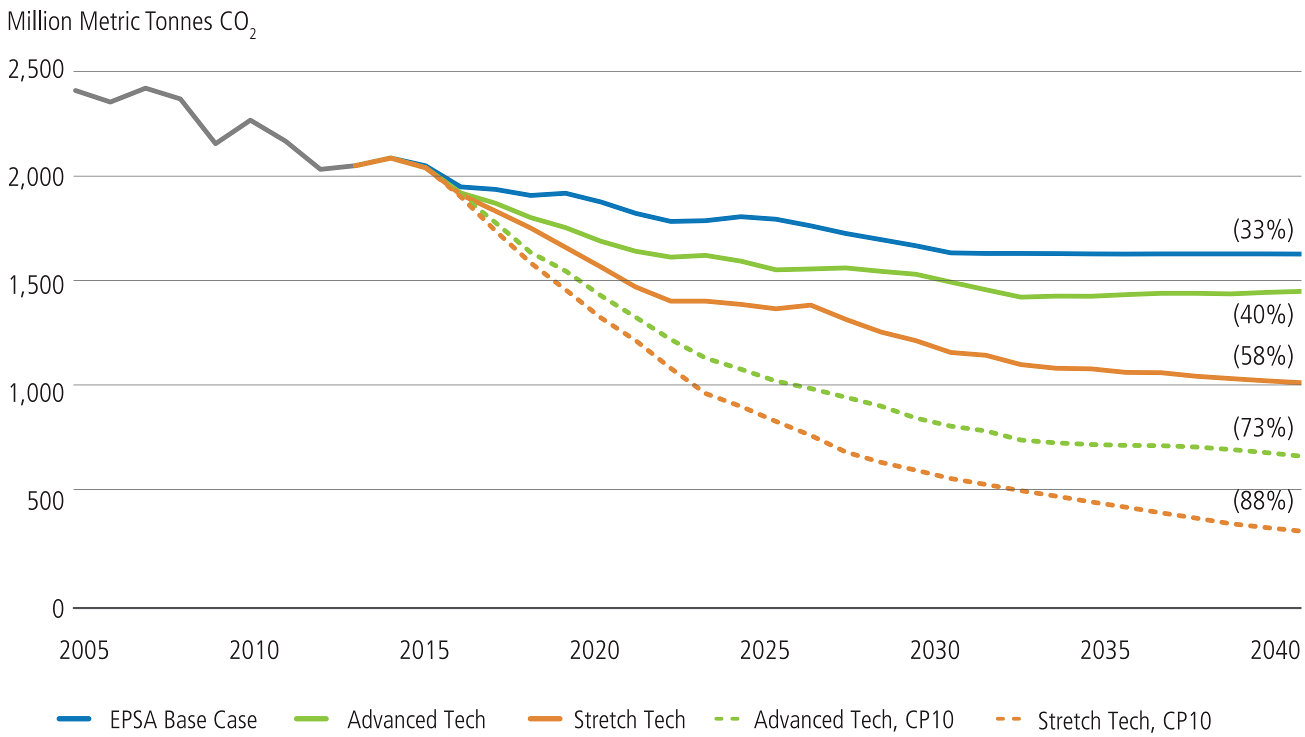
[ao] 26 U.S.C. § 45Q provides a credit for CO_2 sequestration.

Figure 3-18a. U.S. Energy CO_2 Emissions, 2005–2040[245]



Projections of energy CO_2 emissions are shown for several cases along with the corresponding percent decrease in CO_2 emissions relative to a 2005 baseline. These results indicate that successful clean energy research, development, demonstration, and deployment (RDD&D) can drive significant emissions reductions beyond those projected under the EPSA Base Case (which incorporates all existing policies but assumes no new policies). Current levels of RDD&D investment in clean energy technologies (Advanced Technology) can double the projected emissions reductions by 2040, while more ambitious advancements in clean energy technologies (Stretch Technology) could triple the emissions reductions by 2040. These results also indicate that a combination of policy "pull" and technology "push" can achieve much greater reductions than policy or technology alone. Additional technology and/or policies beyond what was modeled are needed to obtain energy CO_2 emissions reductions that are consistent with goals of deep decarbonization.

Figure 3-18b. U.S. Electricity Sector CO_2 Emissions, 2005–2040[246]



Projections of CO_2 emissions associated with electricity generation are shown for several cases. The sharp reductions projected in the near future can be largely attributed to a cleaner electricity generation mix as more high-carbon generation is offset by a variety of low- and zero-carbon generation sources. Reductions in electricity demand, primarily from more efficient building shells and equipment, and faster adoption at lower cost of more efficient building technologies also play a major role in driving down electricity sector CO_2 emissions throughout the analysis. Altogether, these analysis cases show that successful, clean energy RDD&D can drive emissions reductions beyond what is achieved with current policies, measures, and projections for technology advances. In addition, there are multiple pathways to achieving even greater reductions in CO_2 emissions associated with electricity generation through additional technology and/or policies.

DOE performed an analysis to explore the impact of research, development, demonstration, and deployment (RDD&D) and tax incentives on the deployment of CCUS technologies (Table 3-3).[247] The analysis considered tax incentives proposed in the Administration's fiscal year 2017 budget, as well as a hypothetical revision of the Section 45Q sequestration tax credits. The analysis found that Federal RDD&D combined with tax incentives can make CCUS a viable option and that CCUS can play an important role in meeting a carbon policy. DOE's analysis found that CCUS incentives and RDD&D could result in significant deployment of CCUS generating capacity. Under the scenario combining tax incentives with successful RDD&D ("CCUS Incentives Analysis"), coal and natural gas generating capacity with CCUS accounted for an incremental 5 to 7 percent of total generation in 2040 (Table 3-4). For comparison, in 2015, hydropower accounted for 6 percent of total generation, and all other renewables totaled 7 percent of total generation.

Table 3-4. Percentage of Utility-Scale Generation by Fuel Source, and Projected for Selected Cases, 2015–2040[248, 249]

	2015	2040			
Fuel Type	EPSA Base	EPSA Base	Advanced Tech	Advanced Tech CP 10	Carbon Capture, Utilization, and Storage Incentive Analysis
Coal without CCUS	39%	18%–28%	23%–31%	4%–14%	19%
Coal with CCUS	0	<1%	<1%	<1%	3%–4%[a]
Natural Gas without CCUS	27%	21%–42%	11%–28%	13%–31%	37%–38%
Natural Gas with CCUS	0%	0%	0%	1%–2%	2%–3%[a]
Conventional Hydropower	7%	6%–7%	7%	7%–8%	6%
Non-Hydro Renewables	7%	17%–25%	26%–30%	36%–38%	14%
Nuclear Power	20%	17%–19%	15%–20%	21%–28%	17%

[a] Incremental to generation without CCUS.

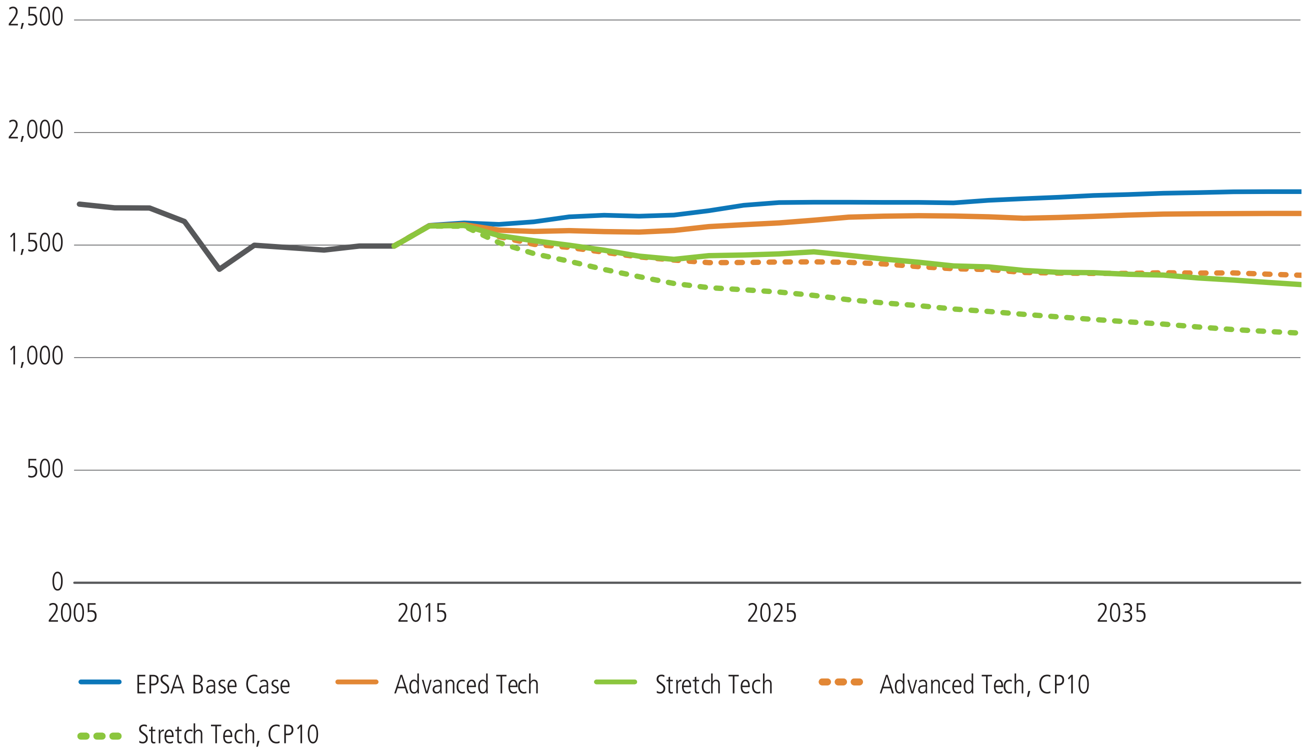
The range in percentages shown in 2040 in the Base Case and Advanced Technology Case highlights the significant impact that future natural gas prices will have on the modeled U.S. electric power generation mix. Similarly, the incentives included in the CCUS Incentives Analysis illustrate the potential to increase penetration of CCUS technologies with additional incentives.

A significant investment in clean energy RDD&D, coupled with an economy-wide policy, would accelerate innovation and technology deployment and reduce CO_2 emissions from the power sector by 88 percent in 2040, relative to 2005 levels.[250] The level of emissions reductions in the Stretch Technology scenario reflects a portfolio approach to RDD&D and is only illustrative, as technology pathways are highly uncertain; unforeseen research breakthroughs are very difficult to anticipate in modeling analysis; and generation breakouts are too uncertain to present here. This uncertainty, coupled with the value of RDD&D in meeting deep emissions reductions, underscores the need for a broad, diverse, and robust research portfolio. Another large source of emissions reductions in the DOE analysis is electricity demand reductions, which can be achieved by technology cost and performance improvements that increase electricity end-use efficiency, and pairing these improvements with a modest carbon price. The modeling analysis suggests that, with these investments and supportive policies, electricity demand would increase by only 5 percent over the next 25 years, compared to 21 percent without them.

Figure 3-19. Total Direct and Indirect CO_2 Emissions by End-Use Sector, 2005–2040[251]

Industrial Sector

Million Metric Tonnes CO_2



Buildings Sector

Million Metric Tonnes CO_2

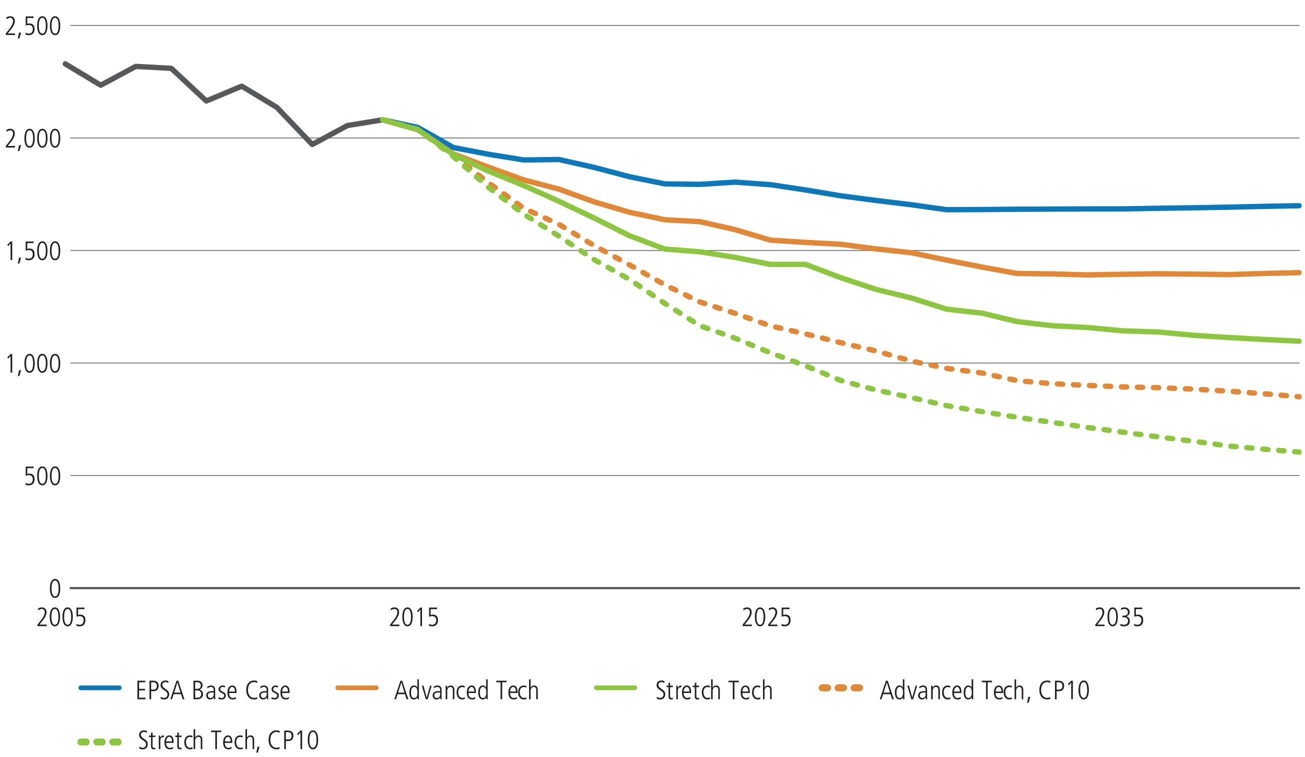
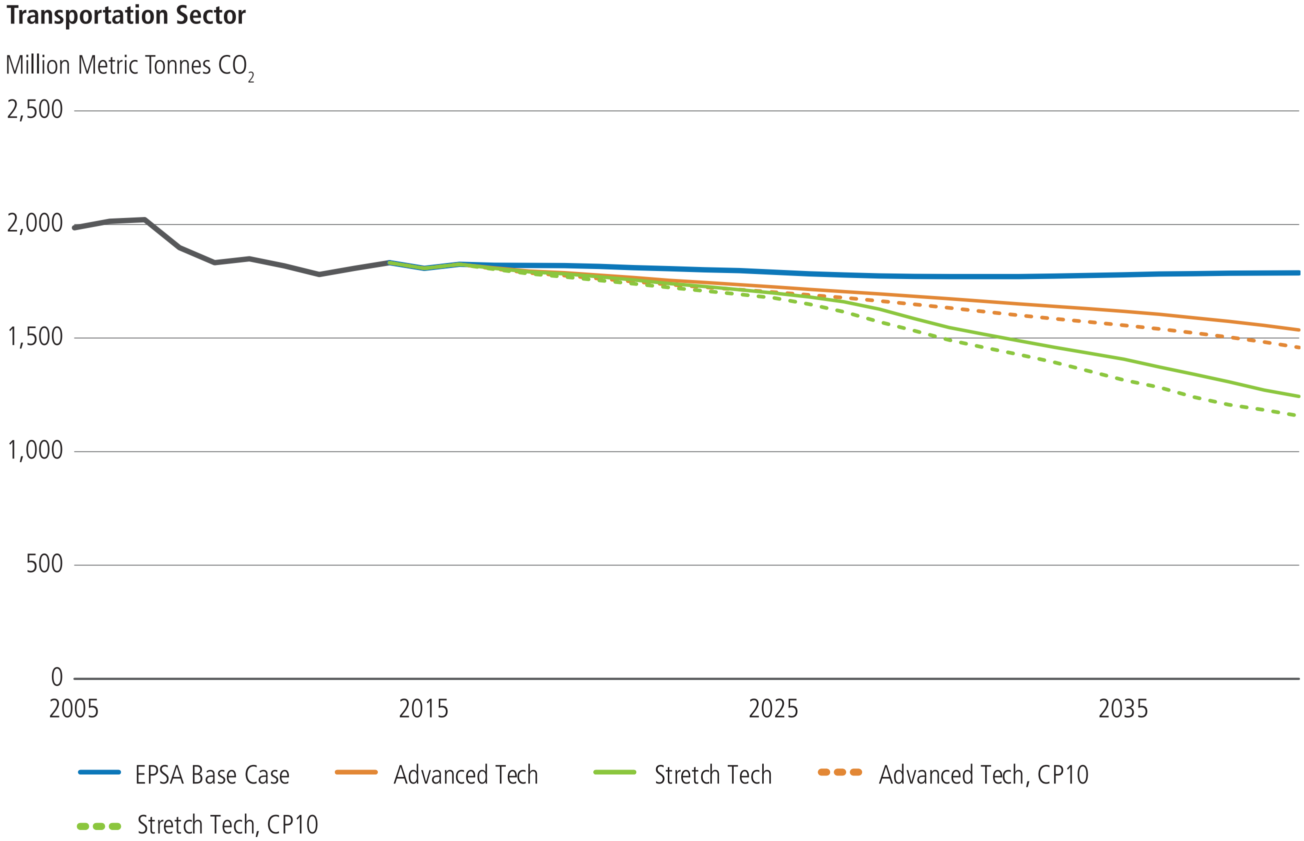


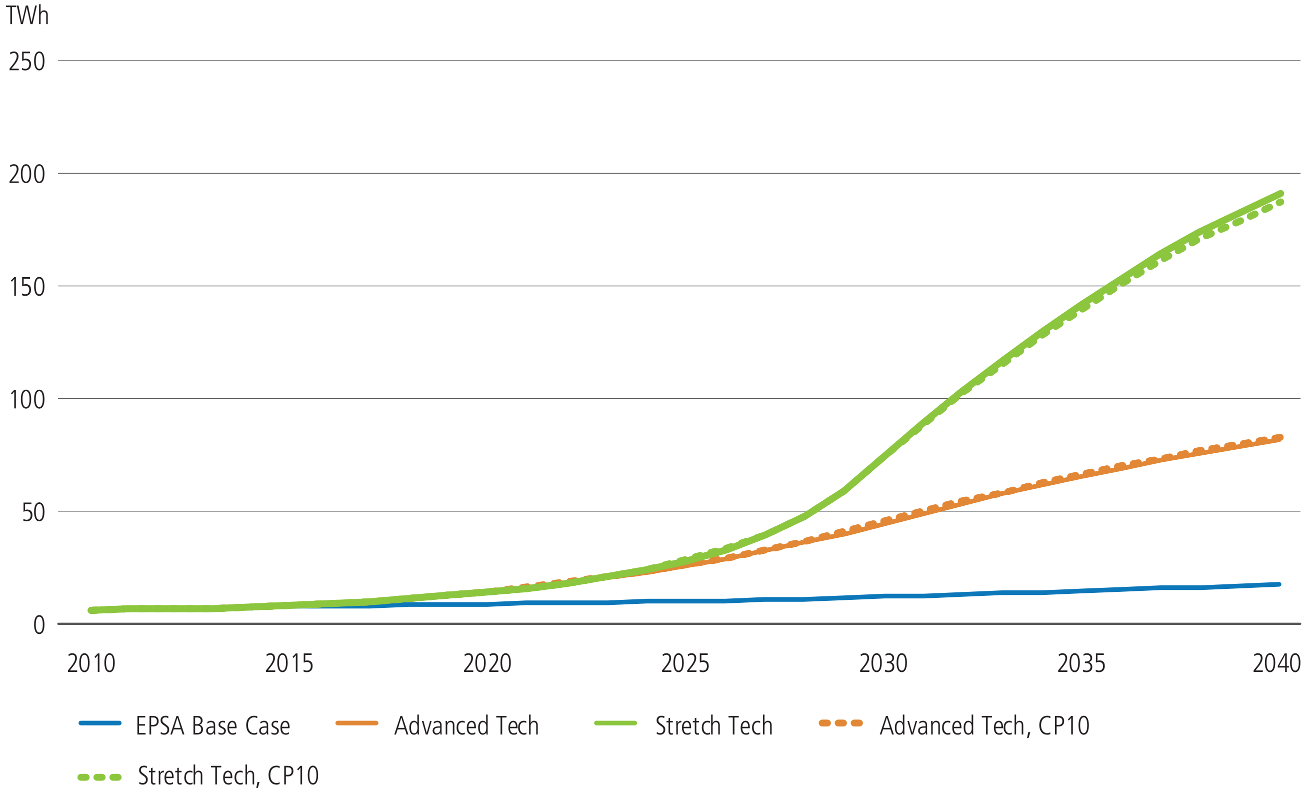
Figure 3-19. Total Direct and Indirect CO_2 Emissions by End-Use Sector, 2005–2040 (continued)



This figure shows the projected impact of technology and policy assumptions on total CO_2 emissions from the industrial (top), buildings (middle), and transportation (bottom) sectors, including emissions associated with both (1) direct fuel use (direct emissions) and (2) electricity generation allocated to end-use sectors based on their electricity use (indirect emissions). Successful clean energy RDD&D is projected to reduce end-use CO_2 emissions by accelerating the transition towards a cleaner electricity generation mix and the adoption of cleaner and more efficient technologies. Both efficiency improvements (especially in energy-intensive industries) and additional policy can drive significant emissions reductions in industry and buildings. Technology advances can have a significant impact in the transportation sector, but the modest carbon price proxy does not dramatically reduce transportation emissions.

In the Stretch Technology Case, even greater investment in successful clean energy RDD&D is projected to result in more significant efficiency improvements, and electricity demand is projected to actually decrease by approximately 1 percent over the next 25 years. In both the Advanced Technology and Stretch Technology Cases, there is a decrease in electricity demand in both the industrial and buildings sectors, primarily due to technology improvements that result in increased efficiency (Figure 3-19). Conversely, in the transportation sector, electricity demand increases as the market starts to adopt more battery electric vehicles; however, electricity use in the transportation sector is still very small compared to other sectors. In 2040, transportation only accounts for 2 percent of electricity demand in the Advanced Technology Case and 6 percent in the Stretch Technology Case (Figure 3-20).

Figure 3-20. Electricity Demand in the Transportation Sector, 2005–2040[252]



The DOE scenarios all project a small but growing shift towards electrification in the transportation sector. In the Advanced Technology and Stretch Technology Cases, advances in RDD&D lead to increased market penetration of alternative vehicles, including battery electric and fuel cell light-duty vehicles. In 2040, battery electric vehicles and hydrogen fuel cell vehicles comprise 18 percent of new light-duty vehicle sales in the Advanced Technology Case and 40 percent of new light-duty vehicle sales in the Stretch Technology Case.

The potential for emissions reductions by specific end-use sectors was also analyzed. Total CO_2 emissions account for both (1) the CO_2 emissions associated with each sector's electricity generation and (2) emissions from direct fuel use (e.g., industrial process emissions and vehicle tailpipe emissions).[ap] Technology advances and/or additional policy are projected to drive dramatic emissions reductions from the buildings sector due to a cleaner electricity generation mix and reduced electricity demand through more efficient building shells and equipment, as well as faster adoption at lower cost of more efficient technologies. Similarly, successful clean energy RDD&D and/or additional policy drive reductions in industrial sector CO_2 emissions through efficiency improvements (especially in energy-intensive industries); additional policy is also projected to have a significant impact. Finally, in the transportation sector, where use of electricity is currently very limited, opportunities exist for significant emissions reductions through efficiency improvements and the successful deployment of electric and hydrogen fuel cell vehicles, but the application of a modest carbon price has only a minor additional impact on transportation emissions.

[ap] Emissions from end-use sectors are typically referred to as indirect emissions (emissions associated with the generation of electricity used by each sector) and direct emissions (direct fuel-use emissions).

In addition to showing the value of synergistic research investments and policy, the analysis shows that the electricity sector is most sensitive to a carbon price policy, partly because it already has a variety of relatively low-cost substitution options available. Finally, this analysis supports the finding that as the electric grid becomes increasingly decarbonized, electrification of end uses can result in further reductions of energy CO_2 emissions.

Need for Accelerated Innovation in the Electricity System

Even with notable increases in clean technology deployment in recent years, the scale-up and speed of clean energy technology[aq] innovation for the electricity system need to accelerate. As noted, increasing RDD&D in conjunction with an economy-wide policy can help the United States meet its NDC. There are also multiple direct and indirect benefits of electricity sector technology innovation investments. Innovation investments directly expand the pipeline of new technologies, reduce technology costs, and mitigate the risks of new technologies or systems. These benefits, in turn, reduce the cost of policies and incentives[253] and allow decision makers in both government and the private sector to consider options that would otherwise not be available. Increased deployment levels due to policies and incentives also increase economies of scale and further reduce manufacturing costs and technical risks. In addition, innovation investments can serve to train the next generation of scientists, engineers, and entrepreneurs for work in the private sector or at universities or other research institutions.[254]

However, comparisons with other innovation-driven sectors and other countries, declining private-sector energy innovation funding, and increasing needs for electricity sector innovation all point to an inadequate level of current support in the United States.[255, 256, 257, 258, 259, 260, 261] For example, annual global corporate and venture capital investment in renewable energy innovation grew from $3.6 billion in 2004 to a peak of $7.6 billion in 2011, but this investment has since fallen to $5.5–$6.0 billion in 2014–2015. Annual global venture capital and private equity investments in early-stage renewable energy firms have fallen even more drastically, from a peak of $9.9 billion in 2008 to $2.1–$3.4 billion in 2013–2015.[262] In the United States, similar trends show that annual venture capital investments in clean energy technologies fell from a 2008 peak of over $5 billion to about $2 billion each year since 2013. From 2006 to 2011, only 5 percent of early-stage clean energy technology firms returned profits to their investors through acquisition or an initial public offering, as opposed to 18 percent of early-stage software firms started during the same period.[263] Private-sector energy firms also spend significantly less on R&D as a percentage of sales than firms in other major technology-dependent sectors, such as pharmaceuticals, aerospace and defense, and computers and electronics.[264] Private-sector investment, while critical, will not likely be made at a pace sufficient to meet national objectives.[265, 266, 267, 268] Electricity sector technology innovation is subject to many barriers. For example, prices do not reflect external benefits[ar] of clean energy; investments are made in a highly regulated environment; and there are high capital costs and long time horizons for RD&D and capital stock turnover in comparison to other sectors, such as information technology. Current levels of Federal support for electricity sector and other energy-focused RD&D need to be substantially increased.[269, 270, 271, 272, 273, 274, 275, 276, 277, 278] Regional variation in innovation capabilities, infrastructure, markets, policies, and resources also points to a need to address electricity sector innovation through regional approaches.[279]

[aq] Clean energy technologies are defined as energy-related hardware, software, and systems that avoid, reduce, or sequester GHG emissions or other air pollutants, including technologies that convert, convey, or store energy resources; improve energy efficiency; or reduce energy consumption.

[ar] R&D is a classic example of an activity that has positive externalities for society. Externalities represent a difference between private and social gains. R&D has positive effects beyond those enjoyed by the producer that paid for the R&D because R&D expands general knowledge, and in turn, enables other discoveries and developments. A private firm only receives benefits from its own products; generally, the private actor does not capture the profits from others who benefited indirectly. With all positive externalities, private returns are smaller than social returns.

The Advanced Research Projects Agency–Energy (ARPA-E) Program and Electricity Innovation

The Department of Energy's ARPA-E funds technically innovative, high-risk, high-potential energy projects that are too early for private-sector investment but could significantly advance how the Nation generates, stores, distributes, and uses energy.[as] ARPA-E competitively supports innovative ideas with the specific purpose of advancing them from early-stage concept to application prototype. One of the Mission Innovation goals that ARPA-E supports is to deliver more investment-ready, innovative energy technologies for private-sector investors and industry to commercialize. To date, 45 ARPA-E projects have attracted more than $1.25 billion in private-sector follow-on funding to support commercial development.

There is significant opportunity for accelerating the development of more innovative project concepts based on the number of applications for ARPA-E projects. On average, ARPA-E is only able to fund 10 percent of the proposals for its focused solicitations, and only 1.4 percent of the proposals that it receives in its open solicitations.[at]

Many of ARPA-E's programs are directly or indirectly focused on breakthroughs for the electricity sector. For example, the Green Electricity Network Integration program has supported the development and demonstration of new grid optimization technologies, such as power flow controllers.[au] By redirecting power away from congested lines, power flow controllers can increase transmission capacity without construction of new assets.[av]

[as] America Competes Act, 42 U.S.C § 149, Subchapter XVII, as amended by Pub. L. No. 110-69 § 5012 (H.R. 2272) and Pub. L. No. 111-358 § 904 (H.R. 5116).

[at] E. Williams and D. Henshall, *Advanced Research Projects Agency-Energy Mission Innovation Context: Overview of Commercialization Activities* (ARPA-E, August 31, 2016).

[au] T. Heidel, "GENI Program Overview & Introductions" (presented at Green Electricity Network Integration Annual Program Review, New Orleans, LA, January 14–15, 2015), http://arpa-e.energy.gov/sites/default/files/A_GENI%20Intro_Heidel.pdf.

[av] Electric Power Research Institute (EPRI), *Benefits and Value of New Power Flow Controllers*, July 2016 Draft (EPRI, forthcoming).

The spectrum from early- to late-stage energy innovation spans a highly interactive process that includes invention, translation, adoption, and diffusion. These four stages, which continually influence each other, roughly correlate to the classic linear innovation categories RDD&D.[280] Challenges to accelerating electricity sector technology innovation vary widely between technologies and innovation stages.

For example, some electricity sector technologies, such as nuclear, CCUS, and offshore wind, have capital costs that comprise a relatively high share of total costs compared to other technologies. High-capital-cost projects typically require first-of-a-kind demonstrations at commercial scale where system engineering challenges and large infrastructure costs predominate. Commercial-scale demonstrations often take tens or hundreds of millions of dollars to execute and may carry high technical and market risk.[281] These challenges can simply be too large for a single firm to take on, and the time to provide a return for private investors is often longer than investors can wait.[282]

Although there is substantial research on the value and impact of energy technology innovation, particularly for individual technologies, there are few robust measures and quantitative assessments of the energy innovation system, particularly of private-sector inputs, as well as meaningful outputs and impact measures. Refined, data-driven frameworks and models on energy innovation, including policy interactions, are needed to understand better how inputs and outputs of energy innovation systems relate to each other.[283, 284, 285, 286, 287]

Electricity sector technology areas that received substantial investment increases in the fiscal year 2017 President's budget include energy storage; grid modernization; energy-water nexus; subsurface science, technology, and engineering; CCUS; and renewable generation technologies, such as solar, wind, water, and geothermal. Promising breakthrough technology areas include improving flexible power delivery and communications; developing non-vapor compression systems that provide highly energy-efficient space conditioning, water heating, and refrigeration services in buildings without the use of traditional refrigerants; producing low-cost hydrogen from renewable or low-carbon sources; scaling up novel CO_2-capture technologies from power plants and industrial sources; and recycling CO_2 into valuable products as a feedstock.

Mission Innovation: Accelerating Clean Electricity Technology RDD&D

In November 2015, the United States and 19 other nations came together to make a landmark commitment—called Mission Innovation—to dramatically accelerate global clean energy innovation. This charter group of Mission Innovation countries, as well as others that have joined since, are seeking to double their public investment in clean energy R&D over 5 years. Accordingly, Mission Innovation will result in nearly $30 billion of public investment in 2021.

The "Enabling Framework for Mission Innovation" outlines examples of proven and powerful approaches to RD&D that will be critical elements of the U.S. domestic implementation of Mission Innovation.[288] Robust implementation must incorporate multiple linear and nonlinear approaches, not just in terms of technologies, but also in terms of technology pathways. This means funding programs that leverage foundational mechanisms to increase breadth of knowledge within a scientific discipline; translational mechanisms to target incremental improvements along defined tech-roadmaps; disruptive mechanisms to validate high-risk, high-reward off-roadmap ideas; and integrational mechanisms to facilitate collaboration across disciplines and stakeholders.

The Framework uses five specific areas of focus to illuminate these opportunities, all of which are either specifically or partly related to electricity: generation (i.e., harnessing electricity from clean sources); mobility (i.e., moving people and goods using clean energy); connections (i.e., delivering clean energy from supply to demand); structures (i.e., innovating better buildings); and processes (i.e., using clean energy to create products and grow food). As outlined in the "Domestic Implementation Framework for Mission Innovation,"[289] the domestic implementation of Mission Innovation could

- "*Drive down energy costs:* Clean energy technologies have the potential to dramatically reduce long-term energy expenditures.[290] This could increase the competitiveness of U.S. businesses and put thousands of dollars in the pocketbooks of American families.
- *Enhance system reliability:* Energy services are deeply embedded into all critical infrastructures and services, including the electric grid, transportation, and telecommunications. Advanced energy technology can improve system reliability.
- *Improve energy security:* Using more diverse energy sources and technologies can increase the resilience and flexibility of the domestic energy supply chain, helping to protect energy consumers from high-cost market disruptions and reducing exposure to markets with high price volatility, like oil.
- *Curb adverse environmental and public health effects:* Energy-related GHG emissions are the dominant cause of climate change. Clean energy technology is the largest—and most essential—component of mitigation. The shift to clean energy will also reduce the other harmful pollutants associated with energy use, improving health outcomes.
- *Build economic opportunities:* Maintaining our technological edge will enable opportunities to export our clean technologies, products, and services to other countries.[291] Clean energy can be a major opportunity to create new jobs, enable domestic manufacturing, and catalyze industries.[292, 293]

- Improve energy access and equity: In many rural and remote places in the United States, communities lack access to reliable and affordable energy services. Advanced energy technologies can support universal energy access, helping boost quality of life and economic development."[294]

Recent analysis suggests programs and investments in technologies supported by initiatives like Mission Innovation could help create significant global opportunities for U.S. businesses and technologies in the following regions of the world:

- "*East Asia and the Pacific:* [G]reen buildings—China, Indonesia, the Philippines, and Vietnam show a climate-smart investment potential of $16 trillion.
- *Latin America and the Caribbean* offer the next largest opportunity—particularly in sustainable transportation, where the potential for investment in Argentina, Brazil, Colombia, and Mexico is about $2.6 trillion.
- *South Asia:* Opportunities are mostly seen in climate-resilient infrastructure, where $2.5 trillion of opportunities exist in India and Bangladesh.
- *Sub-Saharan Africa* represents a $783 billion opportunity—particularly for clean energy in Cote d'Ivoire, Kenya, Nigeria, and South Africa.
- *Eastern Europe,* with its biggest markets—Russia, Serbia, Turkey, and Ukraine—shows a combined investment potential of $665 billion, mostly in energy efficiency and new green buildings.
- *Middle East and North Africa:* [T]he total climate-investment potential for Egypt, Jordan, and Morocco is estimated at $265 billion, over a third of which is for renewable-energy generation, while 55 percent ($146 billion) is for climate-smart buildings, transportation, and waste solution."[295]

Environmental Impacts of Electricity on Air, Water, Land Use, and Local Communities

Infrastructure associated with electricity operations has a range of direct impacts to ecosystems and natural resources. The magnitude of impacts depends on how the infrastructure affects endangered species, sensitive ecological areas, or cultural or historic resources; gives rise to visual or aesthetic concerns; or opens new areas to development.[296] Achieving the deep decarbonization of the electricity sector necessary to reach national climate targets will require a significant scaling up of clean energy technology. While Federal, state, and local governments have made strides in assessing the ecological and land-use impacts of current technology—as well as water-use and water-quality impacts—more analysis will be helpful to scale deployment of additional clean energy technologies. Considering the ecological impacts and natural resource implications of new energy technologies in the R&D phase may help avoid the aforementioned impacts and the need to mitigate them. Decreasing land-use and ecological impacts will expand the universe of geographically suited areas for clean energy technology. Further refinement of mitigation policies for those technologies requiring mitigation is also needed.

Air and Water Pollution

The United States has made remarkable progress improving air and water quality under the CAA, the Clean Water Act, and other environmental statutes, but the United States must continue to address emissions, including from the electric sector. For example, the most-polluting power plants still have criteria air pollutant emissions per unit of electricity that are many times larger than the least-polluting power plants.[297]

Direct air pollutants from the electricity system include SO_2, NO_x, some particulate matter (PM), and mercury and other air toxic pollutants. In addition, these pollutants react in the atmosphere to form secondary pollutants—including acid rain, other PM, and ground-level ozone—that adversely impact air quality. These pollutants increase morbidity and the risk of mortality, reduce agricultural and timber productivity, deteriorate materials, reduce visibility, and harm ecosystems.[298, 299, 300, 301, 302]

In 2009, EPA determined that GHG pollution threatens Americans' health and welfare by leading to long-lasting climate changes that can have a range of negative effects on human health and the environment (Table 3-5).[303] Climate change can "affect human health in two main ways: first, by changing the severity or frequency of health problems that are already affected by climate or weather factors; and second, by creating unprecedented or unanticipated health problems or health threats in places where they have not previously occurred."[304] A U.S. Global Change Research Program report notes: "Given that the impacts of climate change are projected to increase over the next century, certain existing health threats will intensify and new health threats may emerge."[305] In particular, air pollution and airborne allergens will likely increase, worsening allergy and asthma conditions due to climate change. Future ozone-related human health impacts attributable to climate change are projected to lead to hundreds to thousands of premature deaths, hospital admissions, and cases of acute respiratory illnesses each year in the United States by 2030, including increases in asthma episodes and other adverse respiratory effects in children.[306] Ragweed pollen season is longer now in central North America, having increased by as many as 11 to 27 days between 1995 and 2011, which impacts some of the nearly 6.8 million children in the United States affected by asthma and susceptible to allergens due to their immature respiratory and immune systems.[307]

Table 3-5. Summary of Physical Impacts of the Most Common Air Pollutants[308, 309, 310, 311]

	Human Health	Crops and Timber	Materials	Visibility	Recreation
NO_x	Chronic obstructive pulmonary disease		Material deterioration		Eutrophication
	Ischemic heart disease				
SO_2	Asthma	Damages to forests	Material depreciation		Damages to forests
	Cardiac				
O3 (ozone)	Chronic asthma	Crop loss Timber loss	Rubber deterioration		Damages to forests and wilderness areas
	Acute-exposure mortality				
	Respiratory problems				
	Acute asthma attacks				
$PM_{2.5}$	Premature death			Loss of visibility	
	Nonfatal heart attacks				
	Hospital admissions				
	Emergency Room visits for asthma, acute bronchitis, upper and lower respiratory symptoms				
$PM_{10–2.5}$	Chronic bronchitis				

Major impacts of air pollution are delineated by sector and pollutant. $PM_{2.5}$ is particulate matter with a diameter of 2.5 micrometers or less. $PM_{10–2.5}$ is coarse particulate matter with diameter between 10 and 2.5 micrometers.

As of 2014, electricity generation accounted for 64 percent of economy-wide SO_2 emissions and 14 percent of NO_x emissions; power plants were the dominant emitters of mercury (50 percent) and acid gases (75 percent).[312, 313] Within the electricity system, coal combustion accounts for the vast majority of pollutants.[314] While a majority of power plants use scrubbers and other pollution controls to reduce emissions of multiple pollutants, some power plants still do not employ the full suite of available pollution controls or do not control for all pollutants.[315]

Additionally, steam electric power[aw] plants generate wastewater streams from their water treatment, power cycle, ash handling, air pollution control systems, coal piles, and other miscellaneous wastes that can impact ground water and surface water quality.[316] Currently, steam electric power plants account for about 30 percent of all toxic pollutants—including mercury, arsenic, selenium, cadmium, and other toxic metals—discharged into surface waters in the United States.[317] These pollutants can cause severe health and environmental problems in the form of cancer and non-cancer risks in humans, lowered IQ among children, and deformities and reproductive harm in fish and wildlife.[318] In 2015, EPA established new limits on wastewater discharge from power plants that are projected to reduce discharge of the most toxic pollutants by over 90 percent.[319, 320]

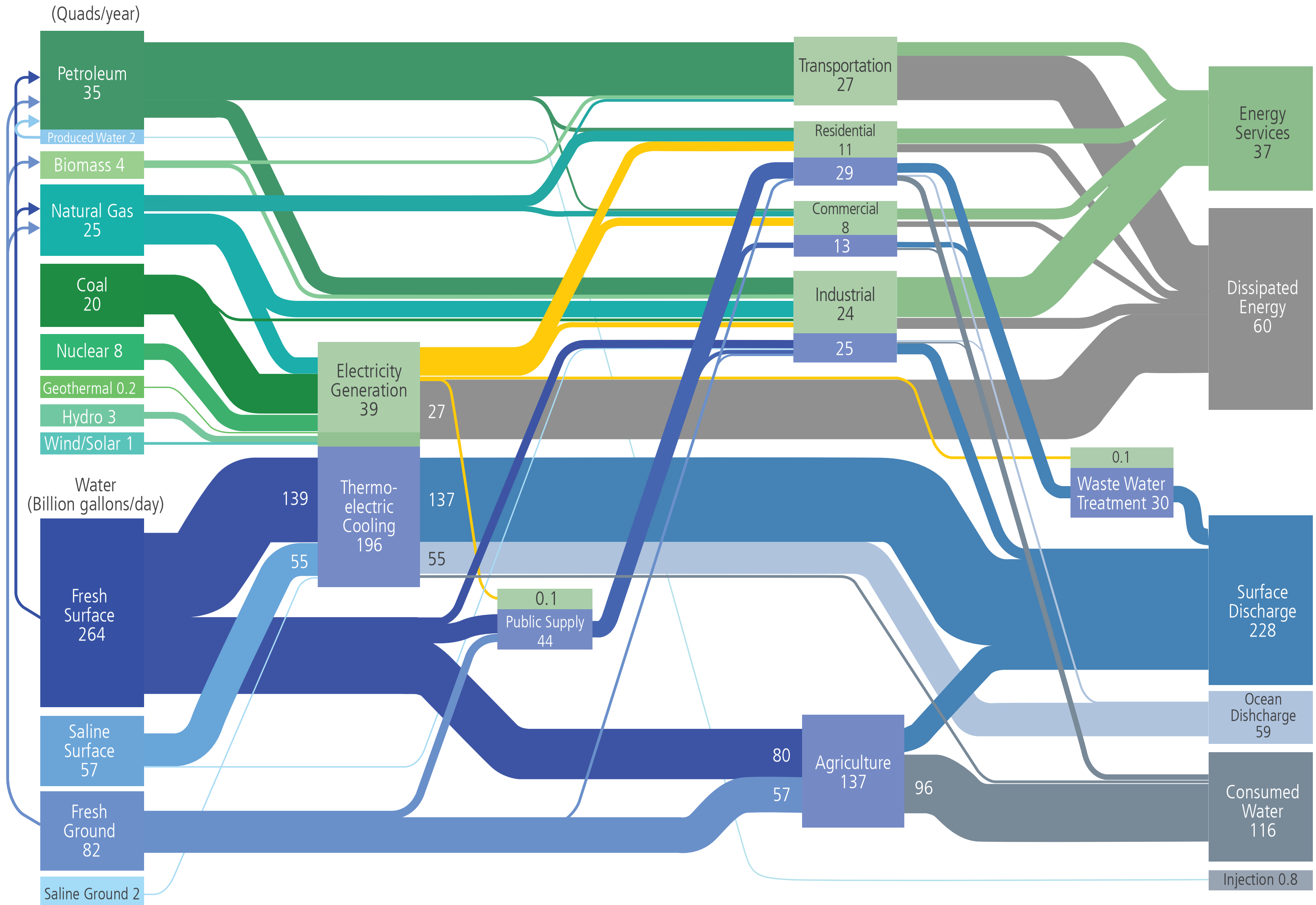
Federal and state governments are continuing their efforts to invest in and incentivize more efficient, less-polluting power plant technologies and to update regulations such as the final Federal Cross-State Air Pollution Update Rule, among other actions. In addition, regulation of CO_2 emissions from power plants is expected to reduce emissions of other air pollutants, creating additional health and environmental benefits in addition to the avoided climate change impacts.[321] The remaining pollution disproportionately affects environmental justice communities. Environmental justice communities are also disproportionately impacted by climate change because they have less resilience capacity.

Role of Water in Thermoelectric Power Generation

Electricity systems and water systems are strongly interconnected. Water is a critical requirement for many electricity generation technologies. Two-thirds of total U.S. electricity generation—including many coal, natural gas, nuclear, concentrated solar power (CSP), and geothermal plants—requires water for cooling. In addition, CCUS technologies have significant water demands. From a full-system perspective, the joint reliance of the electricity and water systems on each other can create vulnerabilities (e.g., drought impacts thermoelectric generation and hydropower), but this joint reliance can also create opportunities for each system to benefit the other through well-designed integration (Figure 3-21 shows connections between energy and water systems).

[aw] A steam electric power plant is a power plant in which steam is used to generate electricity. In particular, water is boiled to generate steam, which, in turn, spins a steam turbine that drives an electrical generator. Most coal, geothermal, solar thermal, nuclear, and waste-incineration plants and some natural gas power plants are steam electric power plants.

Figure 3-21. Hybrid Sankey Diagram of U.S. Interconnected Water and Energy Flows, 2011[322]



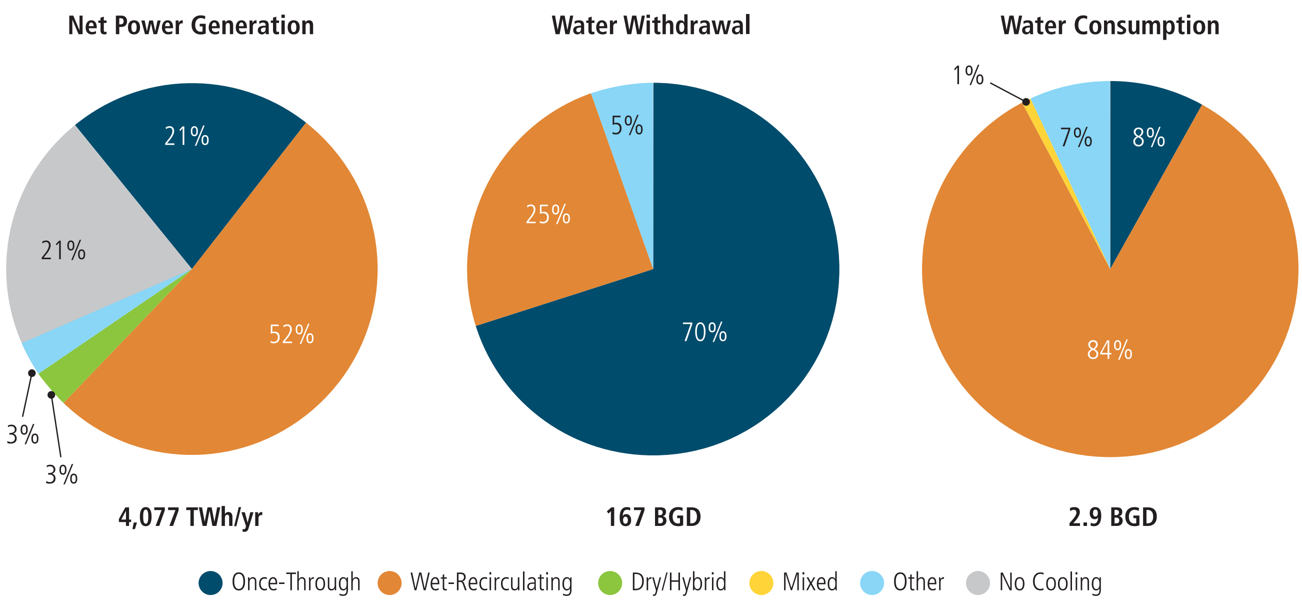
Significant fractions of surface freshwater withdrawals are for thermoelectric cooling and for agriculture, but agriculture consumes more water than thermoelectric cooling consumes. Most electricity is generated for residential, commercial, and industrial use, but significant fractions are used for public water supply and wastewater treatment. The Sankey diagram aids in visualizing these complex data streams and interconnections as a first step toward further analysis.

Several recent trends are particularly important for electricity systems. First, the rising share of wind turbine and solar PV generation requires negligible water for operations. Second, the amount of water *withdrawn* for thermoelectric cooling[ax] has decreased as older plants are decommissioned and more water-efficient or dry-cooled[323] systems are installed. However, water *consumption* in thermoelectric plants is rising as evaporative cooling has become the preferred cooling technology for new plants. In addition, there are water implications of the technology path pursued to address climate change. (Figure 3-22 provides a breakdown of generation, water withdrawal, and water consumption by cooling type.)

Thermoelectric power generation withdraws large quantities of water for cooling power-producing equipment and condensing steam. It also dissipates large quantities of primary energy due to the process of converting thermal energy to electricity. In 2010,[ay] 45 percent of total U.S. water withdrawals were for thermoelectric cooling alone, making thermoelectric generation the largest withdrawer of combined fresh and saline water nationally.[324] Seventy-two percent of these withdrawals for thermoelectric cooling were fresh surface water, 0.4 percent were fresh groundwater, and the remaining were from saline sources.[325]

The intensity of water use and energy dissipated varies with cooling system technology and generation type, as well as operations. Once-through cooling typically withdraws more water but consumes less than a wet-recirculating system. Dry cooling and wet tower capital and operating costs are significantly higher than for once-through, with dry cooling being the most expensive. Dry cooling units also induce efficiency penalties, raising the possibility of potentially creating tradeoffs between addressing water and climate resilience versus climate mitigation, which could be improved with new technologies.

Figure 3-22. U.S. Power Generation, Water Withdrawal, and Water Consumption by Cooling Type, 2015[326, 327, 328, 329]

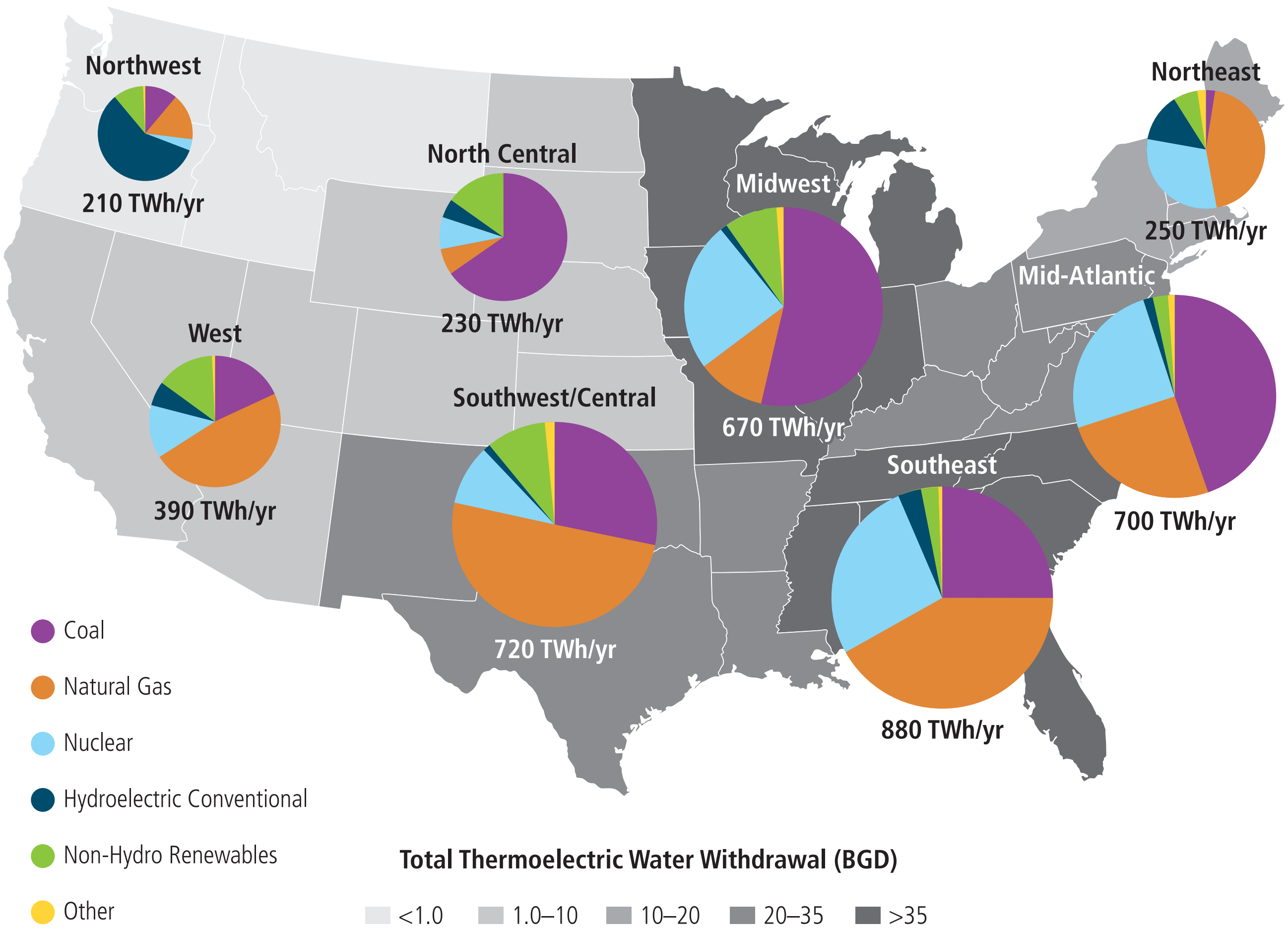


In 2015, nearly 21 percent of generation used once-through cooling, and 52 percent of generation used wet-recirculating cooling. About 21 percent of the electricity generated—including hydropower, natural gas turbines, and wind turbines—did not require cooling. Water withdrawals for electricity generation totaled 167 billion gallons daily (BGD), the majority of which was withdrawn by once-through cooling. Water consumption totaled 2.9 BGD, with 84 percent of this amount consumed by wet-recirculating cooling.

[ax] "Withdrawal" designates any water diverted from a surface or groundwater source. "Consumed water" designates withdrawn water that is not returned to its source (e.g., because it has evaporated, been transpired by plants, or incorporated into products).

[ay] The U.S. Geological Survey collects data on water usage by water source every 5 years and publishes these data near the beginning of the next data-collection cycle.

Figure 3-23. Water Withdrawal and Generation by Region, 2015[330, 331]

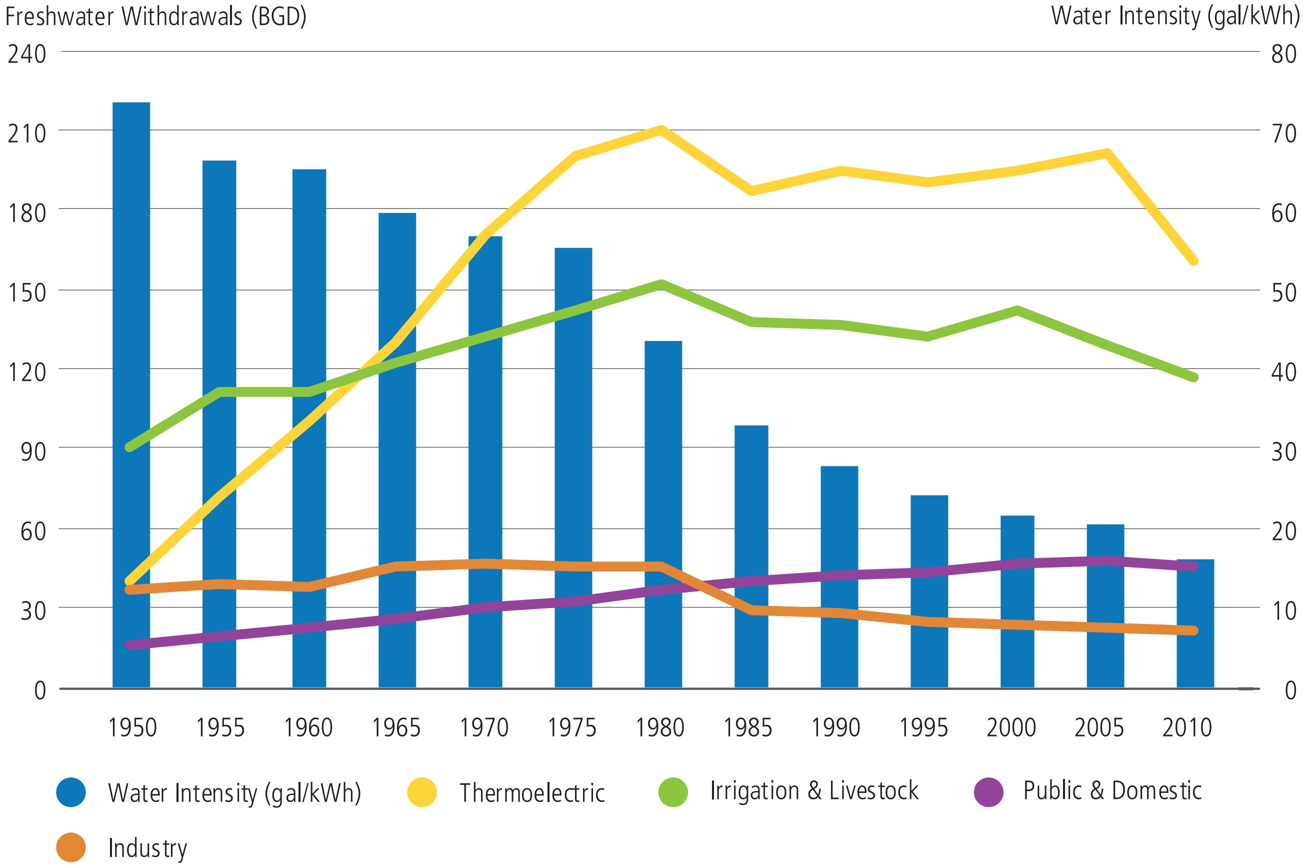


The largest water withdrawal regions are dominated by coal and/or nuclear power generation. The area of each pie chart corresponds to total power generation in that region. "Other" includes petroleum, other fossil fuels, pumped storage, non-biogenic municipal solid waste, batteries, and hydrogen. The eight regions shown in the figure are notional, based upon contiguous groupings of states and their generation mixes, resources, and market structures. Acronym: billion gallons daily (BGD).

Regionally, water withdrawal and consumption vary significantly across the United States, primarily due to the power generation mix and cooling system type. Figure 3-23 shows the amount of water withdrawal for different types of thermoelectric generation in eight notional regions within the 48 contiguous states. The notional regions are based on contiguous groupings of states and their generation mixes, resources, and market structures. While water withdrawals in all eight regions are dominated by surface water, the Southeast, Southwest/Central, and West regions consume higher levels of groundwater and reclaimed plant discharge water relative to other regions. The regions with the largest water withdrawal are dominated by a combination of coal and nuclear power generation.

Since the 1950s, the amount of water withdrawn per kWh has steadily declined as power generation and cooling technologies have become more efficient over time. The total amount of water withdrawn across all thermoelectric plants, however, has steadily and dramatically increased relative to irrigation, industry, and public use (Figure 3-24). Much of this increase is due to build-out of once-through cooling systems for the coal and nuclear fleets. By the 1970s, the wet-recirculating system became the dominant cooling system—as these systems withdraw less water, thermoelectric withdrawals leveled off.[332, 333]

Figure 3-24. Water Withdrawals for Thermoelectric Generation and Other Sectors[334, 335]

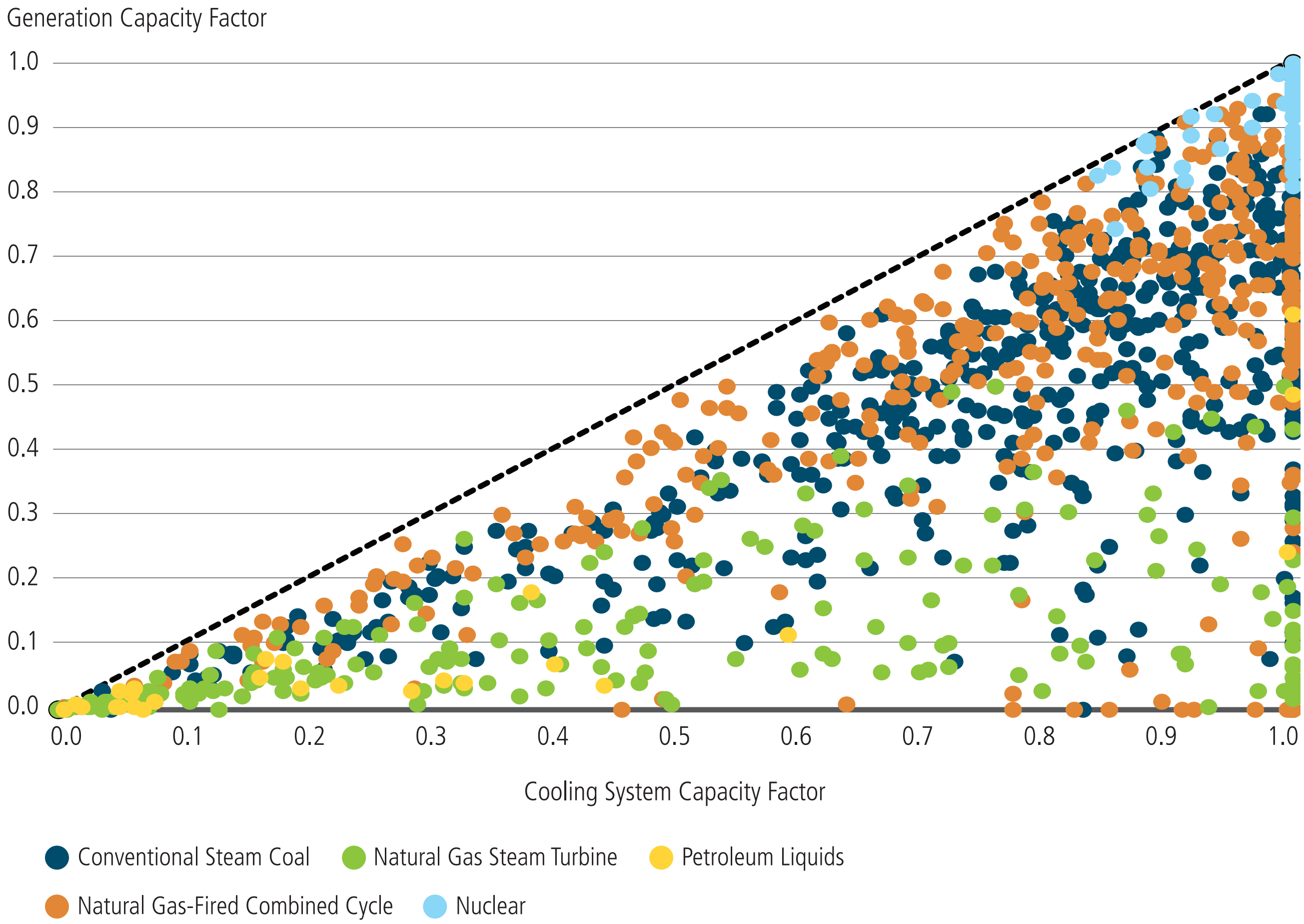


The water intensity of thermoelectric generation (represented by bars) has decreased over time. The total amount of water withdrawn by thermoelectric generation (represented by colored lines) has increased significantly relative to other sectors, but it is now declining. Acronym: billion gallons daily (BGD).

Some operational practices also affect water use. For example, some peaker power plants, such as natural gas steam turbines with low capacity factors, run their cooling systems for a substantial fraction of the time when they are not generating electricity (as the comparison between capacity factors for generation vs. cooling systems shows in Figure 3-25); they also withdraw a significantly higher amount of water than NGCC plants. There are many potential explanations for this behavior. When plants are not generating electricity, they may decide to keep their cooling systems running in order to minimize biofouling and corrosion, especially in hot and humid climates. They may also opt to keep their cooling system running so they can be responsive to increases in demand from end users or decreases in supply from variable generation. There may be operational best practices that better optimize the tradeoffs between load balancing, avoiding biofouling and corrosion, and minimizing water use.

Most types of variable generation do not require water for cooling purposes, but they can put pressure on the system to provide load balancing, usually in the form of dispatchable generation that does require water for cooling. These indirect effects increase the value proposition for other forms of load balancing, such as grid storage or DR.

Figure 3-25. Cooling System Capacity Factors vs. Generation Capacity Factors, 2015[336]



Electricity generators run their cooling systems with varying capacity factors relative to their generating capacity factors. Natural gas steam turbines (Rankine cycle plants)—many likely acting as peakers—run their cooling systems for a substantial amount of time when they are not generating, as do a number of NGCC plants. Plants on the dotted line run their cooling systems with the same capacity factor as their power generation capacity factor (i.e., only when they are generating). Plants that are dispatched primarily during times of peak electricity demand are considered peaking plants and will generally have lower power generation capacity factors. Plants used for baseload electricity will generally have higher power generation capacity factors.

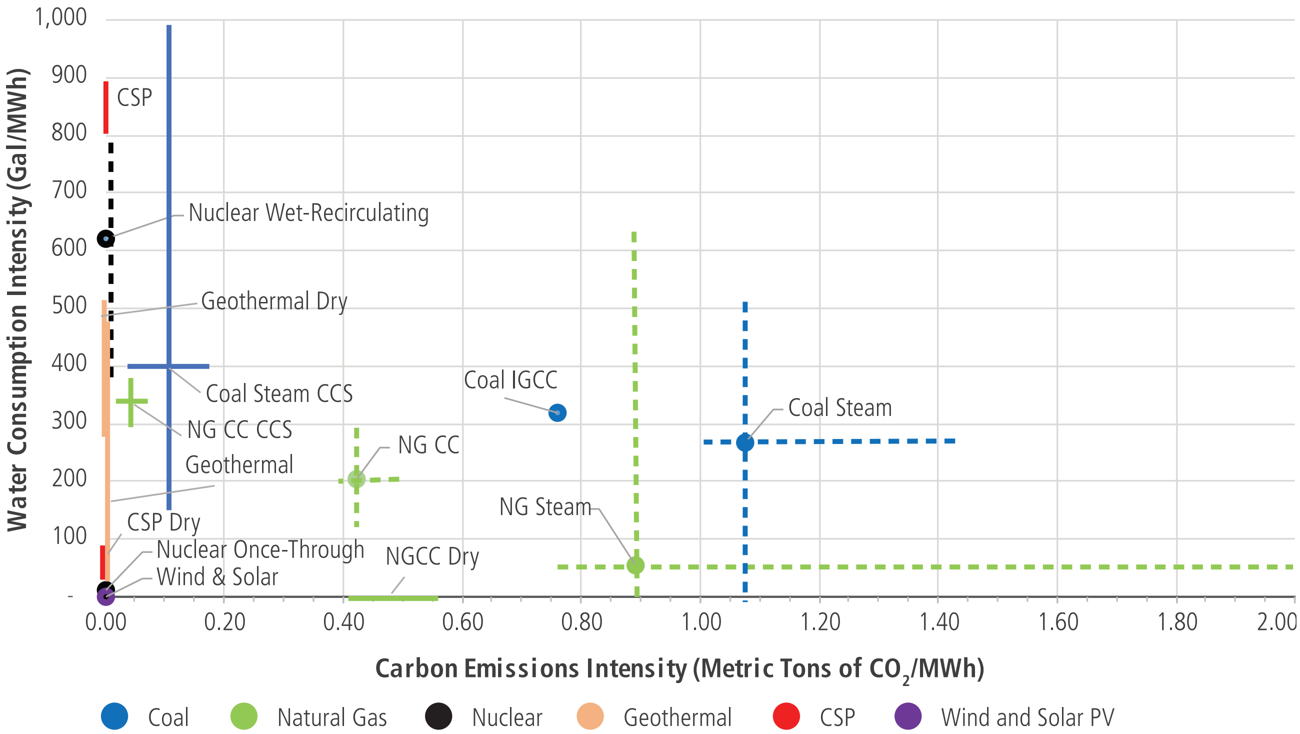
Low-Carbon Generation and Water

The mix of the generation portfolio deployed to reduce GHG emissions will have implications for water withdrawal and consumption. New electricity generation that requires cooling will likely employ recirculating systems, which generally have low water withdrawal but high water consumption. Figure 3-26 shows that some generation technologies can have both low water use and carbon intensities, such as PV and wind, while other generation technologies present tradeoffs between water and carbon emissions.

Some low-carbon technologies, such as nuclear generation, geothermal generation, CSP, and CCUS, require relatively large amounts of water. Incorporating water-use and performance metrics into RDD&D funding criteria for these low-carbon technologies could improve the options available for climate mitigation and resilience.

Conversely, dry cooling, which greatly reduces water requirements for thermoelectric cooling, generally induces an energy efficiency penalty, particularly under high-temperature ambient conditions. This increases the carbon intensity of generation, as well as other adoption challenges. However, dry cooling systems offer significant siting flexibility as they do not require access to large volumes of water. At present, there are 74 dry or hybrid cooling systems that provide 53 TWh of net generation in the United States, most of which have been deployed in NGCC plants since 2000. The energy penalty for current dry cooling technologies relative to once-through cooling ranges from 4.2 percent to 16 percent for a representative 400-MW coal-fired plant, depending on plant parameters and ambient conditions.[337] In addition, existing dry (air-cooled) options have higher capital costs and require expanded physical footprints.[338]

Figure 3-26. Carbon Emissions and Water Consumption Intensity Tradeoffs[339, 340, 341, 342, 343, 344]



Some generation technologies (e.g., solar PV and wind) can have both low water and carbon intensities, while other generation technologies present tradeoffs between water and carbon emissions. For example, low-carbon technologies, such as nuclear, geothermal, and CSP generation, along with carbon capture and storage (CCS), require large amounts of water. Conversely, dry cooling, which greatly reduces water requirements for thermoelectric cooling, often induces an efficiency penalty, which increases the carbon intensity of generation. Dotted lines represent ranges calculated from data, and solid lines represent ranges from literature values.

Through the Advanced Research in Dry Cooling program, the Advanced Research Projects Agency–Energy (ARPA-E) has invested about $30 million to advance dry-cooling technologies. The program aims to develop dry-cooling technologies that do not consume any water, eliminate efficiency penalties, and do not increase the LCOE by more than 5 percent. Reaching this target would allow for reduced water use for cooling without an additional energy efficiency penalty. In addition, DOE has supported designs for advanced nuclear reactors that use molten salt rather than water as a cooling fluid.

More broadly, there are both opportunities and tradeoffs in energy and water systems integration (e.g., in using treated municipal wastewater for thermoelectric cooling, or in recovering energy from wastewater systems). Making design decisions about how and when to integrate electricity and water systems at multiple spatial and temporal scales is a major challenge that involves a number of actors. Design of more integrated policies and decision-making frameworks that take both opportunities and tradeoffs into account could unlock additional value for electricity and water systems.

Land-Use and Ecological Impacts of the Electricity System

The land-use footprint of electricity infrastructures and associated operations has a range of direct impacts to ecosystems and to society more broadly. The magnitude of these impacts depends on how the infrastructure affects endangered species, involves sensitive ecological areas, impacts cultural or historic resources, gives rise to visual or aesthetic concerns, or opens new areas to development.[345] While expanding transmission and distribution (T&D) infrastructure can pose environmental challenges, building new infrastructure can also help to enable significant net environmental benefits. This section discusses considerations that are common to the land-use and ecological impacts of electricity infrastructure, including descriptions of the land-use requirements and ecological impacts of different types of power plants and T&D infrastructure. This section only touches on a few of the most significant ecological impacts that occur upstream of generation, transmission, and distribution. A more detailed examination of these important impacts is beyond the scope of QER 1.2.

Land-Use Impacts

For all technology types, the siting of power plants involves the transformation of the existing landscape, the removal of soil and ground vegetation, and the potential for erosion and sedimentation loading to waterways during construction. However, other land-use requirements vary according to the generation infrastructures and their associated operational requirements. Life-cycle land-use impacts of fossil and nuclear plants, when accounting for extraction and waste disposal, are significant; however, the power plants themselves feature relatively small footprints. Conversely, renewable generation life-cycle land-use impacts are minor, with generation facilities having significantly larger footprints.

There is limited literature comparing land-use impacts across generation technologies.[346] One 2009 study, however, sought to normalize life-cycle land requirements for conventional and renewable generation options. This study concluded that among renewable technologies, the PV life cycle required the smallest amount of land, and biomass the largest.[347] Ground-mounted PV systems in areas with high-quality solar resources had no greater requirements than coal-based fuel cycles, which require reclaiming mine lands and securing additional areas for waste disposal. A 2012 NREL report on renewables' land use called for more consistent methodologies to determine the relative impact among generation technologies.[348]

The direct land use for a natural gas power plant is smaller than that required for a coal-fired plant because large structures are not required for fuel storage or emission-control equipment.[349] The land-use footprint of a typical 555-MW NGCC power plant is estimated to use 20 acres, while a typical 360-MW gas turbine simple-cycle plant is estimated occupy roughly half as much land area. When the natural gas plants have equipment for carbon capture onsite, then the land-use requirements are estimated to increase by 10 percent.[350] Upstream, the direct land-use requirements—and potential ecological impacts—from natural gas production, transmission, and storage are more than an order of magnitude greater than the footprint of natural gas power plants.[351]

For example, shale gas development involves risks to water quality and quantity, as chemicals necessary for fracking might be leaked or spilled. Should leakage occur, "[t]he risks to local water resources will depend on the proximity to water bodies, the local geology, quantity and toxicity of the chemicals, and how quickly and effectively cleanup operations occur."[352] Induced seismicity by wastewater disposal for natural gas produced through hydraulic fracturing is also a concern.[353]

Upstream, coal mining is conducted both on the surface and underground, and often with significant impacts to the landscape and the ecosystem. Mountaintop mining and valley fills, for instance, can lead to large-scale landscape changes, including the loss of forested areas and displacement and loss of species, as well as significant alterations of stream ecosystems.[354] Similarly, the direct land use for a nuclear power plant is low, but environmental damage resulting from uranium mining—including acid mine drainage and the exposure of surrounding ecosystems to heavy metals[az]—is possible.[ba]

Although the upstream mining implications of renewable energy sources are less than those associated with many other generation sources, renewable energy systems also require a variety of materials, including commodities like iron/steel, polymer composites, aluminum, and rare earth minerals. Sourcing of these materials requires mining of raw materials, with associated risks related to toxicity of associated mine tailings and negative impacts on water used in resource extraction, separation, and processing.

DOE estimates that under a high wind-power deployment scenario by 2050, the total land area affected by wind-power installations would be less than 1.5 percent of the land area of the United States, with the majority (97 percent) of that land area remaining available for multiple purposes.[355] A 2015 Massachusetts Institute of Technology report estimated that all projected U.S. electricity demand in 2050 could be met by PV, assuming storage allowing for all kWh of electricity generated to be used; it would require roughly 33,000 km^2, or 0.4 percent of U.S. land area.[356] This is roughly equal to the area used by surface mining of coal and is less than the land area occupied by major roads. Fitting current existing U.S. rooftop area with PV could meet approximately 60 percent of the Nation's projected 2050 electricity needs.[357] Similarly, NREL estimated that the technical potential exists for rooftop PV to generate 1,432 TWh of electricity, or 39 percent of total annual electricity sales.[358]

Wildlife Impacts

Power generation can have adverse impacts on wildlife. There are a variety of mitigation strategies available to alleviate such impacts, and, as discussed below, mortalities attributed to power generation are significantly fewer than those than can be attributed to natural predators and collisions with buildings.

Available data on wildlife impacts associated with coal-fired power plant operations are limited, although one study[359] estimates that coal-fired power plants cause roughly the same or more avian mortalities per GWh generated than wind turbines. Factoring in projected climate change impacts, avian mortalities attributed to coal-fired electricity were estimated to be far greater than those attributed to other electric generation technologies.[360]

Nuclear power generation poses a risk to avian populations, which can be exposed to toxic waste ponds at uranium mining and milling facilities and collide with nuclear cooling towers.[361] Utility-scale solar energy development can affect birds and avian communities directly through fatality or indirectly through degradation, loss, or fragmentation of habitat. In general, direct fatalities are related to collisions or solar

[az] Uranium mining in the United States is regulated by the Atomic Energy Act of 1954, as amended (42 U.S.C. §§ 2011–2021, 2022–2286i, 2296a–2297h-13). These regulatory actions protect the health and safety of the public and the environment during the active life of a uranium recovery operation and after the facility has been decommissioned. Licensing may require licensees to take preventative measures prior to starting operations, including well tests, monitoring, and development of procedures that include excursion response measures and reporting requirements. NRC issued a "Generic Environmental Impact Statement for in situ Leach Uranium Mining Facilities" (NUREG 1910) in May 2009: http://www.nrc.gov/materials/uranium-recovery/geis.html.

[ba] The amount of uranium mining in the United States is currently very low.

flux.[bb, 362] Collisions may occur with all types of solar energy technologies, but solar flux effects on birds have been observed only at facilities with towers equipped to concentrate solar power. A recent study estimated that approximately 6,000 birds died across the 5 square miles of California's Ivanpah solar thermal facility last year;[363] none were endangered. For comparison, domestic cats kill 1.4 to 3.7 billion birds per year, and between 365 million to 988 million birds are estimated to die annually in the United States from building collisions.[364] The impacts on avian and bat populations are the principal ecological concerns associated with wind development for land-based wind projects. Effects on marine life are the principal concern for offshore wind.

DOE and the Bureau of Land Management (BLM) have jointly developed guidance to minimize environmental impacts—including impacts to wildlife—during the siting, construction, and operation of utility-scale solar facilities on public lands. BLM identified specific locations well suited for utility-scale production of solar energy that minimize wildlife impacts. Similarly, the DOE guidance integrates wildlife and environmental considerations into its analysis and selection of projects that it will financially support.[365]

Investments to develop cost-effective technologies that can reduce wildlife impacts are offering new avian deterrence technologies (e.g., tower coatings and ultrasonic transmitters) and mitigation techniques that will help minimize environmental impacts to sensitive wildlife in the future.[366]

The DOE "Wind Vision" report[367] finds that annual bird mortalities due to wind turbines (0.2 million birds/year) are much lower than those associated with other engineered structures and far lower than those killed by domestic cats. Most studies estimate the bat fatality rates due to wind turbines to be less than 10 bats/MW/study period.[368] With the increase in wind-power generation, the wind industry and regulatory agencies have worked to minimize the impacts of wind projects on migratory birds and other species of concern and their habitats.[bc]

Hydroelectric power can also significantly impact aquatic ecosystems, with fish and other organisms injured and killed by turbine passage. Mechanisms of mortality and injury are varied (e.g., strike, barotrauma,[bd] shear, turbulence). Reservoir water is usually more stagnant than normal river water, which can lead to algae blooms and other aquatic weeds crowding out native aquatic life. DOE has sponsored research to mitigate wildlife impacts of conventional hydropower (e.g., R&D of turbine designs that minimize fish deaths for fish that pass

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[bb] There is not a thorough understanding of potential impacts of solar facilities on avian species or the effectiveness of mitigation measures at this time. Consistency and standardization in avian monitoring and reporting protocols could be improved, and additional systematic data on avian fatalities are needed to decrease uncertainty about potential impacts. The preeminent report on this topic, published in 2015, calls for creating a solar-avian science plan to improve the scientific value of avian mortality data, inform decisions about project siting and design, and develop an avian risk assessment tool to improve understanding of impacts and inform project-specific mitigation decisions. Leroy J. Walston, Jr., Katherine E. Rollins, Karen P. Smith, Kirk E. LaGory, Karin Sinclair, Craig Turchi, Tim Wendelin, and Heidi Souder, *A Review of Avian Monitoring and Mitigation Information at Existing Utility-Scale Solar Facilities* (Argonne, IL: Argonne National Laboratory, April 2015), ANL/EVS-15/2, http://www.evs.anl.gov/downloads/ANL-EVS_15-2.pdf.

[bc] The Fish and Wildlife Service is one of the agencies responsible for this activity, and, in consultation with industry, it has acted to suggest design modifications for towers and to establish voluntary guidelines and guidance to protect bald and golden eagles, as well as the Indiana bat. See Fish and Wildlife Service, *Indiana Bat: Section 7 and Section 10 Guidance for Wind Energy Projects* (Fish and Wildlife Service, October 2011), http://www.fws.gov/midwest/endangered/mammals/inba/WindEnergyGuidance.html. DOE recently issued two funding opportunity announcements to develop mitigation technologies for eagles and bats. In December 2016, the Fish and Wildlife Service finalized a rule that revised its permitting processes and monitoring requirements to improve the protection of eagle populations. Changes to the rule "include revisions to permit issuance criteria, compensatory mitigation standards, criteria for eagle nest removal permits, permit application requirements, and fees." Laury Parramore, "Service Announces Final Rule to Further Conserve, Protect Eagles through Revised Permitting, Monitoring Requirements," Fish and Wildlife Service, December 14, 2016, https://www.fws.gov/news/ShowNews.cfm?ref=service-announces-final-rule-to-further-conserve-protect-eagles-through-&_ID=35912.

[bd] As a fish passes through a dam, it can experience barotrauma—significant changes in pressure that can result in internal injuries or death. Richard S. Brown, Alison H. Colotelo, Brett D. Pflugrath, Craig A. Boys, Lee J. Baumgartner, Z. Daniel Deng, Luiz G. M. Silva, et al., "Understanding Barotrauma in Fish Passing Hydro Structures: A Global Strategy for Sustainable Development of Water Resources," *Fisheries* 39, no. 3 (2014): 108–22, doi:10.1080/03632415.2014.883570.

through the turbine).[369] Many species of fish, such as salmon, swim from the sea upstream to spawn, and dams can block their way. Approaches like the construction of fish ladders and elevators help fish to move around dams to upstream spawning grounds. To address these challenges, the Federal Government is investing in tools and methods to develop, demonstrate, and validate environmentally and fish-friendly technologies, such as turbines that better allow for the downstream passage of fish and aerating turbines that will enable operators to better meet environmental standards while increasing electricity generation. Computational tools that estimate fish passage risk are also helping ensure that biological impact is considered during turbine design.[370]

Waste Impacts

Coal and nuclear power plants produce the largest amount of solid waste during generation. Coal combustion residuals (CCRs) are the second most abundant waste material in the United States after household waste.[371] CCRs are generally disposed onsite at the power plant, while some are used for beneficial purposes.[372] In 2014, U.S. plants produced 130 million tons of coal ash,[373] which is a byproduct of conventional coal-fired generation. Naturally occurring radioactive constituents, such as uranium, are also found in coal ash.[374, 375] Onsite coal ash impoundment ponds can breach, impacting surrounding ecosystems and watersheds—an issue that EPA continues to address through its rulemaking process.

Nuclear waste is stored at the reactor site where it is generated. In contrast, natural gas and oil generation produce limited amounts of chemical and air pollution control waste, and renewable technologies produce almost no waste during generation. Additional information on waste as it relates to decommissioning can be found later in this chapter.

Other Ecological Impacts

Additional ecological considerations for wind include impacts from associated infrastructure (e.g., roads, transmission lines, substations). Noise, visual impacts (from blinking lights and from wind turbines themselves), and property values are all concerns raised by communities with wind development. For onshore wind, a Lawrence Berkeley National Laboratory study found that there was no impact by wind turbines on residential property value.[376]

Ecosystem impacts from hydroelectric power plants depend on a river's size and flow rate; climate and habitat conditions; the type, size, design, and operation of the plant; and whether the plant is located upstream or downstream of other projects on the same river.[377] Most water-quality concerns have to do with how reservoirs affect oxygen levels downstream (since significant aeration occurs in process).

There are also ecological impacts associated with geothermal generation. When large amounts of geothermal fluids are withdrawn and injected below the earth's surface, induced seismicity becomes a concern. If induced seismicity occurs, it is typically less than magnitude 2.5 on the Richter scale (earthquakes usually are not felt below 3.5).[378]

To address concerns about induced seismicity related to enhanced geothermal systems, DOE commissioned experts to author the Induced Seismicity Protocol, a living guidance document for geothermal developers, public officials, regulators, and the general public that details useful steps to evaluate and manage the effects of induced seismicity related to geothermal projects.[379]

Land-Use and Ecological Impacts of Electricity T&D

While the environmental impacts of T&D tend to be smaller than generation impacts, they are not negligible.[380]As T&D assets are not large point sources of pollution and are geographically expansive, their impacts also may not be well characterized.[381] T&D systems have an array of direct and indirect environmental impacts, which can be divided between the impacts associated with construction and those related to operation of the electric grid. The ecological impacts of transmission lines can be weighed against transmission lines' benefits. For example, transmission lines connect remotely located, lower-emitting generation sources to load centers, and clearings for transmission lines create firebreaks, reducing the impacts of wild fires and improving emergency access.

New power lines, access roads, and associated equipment placed in undeveloped areas can create substantial environmental impacts, including the disturbance of forests, wetlands, and other natural areas. Adjusting proposed routes of overhead power lines can reduce environmental impacts.[382] Choosing a different type of pole structure or modifying construction methods can reduce environmental impacts. Right-of-way issues can be minimized by using corridor-sharing routes during the design phase.

Putting power lines underground can limit the visual impact of overhead lines. Burying low-voltage distribution lines is common in residential areas. Burying transmission lines, however, is uncommon because it is 2–10 times more expensive than building an overhead line.[383] T&D infrastructure requirements for DG systems have smaller footprints. DG units are closer to end users, reducing the need for new or expanded transmission. DG systems can require expanded transformer and substation capacities (the average cost of updating a substation is $40/kilovolt-ampere).

Avian mortalities from collisions with transmission lines and related infrastructures are an environmental cost of the T&D system. In addition to reducing bird populations, collisions and electrocutions can produce outages. Bird collisions vary by habitat type, species size, and scavenging rates, and they appear to be higher during migration. Adverse effects on certain birds (e.g., electrocution of eagles) may result in penalties.[384] One inventory of bird mortality from transmission lines across Canada, about half the size of the U.S. system, reported 2.5 to 25.6 million bird deaths annually.[385] In the United States, research conducted by the Fish and Wildlife Service found that power lines alone might kill up to 175 million birds annually.[386] Proactive planning can help reduce these impacts on avian and other wildlife populations.

Mitigation of Environmental Impacts

There are several existing environmental laws designed to help mitigate the environmental impacts and concerns outlined above. Applicable Federal laws include the CAA,[387] the Clean Water Act[388] and the Endangered Species Act.[389] Any Federal action involving new infrastructure requires the responsible Federal official to consider the potential environmental impacts of the proposed action and any reasonable alternatives.[390] This requirement is specified in the National Environmental Policy Act (NEPA) of 1969 and the Council on Environmental Quality Regulations for Implementing the Procedural Provisions of NEPA.[391] The complexity associated with obtaining the environmental permits necessary to build new infrastructure will differ depending on the implications of the proposed facility's proximity to sensitive air, water, wildlife, and cultural resources.

QER 1.1 found that while expanding T&D infrastructure can pose environmental challenges, building new infrastructure can also lead to significant net environmental benefits. For this reason, agencies across the Federal Government are engaged in several initiatives to modernize the Federal role in electric transmission permitting and project review.[392] In their analyses, permitting agencies typically[be] consider mitigation requirements that may be imposed as conditions to address unavoidable environmental harms. Decades of experience with siting energy T&D infrastructure have produced various methods for offsetting impacts to affected communities and ecosystems, including avoidance, minimization, and compensation. These methods are summarized in QER 1.1 and are reproduced in the box on the following page.

[be] Agencies must consider mitigation when completing an environmental impact statement, and mitigation is often considered when completing an environmental assessment.

Mitigating Environmental Impacts[bf]

- Mitigation is an important mechanism for agencies to use to avoid, minimize, rectify, reduce, or compensate the adverse environmental impacts associated with their activities.[bg, bh] Federal agencies typically rely upon mitigation to reduce environmental impacts through modification of proposed actions and consideration and development of mitigation alternatives during the National Environmental Policy Act process.[bi]
- Mitigation is important to Federal agencies managing public lands, which impose a responsibility to sustain an array of resources, values, and functions. For example, public lands contain important wildlife habitat and vegetative communities—in addition to recreational opportunities and ecosystem services, cultural resources, and special status species. These lands are managed for the use and enjoyment of present and future generations. The location, construction, and maintenance of energy infrastructure should avoid, minimize, and, in some cases, compensate for impacts to these public resources, values, and functions. Mitigation is of critical importance to agencies responsible for protecting the Nation's waters.[bj] Applying this mitigation hierarchy early in transmission and distribution infrastructure planning provides better outcomes for the impacted resources, values, and functions.[bk]
- Resource-specific mitigation measures can be applied to avoid or minimize impacts from a pipeline or an electric transmission project. In order to identify and implement appropriate mitigation measures, first the potential impacts of a project on a specific resource must be assessed. Then, project-specific and site-specific factors must be evaluated to determine whether the impact can be avoided or mitigated, what action can be taken, how effective the mitigation measure will be, and the cost effectiveness of the measure.

[bf] Department of Energy (DOE), Office of Energy Policy and Systems Analysis (EPSA), *Quadrennial Energy Review First Installment: Energy Transmission, Storage, and Distribution Infrastructure* (Washington, DC: DOE-EPSA, 2015), 7-6, http://www.energy.gov/epsa/quadrennial-energy-review-first-installment.

[bg] 40 C.F.R. § 1508.20 (1978).

[bh] "Section 404 of the Clean Water Act: Policy and Guidance," Environmental Protection Agency, accessed March 9, 2015, http://water.epa.gov/lawsregs/guidance/wetlands/ wetlandsmitigation_index.cfm.

[bi] The Council on Environmental Quality's NEPA regulations require agencies to identify in their Record of Decision any mitigation measures that are necessary to minimize environmental harm from the alternative selected (40 C.F.R. § 1505.2(c)). The NEPA analysis can also consider mitigation as an integral element in the design of the proposed action. The regulations further state that a monitoring and enforcement program shall be adopted where applicable for any mitigation (40 C.F.R. § 1505.2(c)).

[bj] Compensatory Mitigation for Losses of Aquatic Resources, 73 Fed. Reg. 19594 (April 10, 2008) (40 C.F.R. § 230), https://www.gpo.gov/fdsys/pkg/FR-2008-04-10/pdf/E8-6918.pdf.

[bk] Department of the Interior, Bureau of Land Management, "Instruction Memorandum No. 2013-142 – Interim Policy, Draft – Regional Mitigation Manual Section – 1794," June 13, 2013, https://www.blm.gov/wo/st/en/info/regulations/Instruction_Memos_and_Bulletins/national_instruction/2013/IM_2013-142.html; Joel P. Clement, Alletta d'A. Belin, Michael J. Bean, Ted A. Boling, and James R. Lyons, *A Strategy for Improving the Mitigation Policies and Practices of the Department of the Interior* (Department of the Interior, Energy and Climate Change Task Force, April 2014), www.doi.gov/news/upload/Mitigation-Report-to-the-Secretary_FINAL_04_08_14.pdf; "The BLM's Landscape Approach for Managing Public Lands," Department of the Interior, Bureau of Land Management, last modified February 11, 2016, http://www.blm.gov/wo/st/en/prog/more/Landscape_Approach.html; NiSource, Inc., Record of Decision, Habitat Conservation Plan, Environmental Impact Statement, and Permit Issuance, 78 Fed. Reg. 68465 (November 14, 2013), http://www.gpo.gov/fdsys/pkg/FR-2013-11-14/pdf/2013-27230.pdf.

jurisdictions and with a wide range of stakeholders, is uniquely challenging. Federalism and the interplay of state and Federal law create overlapping jurisdictional lines. State, local, and tribal governments, assisted by Federal agencies, need to build capacity to minimize safety and security consequences, as well as protect the environment, while limiting permitting-related delays.[393, 394] Local governments may adopt zoning requirements that differ from state regulations or even the regulations of neighboring communities.[395] Tribal governments become participants in permitting decisions if a project may disrupt cultural or historic properties or resources.[396]

For any project that involves a Federal action (e.g., if a proposed project would be sited on Federal land or partially financed with Federal funds), the responsible Federal agency is required by NEPA to evaluate potential social and environmental impacts of the proposed action and consider reasonable alternatives.[397] Since multiple Federal agencies can be involved with permitting T&D infrastructure, the Obama Administration has taken steps to modernize Federal permitting and review processes.[398] Active coordination between Federal, state, and local governments enables well-informed decision making, striking a fair balance between a broad range of public and private interests.

Federal and State Initiatives to Modernize Permitting and Review Processes

The Federal Government is undertaking several actions to reduce the aggregate permitting and review time for infrastructure projects, while improving environmental and community outcomes. This includes a number of Federal and regional initiatives (outlined in Table 3-6) that are designed to support better decision making in the following ways:

- Facilitate better coordination between permitting authorities at all levels of government
- Develop and publish relevant information, data, and tools
- Support infrastructure planning and establish rights-of-way for energy projects
- Conduct technology R&D.

Table 3-6. Federal and Subnational Initiatives to Modernize Electric Infrastructure Permitting and Review Processes[399]

Initiative Title	Description (Scope and Specific Focus Areas)
Facilitate Better Coordination between Permitting Authorities, Increase Transparency	
Establishing an Implementation Plan to Modernize Permitting	National; Federal plan includes four strategies, 15 reforms, and nearly 100 near-term and long-term milestones, established by Presidential Memorandum
Improving Performance of Federal Permitting and Review of Infrastructure Projects	National; Executive Order 13604 to improve the efficiency and transparency of permitting and review processes for infrastructure projects while producing measurably better outcomes for communities and the environment
Transforming the Nation's Electric Grid through Improved Siting, Permitting, and Review	National; developing an integrated interagency pre-application process for significant onshore electric transmission projects requiring Federal approval, identifying and designating energy corridor
Creating a Permitting Dashboard	National; online database to track the status of Federal environmental reviews and authorizations for projects covered under Title 41 of the FAST Act
Establishing an Interagency Rapid Response Team for Transmission	National; improve Federal interagency coordination, tribal consultation, and conflict resolution for challenging transmission projects

Initiative Title	Description (Scope and Specific Focus Areas)
The Western Governors Association Regulatory and Permitting Information Desktop Toolkit	Western United States; includes wiki platform for stakeholder and agency collaboration
Integrated Interagency Pre-Application Process	National; DOE final rulemaking to improve project planning process
Fixing America's Surface Transportation Act (FAST Act)	National; Title 41 establishes the Federal Infrastructure Permitting Improvement Steering Council to inventory major infrastructure projects that are subject to NEPA and to improve the review process
Publish Information, Data, and Tools	
EPA's NEPAssist	National; web-based mapping tool
Fish and Wildlife Service's Information, Planning, and Conservation Tool	National; helps identify endangered and threatened species before beginning project design
Army Corps' Federal Support Toolbox	National; "one-stop shop" online water resources data portal
Eastern Interconnection States Planning Council's Energy Zones Mapping Tool	Eastern United States; includes 273 geographic information system data layers and links to key resources
Western Electricity Coordinating Council Environmental Data Viewer	Western United States; interactive transmission planning tool
Support Infrastructure Planning	
Undertaking landscape- and watershed-level mitigation and conservation planning	National; environmental mitigation and resource protection at the landscape and watershed levels
Speeding Infrastructure Development through more Efficient and Effective Permitting and Environmental Review	National; Presidential Memorandum calling for expedited review of priority projects and improved accountability, transparency, and efficiency
Memorandum of Understanding regarding transmission siting on Federal lands	National; aims at reducing approval time and reducing barriers to siting new transmission lines
Designating Corridors for Pipelines, Electric Transmission Lines, and Related Infrastructure on Federal lands	National; Energy Policy Act of 2005 Section 368 establishes rights-of-way designated on western Federal lands and considered for all other states.
Desert Renewable Energy Conservation Plan	California; Federal and state collaboration on landscape-level plan streamlining renewable development while conserving unique and valuable desert ecosystems
Technology research and development	
Grid Modernization Initiative, DOE	National; enhances security capabilities and stakeholder support

A number of Federal and regional initiatives are designed to improve the electric infrastructure permitting and review process. Improved coordination not only reduces permitting and review time, but also improves environmental and community outcomes. These initiatives include the facilitation of coordination between authorities as well as increased transparency, new tools to disseminate information effectively, the support of infrastructure planning, and technology R&D.

Addressing Impacts of Increased Deployment and New Clean Energy Technologies

Increased deployment of existing clean energy technologies and the development of new clean energy technologies will require refinement of existing mitigation policies, which were developed before these technologies became available, as well as new approaches to mitigation. Including analyses of land-use and ecological impacts in the R&D process for new technologies could avoid most impacts and decrease the need for mitigation.

Improving environmental outcomes from infrastructure siting requires the joint efforts of agencies at all levels of government and the private sector.

Recent Transmission Line Approvals

- Plains & Eastern Clean Line Project:[bl] In March 2016, Secretary Moniz announced that the Department of Energy (DOE) would participate in the development of the Plains & Eastern Clean Line (Clean Line) project, a major clean energy infrastructure project. The Clean Line project taps abundant, low-cost wind generation resources in the Oklahoma and Texas panhandle regions to deliver up to 4,000 megawatts (MW) of wind power via a 705-mile direct current (DC) transmission line—enough energy to power more than 1.5 million homes in the mid-South and Southeast United States.

  The Clean Line project will include a 500-MW converter station in Arkansas that will allow the state to access the low-cost renewable energy supplied from the project. Currently, Arkansas has no utility-scale wind generation facilities and none under construction. Furthermore, as a condition of its participation, DOE requires that Clean Line make payments to localities for any otherwise-taxable land and assets that are owned by the Federal Government.
- Great Northern Transmission Line:[bm] In November 2016, DOE announced the issuance of a Record of Decision and Presidential Permit for the Great Northern Transmission Line. The 224-mile, overhead alternating current transmission line will bring up to 883 MW of hydropower from Manitoba Power in Canada to Grand Rapids, Minnesota, and will deliver wind power generated in North Dakota to Manitoba Power in Canada. The project has the potential to provide enough reliable, affordable, and carbon-free electricity to serve approximately 600,000 residential customers in the Upper Midwest.
- New England Clean Power Link:[bn] In December 2016, DOE announced the issuance of a Record of Decision and Presidential Permit for the New England Clean Power Link Transmission Line. The 154-mile underground and underwater DC transmission line will bring up to 1,000 MW of hydropower from Quebec, Canada, to southern Vermont. The project has the potential to provide enough reliable, affordable, and carbon-free electricity to serve approximately 1 million residential customers in New England.

[bl] "Plains & Eastern EIS," Department of Energy, accessed December 19, 2016, http://www.plainsandeasterneis.com/.
[bm] "Great Northern Transmission Line EIS," Department of Energy, accessed December 19, 2016, http://www.greatnortherneis.org/.
[bn] "New England Clean Power Line Project," Department of Energy, accessed December 19, 2016, http://necplinkeis.com/.

Data and Analytical Needs for a Clean Electricity System

In general, it is important to have authoritative, unbiased data in order to make informed Federal policy decisions, but these data are also important to empower other public- and private-sector entities at all levels to identify cost savings, provide better services, effectively plan for the future, make research and scientific discoveries, etc. DOE has done well to provide relevant electricity data for many years, most notably via the Energy Information Administration. However, attempts to address a host of emerging issues and pursue key policy objectives in the electricity sector have uncovered data issues that are inhibiting such efforts by actors at all levels of government.

Ecological and other environmental impacts, specifically, can be reduced by improving availability, quality, harmonization, standardization, and accessibility of relevant data to inform decision making. Some data sets exist already, including Tethys,[400] a growing compendium of information and data exchanges on the environmental effects of wind and marine renewable energy technologies,[401] and the Wind-Wildlife Impacts Literature Database, a searchable document collection focusing on the impacts to wildlife from a variety of technologies.[402] However, relevant data, if available, can be plagued with quality issues, and there are often spatial and temporal disparities between related data sets that make analysis difficult.

There is a need for additional data and analytical tools on updated life-cycle analysis using consistent methodologies, as well as studies that attempt to monetize external costs[403] associated with land-use requirements and ecological impacts. More research and increased availability of data would improve the transparency of environmental impacts to developers, regulators, and the public, and help inform more effective strategies for mitigating ecological impacts of electricity infrastructure and operations.

Including analysis of land and ecosystems in the R&D process could decrease the need for mitigation. New technologies with no adverse effects on ecosystems would unlock further areas where that technology could be deployed. As the United States and other countries accelerate clean energy innovation through Mission Innovation, including land-use and ecosystem impacts in Mission Innovation could provide a more holistic assessment of the environmental and ecological effects of new clean energy technologies.

Multiple Uses for Rights-of-Way: Repowering and Repurposing Degraded Lands or Brownfields

Electricity infrastructure can be sited at less environmentally sensitive locations, such as Superfund sites, brownfields, landfills, abandoned mining land, or existing transportation and transmission corridors. Through its cataloging of Federal and state tracked contaminated lands, landfills, and mine sites, EPA has identified thousands of potential sites that could potentially ameliorate incremental environmental impacts.[404] Comprehensive land-use planning exercises have also identified areas appropriate for development, such as the California Desert Renewable Energy Conservation Plan and the DOE-BLM Solar Programmatic Environmental Impact Statement (PEIS). States and Federal agencies could assess the amount of land suitable for multiple simultaneous uses, including the installment of clean energy technologies. Zoning laws could allow multiple land uses as a factor in permitting decisions for clean energy technologies.

Programmatic Environmental Planning and Landscape-Scale Impact Assessments

The trend has been to consider mitigation through PEIS and landscape-scale impact assessment, replacing a more project-orientated focus. A November 2013 Presidential Memorandum outlined further mitigation principles for Federal agencies, including requiring agencies to set a “no net loss” or “net benefit” goal. Subsequent Department of the Interior guidance on landscape-scale mitigation supported examining project impacts by considering the range of the resource in the context of the larger landscape where the project would be built. Landscape-scale strategies consider impacts across ecosystems and administrative boundaries, and give a more comprehensive picture than studies focused narrowly on impacts on a project-by-project basis. This approach is being applied to a variety of major infrastructure development projects, including transmission and other electricity projects. The Fish and Wildlife Service uses landscape-scale analysis to protect the golden eagle, among other species, defining its "no net loss" policy to require every golden eagle killed at a wind plant to be offset by reducing eagle mortality from another source or by increasing eagle productivity.[405]

BLM also conducts PEIS for geothermal explorations or solar energy development in six southwestern states. PEIS evaluate environmental impacts of a variety of individual projects over a long time frame and a large geographic area.[406] Land-use and ecological impacts of energy technologies should be assessed on a larger scale, and the necessary cooperation across jurisdictions should be expanded, especially as impacts on wildlife could be felt far away from the original site of the deployed technology.

Electricity and Environmental Justice

Populations of concern—including low-income communities and some minority and tribal communities—are more vulnerable to the air- and water-quality impacts of the electricity system. These communities are also disproportionately vulnerable and less resilient to the impacts of climate change. These communities may have greater exposures due to their proximity to sources of pollution; may be inherently more sensitive to environmental impacts of pollution due to higher baseline risks, such as poor overall health; and typically have lower capacity to adapt to the impacts of pollution and extreme weather.[407] For example, a greater percentage of minorities and people living below the poverty level live within a 3-mile radius of coal- and oil-fired power plants, compared to the U.S. population overall.[408] Additionally, existing health disparities and other inequities in these communities increase their vulnerability to the health effects of degraded air quality and climate change.[409]

Populations with the greatest sensitivity to the impacts of air pollution from power generation include children, the elderly, African Americans, and women.[410] Several factors make children more sensitive to air-quality impacts, including lung development that continues through adolescence, the size of children's airways, their level of physical activity, and body weight. Ground-level ozone and PM are associated with increased asthma episodes and other adverse respiratory effects in children.[411] Minority adults and children bear a disproportionate burden associated with asthma, as measured by emergency hospital visits, lost work and school days, and overall poorer health status.[412]

Environmental justice concerns have been addressed in recent regulatory actions affecting power plant emissions, wastewater discharges, and onsite solid waste impoundment.[413, 414, 415] In many cases, these rulemakings have provided the opportunity to reduce existing disparities in health impacts. For example, the Mercury and Air Toxics Standards require power plants to limit their emissions of toxic air pollutants like mercury, arsenic, and metals, which disproportionately impact certain communities. In addition, Executive Order 12898 requires Federal agencies to consider environmental justice in regulatory, permitting, and enforcement activities. Also, in developing the CPP, EPA took steps to ensure that vulnerable communities were not disproportionately impacted by the rule and that the rule's benefits, including climate benefits and air-quality improvements, were distributed fairly.

The Federal Interagency Working Group on Environmental Justice's "Promising Practices for EJ Methodologies in NEPA Reviews"[416] contains successful ideas across nine areas, from which all Federal agencies can draw to develop their approaches to address environmental justice in the NEPA process:

- Meaningful engagement
- Scoping process
- Defining the affected environment
- Developing and selecting alternatives

- Identifying minority populations
- Identifying low-income populations
- Impacts analysis
- Disproportionately high and adverse impacts
- Mitigation and monitoring.

Decommissioning of Generation Assets

Infrastructure expansion can improve environmental performance by replacing higher-polluting with lower-polluting technologies.[417] Because of their unique environmental concerns, nuclear power plants have strict, mandatory guidelines, payment processes, and monitoring for decommissioning activities, while in general, other generation assets do not. There are multiple ways to improve and expedite end-of-life-cycle processes while also improving environmental and societal outcomes.

Currently, the changing electricity sector is causing the closure of many coal and nuclear plants in a shift from recent trends. From 2000 through 2009, power plant retirements were dominated by natural gas steam turbines. Over the past 6 years (2010–2015), power plant retirements were dominated by coal plants (37 GW), which accounted for over 52 percent of recently retired power plant capacity.[418] Over the next 5 years (between 2016 and 2020), 34.4 GW of summer capacity is planned to be retired, and 79 percent of this planned retirement capacity are coal and natural gas plants (49 percent and 30 percent, respectively). The next largest set of planned retirements are nuclear plants (15 percent).[bo, 419] A much smaller percentage of planned retirements are diesel combustion and oil steam turbines. These are less prominent in planned retirements, in part because they now represent a much smaller percentage of the Nation's electricity capacity than has historically been the case.

During decommissioning, all plants have waste streams that need to be managed. Coal and nuclear power plants produce the largest amount of solid waste during generation. For coal plants, the most expensive part of decommissioning in many cases will be environmental remediation of the CCR disposal sites.[420] Nuclear waste is stored at the reactor site where it is generated. The lack of a centralized permanent waste disposal facility for nuclear waste means that spent fuel storage facilities require continued management after a plant has been decommissioned. Decommissioning needs will continue to evolve as new generators, especially non-hydro renewables, reach the end of their operating lives in the next 20–30 years. These plants have some unique waste streams, including large volumes of glass and aluminum, large fiberglass blades, and in some cases, rare earth metals; however, there is a high potential for recycling some of these materials, and wind plants often have the opportunity for repowering by upgrading the turbine.

Coal

Increases in coal retirements imply a greater need for decommissioning these plants. The coal ash byproduct of conventional coal-fired power plants is the largest quantity of solid waste produced from the generation of electricity.[421] The composition and quantity of this solid waste depends on the type of coal burned, the power conversion technology used, and the addition of environmental controls. Decommissioning needs include (1) data on waste and decommissioning costs; (2) development of coal plant decommissioning procedures; and (3) identification of barriers to waste recycling and options for overcoming these barriers.

[bo] These totals are based on announced retirements as of October 2016. Pending state action may prevent six nuclear reactors from retiring, and another reactor has since announced it will retire during this time frame.

Nuclear Power

NRC operating licenses for approximately 60 percent of the existing nuclear-power generating units in the United States will expire by 2040. Without further license extensions, these expirations could result in retirements and decommissioning wastes in the coming decades.[422] Nuclear plant owners must provide NRC with detailed decommissioning plans and periodic updates on the status of their decommissioning fund for the nuclear reactors they own.[423] Three of the paramount considerations when developing a decommissioning plan are the radiological contamination, condition, and configuration of the plant. Two decommissioning methods have been used in the United States: Safe Enclosure ("SAFSTOR") and Immediate Dismantling ("DECON").[424] In DECON, the plant is immediately dismantled, and the site is prepped for reuse by removing nuclear waste in casks for storage. In SAFSTOR decommissioning, plant dismantling is deferred for about 50 years. There is currently no centralized permanent disposal facility for commercial used nuclear fuel in the United States, so this radioactive material is stored at reactor sites in 35 states awaiting construction of a permanent handling facility.[425]

Oil and Gas

Unlike coal plants and nuclear reactors, gas- and oil-fired plants do not generate combustion ash or nuclear waste. The unique solid waste concerns for gas- and oil-fired plants are the byproducts from emission controls. However, the solid waste from electricity generation is small because of the low adoption rate of these emission controls for gas- and oil-fired plants. These solid wastes are similar to the waste generated by environmental controls placed on the stacks of coal plants, especially for most post-combustion removal technology.

There are three methods for decommissioning an oil or gas plant, considering the conditions of the plants and the total budget: cold closure, selective demolition, or total demolition.[426] The decommissioning of gas and oil power plants creates construction and demolition waste, general refuse, and chemical waste.[427]

Chemical waste that is particular to oil and gas plants includes naturally occurring radioactive materials (NORM). During the oil and gas combustion process, because NORM are not volatile, burning away the carbon leads to higher levels of radioactive waste in scale, sludge, and scrapings of the generator, tanks, and pipelines.[428] Radioactive material can also form a thin film on the interior surfaces of gas processing equipment and vessels. Currently, no Federal regulations exist that specifically address the handling and disposal of NORM wastes. However, several oil-producing states (Texas, Louisiana, New Mexico, North Dakota, and Mississippi) have enacted specific NORM regulations.[429]

Hydropower

There are two options for decommissioning a hydropower plant. A partial retirement involves retirement of only the hydroelectric facilities and retains portions of the dam and other structures. Some rehabilitation of the structure for safety or maintenance may be required and can include reduction in height or breach of the dam. In this case, the dam is either reduced or eliminated, while some of the ancillary facilities may remain intact. A full retirement includes the removal of the project and all appurtenant structures, including rehabilitation or restoration of the affected project area. Decommissioning (whether partial or full) generally requires completion of an environmental impact statement, and every dam removal process will have site-specific engineering, environmental, and community issues.

Wind

To date, there have not been many wind decommissioning projects. As a result, details of decommissioning wind projects are very limited. In some states, developers are required to have decommissioning process and cost estimates ready with the decommissioning plan. In general, the decommissioning process of a wind plant consists of removing the turbine, destroying the concrete pads, restoring the surface, and replanting and rebuilding the soil of disturbed land. Communication towers are taken apart, removed, and then either disposed of, recycled, or reused.[430]

Solar PV

Like wind, there have not been many decommissioning projects for solar to date. During decommissioning, PV modules must be removed from racks, and the racks must be dismantled. These are stored temporarily onsite until they are transferred by trucks to appropriate facilities, like recycling sites, or back to the manufacturer. Similarly, inverters and associated components must be transported to an appropriate site per local, state, and Federal waste-disposal regulations. Finally, re-vegetation of the site is done to minimize erosion and disruption of vegetation. In the case of one solar farm decommissioning, the recycling value of the raw material for the solar array is expected to exceed the removal costs and provide a net economic benefit.[431]

While there is no industry-wide requirement for solar and wind developers to develop and fund decommissioning plans, BLM does impose decommissioning requirements on Federal lands. BLM requires developers seeking to site renewable generation projects on Federal lands to file a decommissioning plan and post a performance bond to help fund site remediation. The performance bond is intended to cover costs associated with (1) removing hazardous materials, including "herbicide use, petroleum-based fluids, and dust control or soil stabilization materials"; (2) decommissioning, removing, and properly disposing of all "surface facilities," such as panels; and (3) "addressing reclamation, revegetation, restoration, and soil stabilization," such as regrading or vegetation, as required under the Clean Water Act.[432] Thus, solar and wind facilities sited on Federal lands must have a decommissioning plan before they are granted right-of-way and must post a bond to fund decommissioning.

The recommendations based on the analysis in this chapter are covered in Chapter VII (*A 21st-Century Electricity System: Conclusions and Recommendations*).

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Chapter IV

ENSURING ELECTRICITY SYSTEM RELIABILITY, SECURITY, AND RESILIENCE

This chapter addresses a range of possible risks to the electricity system and the broader economy, and it suggests options to mitigate and prepare for these risks. The first section explores the changing nature of reliability—the ability of the system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system components—in the future electricity system. The next section examines existing and growing vulnerabilities for the electricity system and opportunities to address these vulnerabilities, including cybersecurity risks, interdependency of electricity with other critical infrastructures, and increased risk due to worsening global climate change. The final section focuses on enhancing the resilience of the system to minimize disruptions of service and return rapidly to normal operations following adverse events.

FINDINGS IN BRIEF:
Ensuring Electricity System Reliability, Security, and Resilience

- The reliability of the electric system underpins virtually every sector of the modern U.S. economy. Reliability of the grid is a growing and essential component of national security. Standard definitions of reliability have focused on the frequency, duration, and extent of power outages. With the advent of more two-way flows of information and electricity—communication across the entire system from generation to end use, controllable loads, more variable generation, and new technologies such as storage and advanced meters—reliability needs are changing, and reliability definitions and metrics must evolve accordingly.
- The time scales of power balancing have shifted from daily to hourly, minute, second-to-second, or millisecond-to-millisecond at the distribution end of the supply chain, with the potential to impact system frequency and inertia and/or transmission congestion. The demands of the modern electricity system have required, and will increasingly require, innovation in technologies (e.g., inverters), markets (e.g., capacity markets), and system operations (e.g., balancing authorities).
- Electricity outages disproportionately stem from disruptions on the distribution system (over 90 percent of electric power interruptions), both in terms of the duration and frequency of outages, which are largely due to weather-related events. Damage to the transmission system, while infrequent, can result in more widespread major power outages that affect large numbers of customers with significant economic consequences.
- As transmission and distribution system design and operations become more data intensive, complex, and interconnected, the demand for visibility across the continuum of electricity delivery has expanded across temporal variations, price signals, new technology costs and performance characteristics, social-economic impacts, and others. However, deployment and dissemination of innovative visibility technologies face multiple barriers that can differ by the technology and the role each plays in the electricity delivery system.
- Data analysis is an important aspect of today's grid management, but the granularity, speed, and sophistication of operator analytics will need to increase, and distribution- and transmission-level planning will need to be integrated.
- The leading cause of power outages in the United States is extreme weather, including heat waves, blizzards, thunderstorms, and hurricanes. Events with severe consequences are becoming more frequent and intense due to climate change, and these events have been the principal contributors to an observed increase in the frequency and duration of power outages in the United States.
- Grid owners and operators are required to manage risks from a broad and growing range of threats. These threats can impact almost any part of the grid (e.g., physical attacks), but some vary by geographic location and time of year. Near-term and long-term risk management is increasingly critical to the ongoing reliability of the electricity system.
- The current cybersecurity landscape is characterized by rapidly evolving threats and vulnerabilities, juxtaposed against the slower-moving deployment of defense measures. Mitigation and response to cyber threats are hampered by inadequate information-sharing processes between government and industry, the lack of security-specific technological and workforce resources, and challenges associated with multi-jurisdictional threats and consequences. System planning must evolve to meet the need for rapid response to system disturbances.
- Other risk factors stem from the increasing interdependency of electric and natural gas systems, as natural gas–fired generation provides an increasing share of electricity. However, coordinated long-term planning across natural gas and electricity can be challenging because the two industries are organized and regulated differently.
- As distributed energy resources become more prevalent and sophisticated—from rooftop solar installations, to applications for managing building electricity usage—planners, system operators, and regulators must adapt to the need for an order of magnitude increase in the quantity and frequency of data to ensure the continuous balance of generation and load.

FINDINGS IN BRIEF:
Ensuring Electricity System Reliability, Security, and Resilience (continued)

- Demand response and flexibility technologies—such as hydropower and storage—offer particularly flexible grid resources that can improve system reliability, reduce the need for capital investments to meet peak demand, reduce electricity market prices, and improve the integration of variable renewable energy resources. These resources can be used for load reduction, load shaping, and consumption management to help grid operators mitigate the impact of variable and distributed generation on the transmission and distribution systems.
- Information and communications technologies are increasingly utilized throughout the electric system and behind the meter. These technologies offer advantages in terms of efficient and resilient grid operations, as well as opportunities for consumers to interact with the electricity system in new ways. They also expand the grid's vulnerability to cyber attacks by offering new vectors for intrusions and attacks—making cybersecurity a system-wide concern.
- There are no commonly used metrics for measuring grid resilience. Several resilience metrics and measures have been proposed; however, there has been no coordinated industry or government initiative to develop a consensus on or implement standardized resilience metrics.
- Low-income and minority communities are disproportionately impacted by disaster-related damage to critical infrastructure. These communities with fewer resources may not have the means to mitigate or adapt to natural disasters, and they disproportionately rely on public services, including community shelters, during disasters.
- This chapter was developed in conjunction with the closely related and recently published "Joint United States-Canada Electric Grid Security and Resilience Strategy."

Reliability, Resilience, and Security: Grid Management and Transformation

Traditional electricity system operations are evolving in ways that could enable a more dynamic and integrated grid. The growing interconnectedness of the grid's energy, communications, and data flow creates enormous opportunities; at the same time, it creates the potential for a new set of risks and vulnerabilities. Also, the emerging threat environment—particularly with respect to cybersecurity and increases in the severity of extreme weather events—poses challenges for the reliability, security, and resilience of the electricity sector, as well as to its traditional governance and regulatory regimes.

The concepts of reliability, security, and resilience are interrelated and considered from different perspectives. Meeting consumer expectations of reliability is a fundamental delivery requirement for electric utilities, where reliability is formally defined through metrics describing power availability or outage duration, frequency, and extent. The utility industry typically manages system reliability through redundancy and risk-management strategies to prevent disruptions from reasonably expected hazards.

Grid Reliability, Security, and Resilience

- For purposes of this discussion, *reliability* is the ability of the system or its components to withstand instability, uncontrolled events, cascading failures, or unanticipated loss of system components. *Resilience* is the ability of a system or its components to adapt to changing conditions and withstand and rapidly recover from disruptions. *Security* refers specifically to the ability of a system or its components to withstand attacks (including physical and cyber incidents) on its integrity and operations.

Delivery of electricity service has been consistently and highly reliable for most of the century-long development, expansion, and continuous operation of grids across all regions of the Nation. The traditional definition of reliability—based on the frequency, duration, and extent of power outages—may be insufficient to ensure system integrity and available electric power in the face of climate change, natural hazards, physical attacks, cyber threats, and other intentional or accidental damage; the security of the system, particularly cybersecurity, is a growing concern.

Resilience is the ability to prepare for and adapt to changing conditions, as well as the ability to withstand and recover rapidly from disruptions, whether deliberate, accidental, or naturally occurring.[1] While resilience is related to aspects of both reliability and security, it incorporates a dynamic response capability to reduce the magnitude and duration of energy service disruptions under stressful conditions.[2] Infrastructure planning and investment strategies that account for resilience typically broaden the range of risk-reduction options and improve national flexibility through activities both pre- and post-disruption, while also focusing on the electricity-delivery outcomes for the consumer.

U.S. policies, markets, and institutional arrangements must evolve to reflect new electricity system realities and trends—continuing to enable and enhance the reliability, security, and resilience of the electric grid. The Department of Energy (DOE), the Federal Energy Regulatory Commission (FERC), the North American Electric Reliability Corporation (NERC), regional planning authorities, utilities, power system operators, states, and other organizations work together to ensure the reliability of the U.S. power system through the implementation of reliability standards, timely planning and investment, and effective system operations and coordination.

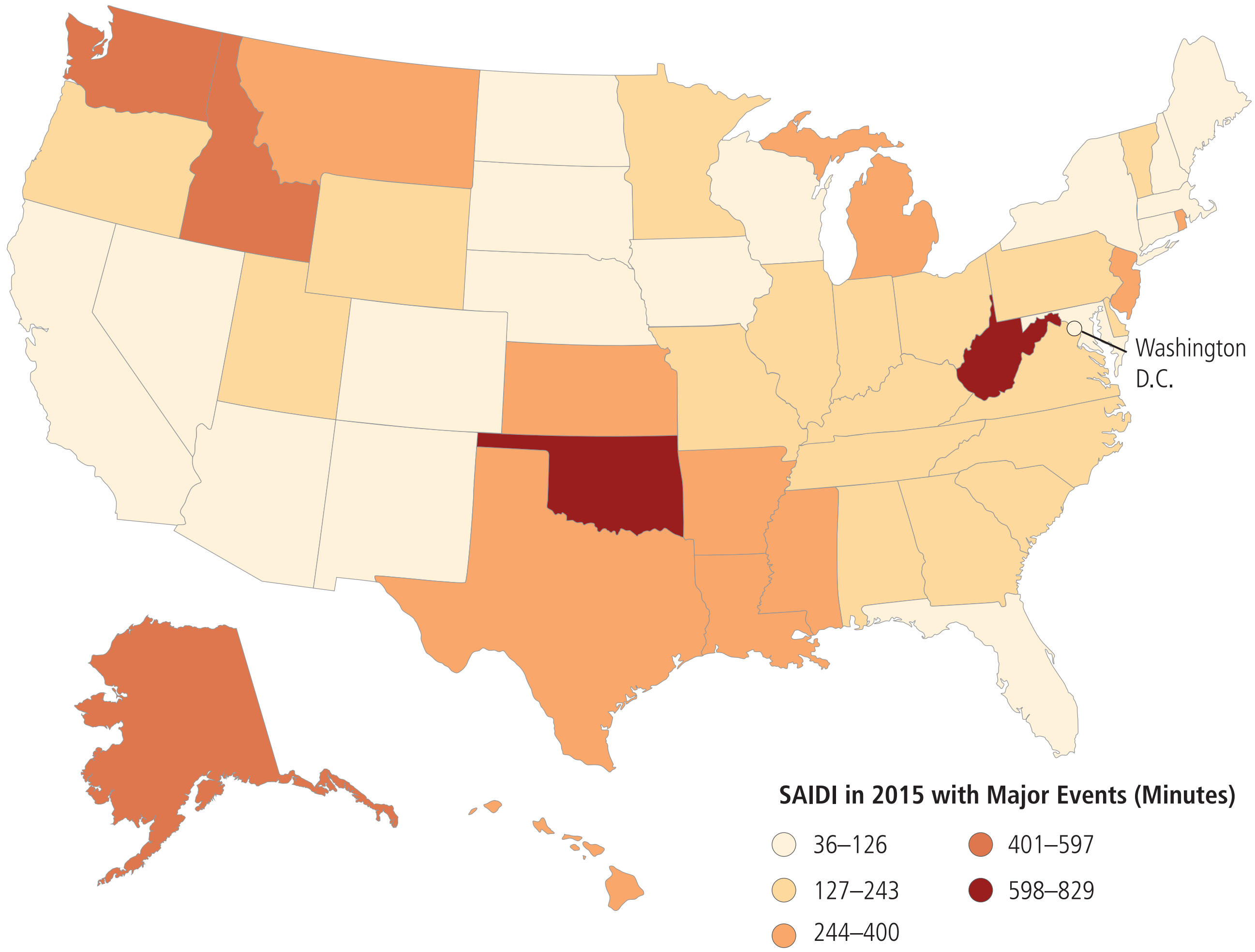
The Changing Nature of Reliability

Electricity customers have high expectations of electricity reliability from their utility providers. Virtually every sector of the modern U.S. economy depends on electricity—from food production, to banking, to health care. Critical infrastructures like oil, gas, transportation, and water all depend on electricity, and the electric system depends on them. This places a high premium on reliability.

Standard Measures of Reliability

A brief review of how reliability is measured today will help define the playing field and the associated value at stake. From the utility industry perspective, reliability is formally defined through metrics describing power availability or outage duration, frequency, and extent. Reliability within the utility industry is managed to ensure the system operates within limits and avoids instabilities or the growth of disturbances. These practices are not static, and utilities continue to improve their reliability practices and implementation methods to reflect increased consumer expectations. Typical approaches to reliability include hardening, investment, and redundancy to prevent disruptions from reasonably expected hazards.

Figure 4-1. System Average Interruption Duration Index by State, 2015[3]



States experienced varying levels of reliability in 2015. A reliable bulk power system does not necessarily mean reliable end-user electricity service because outages often originate on local distribution systems, as reflected in the SAIDI measurements in the above map.

Most state and Federal regulators have significant experience addressing system reliability and currently consider the issues of resilience and security through the lens of existing reliability tools, approaches, and metrics. One metric applied with the goal of improving system performance with respect to reliability indicators is the System Average Interruption Duration Index (SAIDI). SAIDI measures the total duration of an interruption for the average customer given a defined time period. Typically, it is calculated on a monthly or yearly basis. Another metric, the Customer Average Interruption Duration Index (CAIDI), measures how long it takes to restore the system once an outage occurs. And, the System Average Interruption Frequency Index (SAIFI) measures the average number of times that a customer experiences an outage during the year. SAIFI is calculated by dividing SAIDI by CAIDI. As most outages occur on the distribution system rather than the bulk power system, these reliability indices are commonly used to measure distribution level reliability. NERC uses a number of bulk power system reliability indices.[4]

Based on these reliability measures, the average customer experiences 198 minutes of electric power unavailability per year,[a, 5] although there is significant variability among states and utility providers. The best-

[a] Analysis is based on 2016 Energy Information Administration (EIA) data. Information reported to EIA is estimated to cover approximately 90 percent of electricity customers.

performing state had a SAIDI level of 85 minutes a year. In contrast, as shown in Figure 4-1, one state had a SAIDI statistic in 2015 of nearly 14 hours of outage for the year, with an availability level of 99.84 percent. Even this state level of aggregation masks some outliers in the data. There were several utilities with a SAIDI index below 1 minute of outage for the year.

There are, however, caveats to these findings. First, the variability of reliability performance is a function of a myriad of factors, including regional differences, varying regulatory standards, costs, system configuration, customer density, hazard exposure, and other. Also, utilities have historically reported SAIDI, SAIFI, and CAIDI statistics in inconsistent ways; for example, some utilities include data associated with "major events" in their public reporting to public utilities commissions, while others do not.[6] Utilities also take inconsistent approaches to defining "major events."[7] The lack of uniform national data inhibits more sophisticated analysis of macro trends in distribution reliability—something that is important to remedy in an electricity sector that is increasingly data intensive.

Also, although the predecessor to today's NERC was first formed in 1968 to address system reliability, the Institute of Electrical and Electronics Engineers (IEEE) Standard 1366 only formally defined industry reliability metrics in 1998.[8] The Energy Information Administration (EIA) began collecting distribution-level reliability data, including SAIDI and SAIFI information, in 2013—marking increased attention and effort on the reliability front. Yet, even today, only 33 percent of utilities report these statistics, covering 91 percent of the electricity sales in the Nation, which indicates that there is room for improving reliability reporting practices.[9]

There are other reliability measures and associated government reporting requirements as well. NERC, for example, collects the additional data it needs to promulgate reliability and security standards, but it does not make all of these data available to government agencies. Beyond reliability, a number of resilience metrics and measures have been proposed; however, there has not been a coordinated industry or government initiative to develop consensus or implement standardized resilience metrics, though the Grid Modernization Laboratory Consortium is launching the Foundational Metrics Analysis project to develop some resilience metrics.[10]

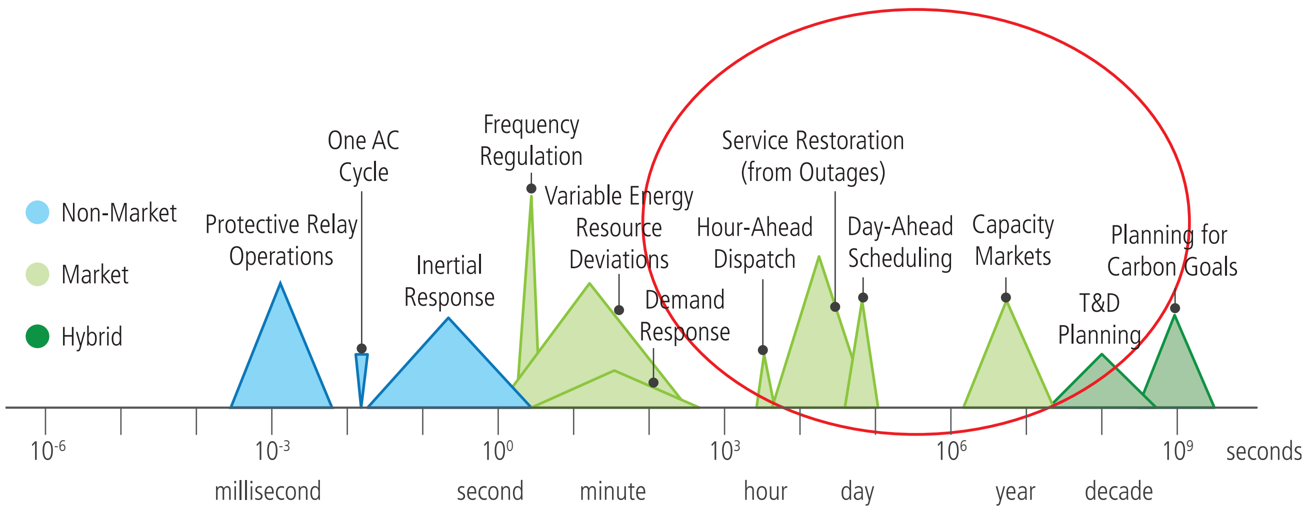
Time Scales and Grid Reliability

Throughout the 20th century, the design of power systems and early metrics (such as the loss of load expectation) focused on periods of maximum consumer electricity use. With more controllable loads, more variable generation, new technologies (such as storage), and the increasing importance of power system reliability, reliability is becoming a more complex concept, and reliability metrics and criteria must evolve accordingly.

Adequacy of generation resources is measured by a utility's reserve margin and has traditionally meant the extent to which utilities have adequate infrastructure to generate electricity to meet customers' needs. Generation reliability criteria is focused on installed generation to meet customer demand; the role of the customer as a system resource was not a consideration.

For vertically integrated systems, grid operators manage the entire electricity supply chain from end (generation) to end (delivery service). When new market structures were created across many U.S. regions in the form of independent system operators (ISOs) or regional transmission organizations (RTOs), end-to-end management was replaced with competing power generators. In these markets, variable generation may be the lowest cost generation; and, generation from certain power stations may not be accepted to run because they are not cost competitive for a specific day's operations. However, if a generator is deemed critical to system integrity, power stations can get "reliability must run" payments. These out-of-market payments, in turn, lower power market prices, which has been especially problematic for certain types of generation such as nuclear, which already faces challenges from low power prices due to the relatively low capital, operations, and fuel costs of natural gas–fired generators.

Figure 4-2. System Reliability Depends on Managing Multiple Event Speeds[11]



Markets are used for traditional grid operations, including hour-ahead, day-ahead, and capacity markets. Long-term planning reaches beyond typical market and financial signals. Acronyms: transmission and distribution (T&D), alternating current (AC).

Supply variability[b] is an important part of system operations, where ISOs/RTOs must ensure that risks of unexpected loss or variability of supplies are hedged by having some power plants immediately available (spinning reserves) and other plants able to supply power with short-term notifications of need (non-spinning reserves).

These adjustments to power flow management occur within the general framework of grid operations. This framework has historically been well understood by grid operators because the time dimensions of operations have not changed significantly, even when ISOs/RTOs were given responsibility for transmission system management. These dimensions, which operators have historically understood well, are seen in Figure 4-2 on the right side of the continuum, where the time scales of capacity markets, day-ahead, and hour-ahead products are depicted. For out-years beyond capacity contracts, traditional transmission and distribution system planning methods work to map and price investment requirements to ensure long-term grid reliability. Planning for decarbonization and climate resilience reaches beyond typical planning horizons for grid operators.

Changing Time Dimensions, Grid Topology, and Emerging Grid Management Challenges

Variable energy resources (VER) provide a range of benefits to utilities and their customers, including avoided fuel costs, greenhouse gas emissions, and costs associated with environmental compliance.[12, 13] In some cases, distributed VER are also credited with providing electric reliability and resilience benefits, particularly in the context of microgrids.[14]

However, the widespread integration of VER at both utility scale and distributed across all consumer segments significantly expands the time dimensions in which grid operators must function, and it complicates operations. It underscores the need "to coordinate time and space within the electric grid at greater resolution or with a higher degree of refinement than in the past."[15] A recent White House report noted, "The distinctive characteristics of [VER] will likely require a reimagining of electricity grid management."[16]

Impacts on transmission and distribution systems and integration options vary by scale. For instance, utility-scale solar power flowing onto high-voltage transmission lines can be smoothed and firmed up at the point of production by using smart inverters and storage. When onshore wind plants are integrated at a

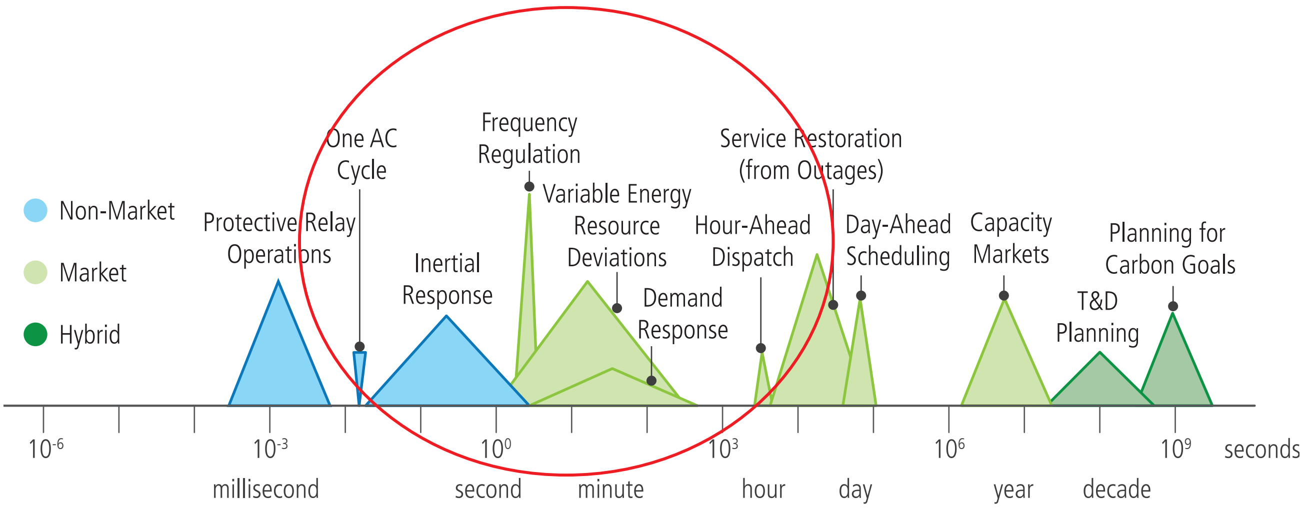
[b] As used here, variability refers to the difference between the expected and actual load or generation.

large geographic scale, lower correlation factors can smooth out variability. Assuming these aggregations are visible to grid operators to adequately assess both their costs and benefits, many aggregated distributed solar installations can smooth out the random variations from individual installations.

The time dimensions in which grid operators must function to accommodate the unique characteristics of VER and distributed energy resources (DER) are identified in the hourly, to minute, to second intervals (Figure 4-3). While grid operations are successfully managed today in some markets with relatively high levels of VER penetration,[17] this can complicate grid management. Consider a generic example of utility-scale generation portfolio management in a high VER supply system. Power supplied from solar stations has two types of variability to manage: minute-to-minute fluctuations and the dramatic drop in power supplied from solar as the sun goes down. This drop can be precipitous and occur within an hour or less.

Figure 4-3. System Reliability Depends on Managing Multiple Event Speeds[18]

Markets are used for grid operations in the order of seconds to minutes, such as frequency regulation and demand response (DR). Some essential



reliability capabilities, such as inertial response, occur faster than typical market signals. Acronyms: transmission and distribution (T&D), alternating current (AC).

Grid dispatch (actions that operators take to engage power suppliers to provide power to the grid) occurs around load changes, traditionally referred to as load-following activities. In grids with ISO/RTO wholesale markets, economic dispatch occurs based on which generators win daily auctions and produce power for the grid. ISOs/RTOs also load follow for grid management, and in regions with high VER production, load following and load shaping may provide linked challenges.

By calling or not calling on generators to produce electricity, grid dispatch determines the value that power producers obtain from their assets. Grid dispatch ensures system reliability through management of operating generators, as well as those waiting to be called if needed. In a world of subsecond decision making, dispatch effectiveness will require the integration of automated grid management, with continuing human oversight. The pace of change may dictate faster adaptation times for grid operators, but grid reliability may dictate a more methodical consideration of operating protocol changes, which are driven by changes in the types, scale, scope, and location of power supplies. Continuous engagement of grid dispatchers in planning for the 21st-century grid is essential.

VER fluctuations on the bulk power side of the equation can be mitigated by regulating power flows onto the grid—both up and down and from minute to minute. Mitigating power flows can occur with resources and services such as regulation that respond in one to several seconds; through process-flow techniques involving ramping up and throttling down generation plants; via transmission system blending with flexible resources such as hydro; and through demand response (DR) (including advanced water infrastructure),[19] which can be used to align demand with supply variations for grid services, including frequency regulation.

Variability is managed through geographic diversity and aggregation. FERC (through NERC) requires balancing authorities to constantly match supply and demand within their respective balancing areas.[c, 20] Larger balancing areas could help manage variability by sharing generation resources to smooth out supply. A recent National Renewable Energy Laboratory analysis concluded that, "consolidated operations of two or more balancing authorities fully captures the benefits of geographic diversity and provides more accurate response."[21] For example, the integration of PacifiCorp into the California ISO Energy Imbalance Market reduced the amount of required flexibility reserves by about 280 megawatts (MW), or 36 percent.[22]

While there is ramping associated with all generation technologies, because of their variability, baseload generators must ramp more frequently to accommodate VER. Ramping to match supply and demand can reduce the efficiency of baseload generators, possibly decrease their ability to recover capital costs, and increase fossil unit emission rates. Innovation to improve baseload generators' ramping capability is an important need that will become more important at high levels of VER. Recent analysis suggests that "…High renewable energy penetrations could significantly change dispatch requirements and use of conventional generators."[23] Also, price suppression is occurring in RTO/ISO wholesale markets, with noticeable amounts of wind and solar generation (and low-cost gas generation). While passing on savings to consumers is desirable, in some regions, these low prices have put pressure on baseload units, particularly zero-carbon emissions nuclear generation.

Better forecasting has also reduced VER integration costs. Most North American power markets dispatch wind plants along with conventional power plants based on current grid conditions and economics.[24] Setting wind generator schedules as close as possible to the dispatch time minimizes forecast errors, and using wind forecasting can greatly facilitate wind integration and reduce costs from carrying reserve capacity.[25]

Another complication, as noted earlier, is that system operators dispatch the least-cost mix of generation needed to meet load; these least-cost sources are often VER sources, which are fueled by the sun or the wind and therefore have low or zero marginal cost of production. In New England, as additional variable resources have come online, there has been "more frequent localized [transmission] congestion."[26] In the past, congestion was reduced by the system operator "through manual curtailment instructions that [were] not reflected in Real-Time Prices," causing a "mismatch" of signals, when generators who would normally respond to high prices by increasing output were instead told to decrease output in order to maintain reliability.[27] The system operator has undertaken several steps to address these challenges, and in April 2016, wind and hydro resources were designated as automated dispatch.[28] Going forward, the system operator will require a series of actions to further integrate VER sources.[29] Specifically, on October 12, 2016, ISO New England filed proposed revisions to its Transmission, Markets, and Services Tariff with FERC, which in part were made to "more directly incorporate non-dispatchable, intermittent power resources into [market pricing]", and on December 12, 2016, FERC issued an order accepting the proposal.[30, 31]

Another example of the changes to grid management made in response to increasing penetrations of VER is seen in the California market. Under existing operations, the California ISO found that "the fleet of resources committed…to provide energy often does not provide sufficient flexible ramping capability…to meet the

[c] A balancing authority "integrates resource plans ahead of time, maintains demand and resource balance within a Balancing Authority Area, and supports interconnection frequency in real time." The Balancing Authority Area (shortened here to Balancing Area) is the "collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority." From North American Electric Reliability Corporation (NERC), "Glossary of Terms Used in NERC Reliability Standards," NERC, last modified November 28, 2016, http://www.nerc.com/files/glossary_of_terms.pdf.

actual changes in net load."[32] As a result, the operator must "dispatch units out of economic sequence, or dispatch units that are not in the market," imposing "additional costs on the system" and creating "prices [that] do not reflect such marginal costs."[33] In California, the ISO addressed this issue by amending its tariff to "enhance the CAISO [California ISO] ability to manage the ramping capacity necessary to meet changes in net load—both forecasted and unexpected."[34]

Real-time wind penetration in the Southwest Power Pool (SPP) has, at times, approached 40 percent of generation.[35] Between March 2016 and May 2016, wind accounted for 21.5 percent of all energy generated in SPP.[36] In examining scenarios with significantly more VER, SPP found that new procedures "would enable the SPP transmission system to reliably handle up to…60% wind penetration"[37] while lowering overall costs and reducing price volatility.[38] These new procedures include increasing the dispatchability of renewable resources, adding additional transmission capacity, enhancing ancillary services, and adding new tools to manage inter-hour ramps.[39]

In the Pacific Northwest, an increase in wind generation has meant that the operator must "dispatch units out of economic sequence, or dispatch units that are not in the market," imposing "additional costs on the system" and creating "prices [that] do not reflect such marginal costs."[40] Additionally, an increase in wind generation has meant that "utilities must hold more resources in reserve to help balance demand minute-to-minute," increasing "the need for system flexibility."[41] The Northwest Power and Conservation Council anticipates, however, "that the region will have sufficient generation and demand side capability on its existing system to meet balancing and flexibility reserve requirements over the next six years if [the region's] energy efficiency and demand response development goals are achieved."[42]

Hydropower provides a variety of essential reliability services that are beneficial to the electricity system. One example is regulation and frequency response (including inertia), in which hydropower generators can quickly respond to sudden changes in system frequency, making hydro a very suitable complement to wind generation. Other essential reliability services include spinning and supplemental reserves enabled by high ramping capability, reactive power and voltage support, and black start capability.

Despite hydropower's technical ability to provide essential reliability services, these services are not always explicitly compensated by existing market structures. For example, hydropower is one of the main providers of inertia and primary frequency response in the Western Electricity Coordinating Council, but it is not explicitly compensated for either service.[43] Some recent market advances have been made that allow greater ancillary service participation. For example, FERC now requires ISOs to better compensate generators for frequency regulation services based on their response speed and flexibility to respond to a range of situations.[44] In addition, in June 2016, FERC issued Order No. 825, requiring all RTOs and ISOs to implement subhourly settlements, allowing more accurate alignment of the services provided with the prices paid for them. Market rules governing participation of flexible resources, such as hydropower and pumped storage, could be reviewed to determine if additional changes could allow these resources to participate more effectively and ensure just and reasonable compensation.

Part of the challenge facing hydropower lies in the difficulty of optimizing the limited generating ability of hydro resources due to non-market environmental and competing use constraints. Determining the best use of hydro resources through manual dispatch or market-based bidding process can be difficult because the value of essential reliability services can change quickly due to a number of factors, including location, day, time, regulatory constraints, and interaction with other generators. Moreover, in the long term, the best use of hydro resources may evolve as the generation mix changes.[45] Essential reliability services are, however, undervalued in some existing market structures.

On the consumer side of the utility meter, consistent growth in DER (of which distributed VER are a subset) has also changed how grid operators sustain high system reliability at both the distribution and transmission levels of electricity delivery. DER represent a broad range of technologies that can significantly impact how much, and when, electricity is demanded from the grid, and they include distributed generation (DG) and storage technologies, as well as DR.[46] Consumers with rooftop solar may influence their demand frequently and in diverse ways. This can impact total load (tending to reduce it) but may not be directly controlled by grid operators. Other DER, such as truly dispatchable DR, can be directly managed and called by grid operators when needed.

Deployment of distributed VER places additional design and operational requirements on distribution grid operators. Currently, distribution systems are predominantly radial networks (feeders) delivering grid-supplied power to customer premises. With significant penetration of distributed generation, some distribution utilities are facing new demands to interconnect multiple feeders together to accept customer-generated power and to be able to balance generation and demand. The new structure and roles of distribution systems will require development of advanced distribution circuits and substations to enable significant two-way power flows, new protection schemes,[d] and new control paradigms.

Grid Frequency Support from Distributed Inverter-Based Resources in Hawaii

Hawaii leads the United States in the portion of its electricity that is produced from variable renewable sources, and as an island state, it cannot rely on neighbors to help balance generation and load. Hence, the Hawaiian Electric Companies are currently experiencing the bulk system frequency stability impacts that mainland U.S. power systems will experience in the coming years and decades.[e] The Grid Modernization Laboratory Consortium will develop, simulate, validate, and deploy practical solutions that enable distributed energy resources (DER) to help mitigate bulk system frequency contingency events on the fastest time scale (milliseconds to seconds).[f] The project will examine the ability to leverage the fast response capability of power electronics to enable photovoltaic inverters and storage inverters to support grid frequency starting a few fractions of a second after the appearance of a frequency event. The capabilities of currently available products to provide rapid frequency response will be characterized, and new capabilities will be developed with a goal of maximizing DER's ability to support grid frequency stability.

[e] William Parks, Kevin Lynn, Carl Imhoff, Bryan Hannegan, Charles Goldman, Jeffery Dagle, John Grosh, et al., *Grid Modernization Multi-Year Program Plan* (Washington, DC: Department of Energy, November 2015), 2, https://energy.gov/sites/prod/files/2016/01/f28/Grid%20Modernization%20Multi-Year%20Program%20Plan.pdf.

[f] "Pioneer Regional Partnerships," Grid Modernization Laboratory Consortium, https://gridmod.labworks.org/pioneer-regional-partnerships.

California's recent experience with its requirements for 20,000 MW of small renewable generation (under 20 MW) by 2020 is instructive for both valuation and grid management. To make these volumes both visible to the ISO and valuable to consumers, aggregators, and grid operators, market designers at the California ISO allowed bids of at least 0.5 MW into day-ahead, energy, and ancillary markets. Similar efforts are underway in Texas and New York.[47]

The electricity system is also experiencing an increasing array of "subsecond" events that require response times that are far too short for humans to react. One of the driving forces making smart grids necessary is the proliferation of smart devices; each one is capable of microscopic frequency disruptions, which cumulatively

[d] Protection schemes identify coordinated corrective actions to detect and address abnormal system conditions (e.g., faults).

present an unprecedented new challenge for system operators. Many consumer electronic devices (such as mobile phones, Wi-Fi-based home automation solutions, and smart entertainment devices) represent "endpoints" that can impact system operations. In addition, Internet of things (IoT) devices function at microsecond "clock speeds." In the aggregate, these devices represent a new source of variability at speeds far faster than what grids have traditionally managed. The solution must take the form of protective relays and synchrophasors operating more-or-less autonomously in real time. The upside implications going forward include the need for integrating machine learning into grid operations (i.e., as positive solutions for mitigating unprecedented grid disruptive forces); on the downside, digitizing grid operations deep into subsecond operations raises new cyber vulnerabilities.

The kinds of anomalies affecting wholesale markets and grid operators noted above suggest the need for frequent adjustments to market designs to accommodate new technologies, changing consumer preferences, and security needs. The Nation's ISOs/RTOs, FERC, and NERC are continuously engaged in analysis, evaluation, and design modification processes—working to ensure that the present scoping and pace of regulatory change is aligned with the scale and speed of change occurring as a result of continued VER deployment. In September 2016, FERC approved new requirements for the quality of real-time monitoring and analysis capabilities for system operators,[48] and NERC has made a number of improvements that have significantly reduced the time it takes to develop a standard. This is an ongoing process; both state and Federal regulators face complicated and evolving challenges that grid operators must address in a timely fashion while simultaneously operating under existing performance standards and system requirements.

Grid Operation Impacts of the Internet of Things

Grid control systems now handle, sense, and control endpoints numbered in the thousands. Widespread DER/DR penetration implies that future grid control systems may have to coordinate millions of endpoint control devices to support grid functions. These devices vary in type, from digital sensors and smart boards built into transformers, to mobile devices used by field operators and grid control managers.

Current grid control systems are not structured for large-scale optimization of millions of devices, and they are not equipped to handle increasingly large volumes and types of data. End-users (consumers, as well as aggregators controlling multiple demand profiles) may wish to perform optimal local controls to meet their desired requirements that may be in conflict with optimal *system-wide* control.

Grid control systems must evolve from being centralized to a hybrid of central and distributed control platforms. The need for flexible grid operations is challenging basic assumptions about grid control, which will require changes in standards and operating protocols. Bulk power systems operations are the purview of both FERC and NERC, but grid security and reliability assurance concerns mean that Federal authorities must be included in designing 21st-century grid control systems.

Overview of Department of Homeland Security Strategic Principles for Security of the Internet of Things (IoT)

The Department of Homeland Security developed strategic principles, published on November 15, 2016,[g] to mitigate vulnerabilities introduced by the IoT through recognized security best practices. These principles are intended to offer guidance to stakeholders as they seek to manage IoT security challenges.

Strategic Principles for Securing the IoT:

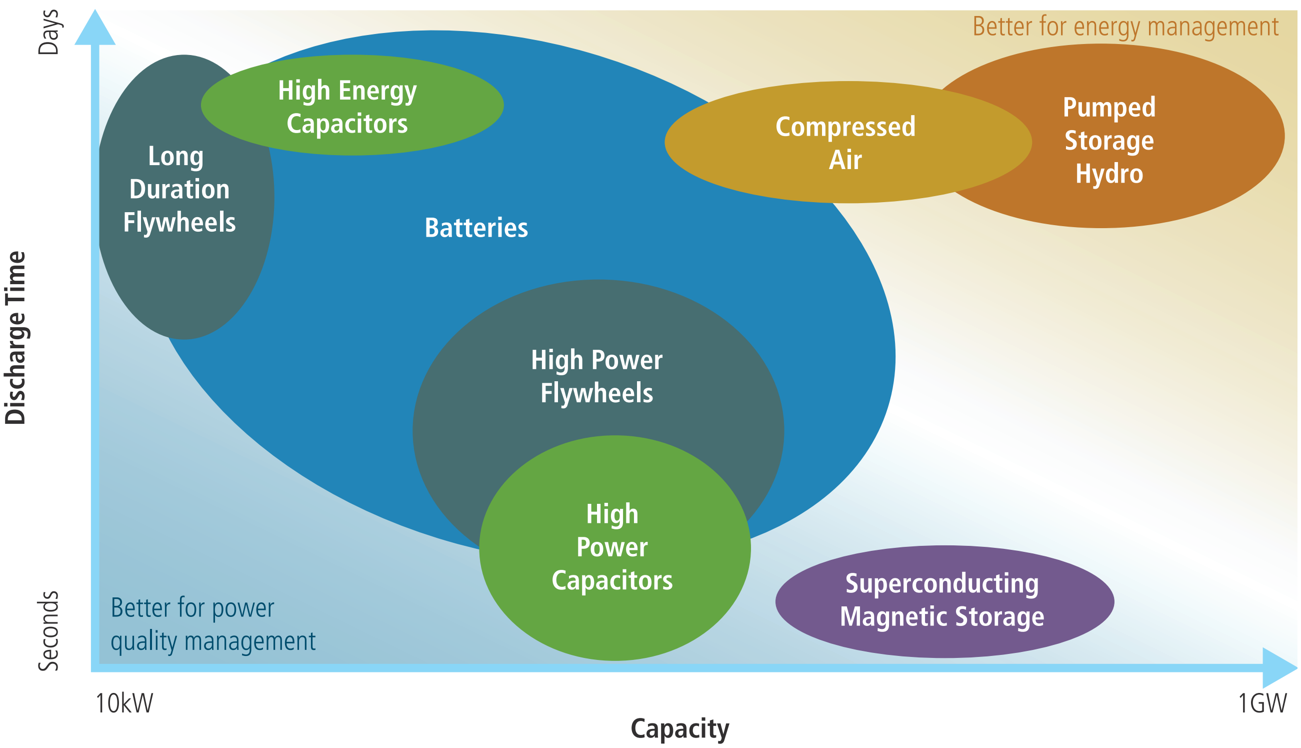
1. Incorporate security at the design phase—building in security at the design phase reduces potential disruptions and avoids the much more difficult and expensive endeavor of attempting to add security to products after they have been developed and deployed.
2. Advance security updates and vulnerability management—vulnerabilities may be discovered in products after they have been deployed. These flaws can be mitigated through patching, security updates, and vulnerability management strategies.
3. Build on proven security practices—many tested practices used in traditional information technology and network security can be applied to the IoT, helping to identify vulnerabilities, detect irregularities, respond to potential incidents, and recover from damage or disruption to IoT devices.
4. Prioritize security measures according to potential impact—risk models differ substantially across the IoT ecosystem, and the consequences of a security failure across different customers will also vary significantly. Focusing on the potential consequences of disruption, breach, or malicious activity across the consumer spectrum is therefore critical in determining where particular security efforts should be directed and who is best able to mitigate significant consequences.
5. Promote transparency across the IoT—increased awareness could help manufacturers and industrial consumers identify where and how to apply security measures, build in redundancies, and be better equipped to appropriately mitigate threats and vulnerabilities as expeditiously as possible.
6. Connect carefully and deliberately—IoT consumers can also help contain the potential threats posed by network connectivity, connecting carefully and deliberately, and by weighing the risks of a potential breach or failure of an IoT device against the costs of limiting connectivity to the Internet.

[g] Department of Homeland Security (DHS), *Strategic Principles for Securing the Internet of Things (IoT) Version 1.0* (Washington, DC: DHS, November 15, 2016), https://www.dhs.gov/sites/default/files/publications/Strategic_Principles_for_Securing_the_Internet_of_Things-2016-1115-FINAL....pdf.

Utility-Scale and Distributed Storage

Electricity remains unique among commodities in its limited capability available for storage. There are few viable ways to store electrical energy (e.g., batteries, or pumped storage solutions), and there are other more exotic possibilities like superconducting magnet rings. Inventory options tend to narrow the amount and duration of ready access electricity. The graphic depiction in Figure 4-4 summarizes the power and duration capabilities of various storage technologies.

Figure 4-4. The Storage Technology Development Map[49]



Most electricity storage is water that fuels turbines that produce electricity. Currently, the largest storage capacity is pumped hydro. Electrochemical batteries have been the fastest growing new storage technology. Batteries in the form of fuel cells can be used for continuous power production and the scaling capabilities of fuel cells make them attractive for fitting load shapes to specifically sized power supplies. Other technologies for energy storage include compressed air, flywheels, and capacitors.

Utility-scale battery storage and distributed battery storage vary by scale and duration, but perform consistently at any scale from a grid management perspective. When distributed storage is aggregated, it can offer local grid operators greater flexibility for managing system reliability and power quality than utility-scale resources. Aggregation can be scaled to fit specific local needs in distribution systems.

An example of grid reliability applications of energy storage is seen in California, where the building of about 60 MW in new battery storage capacity is underway.[h, 50, 51, 52] These installations are being built to resolve reliability issues caused by the Aliso Canyon leak[53] (for more information on Aliso Canyon, see "Underground Storage Leak in California Driving Natural Gas Storage Safety and Reliability Improvements" text box on page 4-33) and the San Onofre Nuclear Generating Station outage,[54] and they will help level out electricity supply in California by moving energy from the afternoon production of solar to the evening peak.[55] While region-specific critical reliability requirements can drive storage deployment, additional incentives can help accelerate these benefits ahead of a major disruption.

[h] Upon commissioning, the 20-MW/80-megawatt-hour (MWh) SCE Mira Loma project will be the largest battery in operation. The 37.5-MW/120-MWh San Diego Gas & Electric Escondido project will then overtake Mira Loma as the largest battery when it is commissioned. In addition to their titles as largest yet in operation, both projects were built quickly—about six months from contract award to commissioning. These projects show how new technologies, many of which benefitted from early publicly supported demonstrations, can provide rapid solutions for reliability, resilience, and security.

Public investment and policy have been key to electricity storage technology development; the American Recovery and Reinvestment Act of 2009 (ARRA) is the most commonly identified funding source for storage projects.[56] By 2015, through a combination of regulatory reforms, innovation, and cost reductions, lithium-ion batteries emerged as a dominant battery design for frequency regulation and renewables integration; lithium-ion batteries made up 95 percent of deployed capacity in 2015, with 80 percent of this capacity located in the PJM Interconnection territory, attracted by its pay-for-performance frequency regulation market.

The evolution of storage technology is likely to take the electricity sector into new realms. "Hybridizing" storage solutions with solar and wind power sources may redefine what is meant by "power plant," and alter how the grid is understood and used. If hybrids can "self-power" even a portion of a significant load, then tomorrow's future electricity sector will be able to achieve national objectives for clean, secure, and affordable electricity supplies in a system that is imminently flexible and considerably resilient.

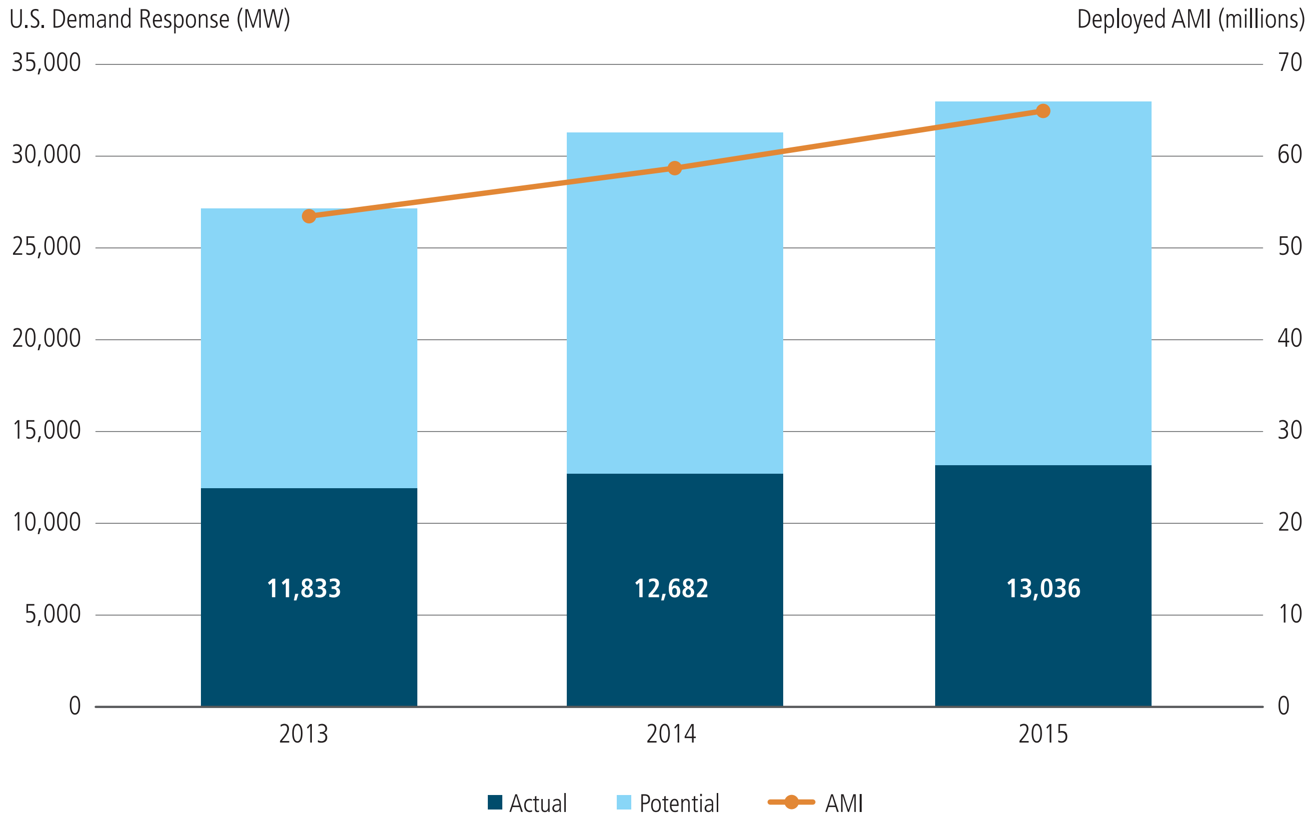
Demand Response Can Aid Grid Management

DR empowers consumers to change their normal electricity consumption patterns; it is a particularly flexible grid resource, capable of improving system reliability, reducing the need for capital investments to meet peak demand, as well as electricity market prices. DR can also be used for load reduction and load shaping, as well as to help grids mitigate generation variability, including from VER. A variety of DR programs exist, some of which are offered directly by utilities, while other programs are offered by the grid system operators, retail competitors, and aggregators. DR challenges the view that a utility's generation adequacy, measured by its reserve margin, is "steel in the ground." DR can offset "installed capacity" and currently provides nearly 30 gigawatts (GW) of peak reduction capability nationwide;[57] this accounted for 3.9 percent of U.S. peak demand in 2016[58] and exceeded 10 percent in some regions.[i, 59, 60] Future DR growth—FERC scenarios show 82 GW to 188 GW in possible DR capacity by 2019[61]—along with other DER could significantly shift customer demand from peak to off-peak periods.

A key driver of today's DR programs has been the growth of advanced metering infrastructure (AMI), now deployed for nearly 65 million customers in the United States (Figure 4-5).[62] AMI typically includes two-way communications networks that utilities can leverage to improve electric system operations, enable new technological platforms and devices, and facilitate consumer engagement. More than half of deployed AMI are in five states, with California, Florida, and Texas accounting for over 40 percent of the total.[63] AMI investments have been largely driven by state legislative and regulatory requirements, as well as ARRA funding.[64]

[i] For example, in PJM Interconnection, demand resources account for over 10 GW out of the 167 GW from all capacity resources in the 2019/2020 delivery year. See references for more information.

Figure 4-5. Advanced Metering Infrastructure Growth Has Contributed to Expanded Role of DR Programs[65]



A key driver of today's DR programs has been the growth of advanced metering infrastructure (in orange). In 2015, approximately 65 million customers in the United States had advanced metering infrastructure installations.

State Regulatory Actions That Have Impacted Demand Response[j]

- The California Public Utilities Commission will require default time-of-use (TOU) rates for residential customers in 2019, and it is working with California Independent System Operator and the California Energy Commission to create a market for demand response (DR) and energy efficiency resources.[k]
- In 2014, Massachusetts ordered its electricity distribution companies to file TOU rates with critical peak pricing as the default rate design for residential customers once utility grid modernization investments are in place.[l]
- In 2015, the Michigan Public Service Commission directed DTE Electric to make TOU and dynamic peak pricing available on an opt-in basis to all customers with advanced metering infrastructure by January 1, 2016. Similarly, Consumers Energy must make TOU available on an opt-in basis by January 1, 2017.

[j] Federal Energy Regulatory Commission (FERC), *Assessment of Demand Response & Advanced Metering, Staff Report* (FERC, December 2015), https://www.ferc.gov/legal/staff-reports/2015/demand-response.pdf.

[k] California Public Service Commission (CPUC), *California's Distributed Energy Resources Action Plan: Aligning Vision and Action, Discussion Draft: September 29, 2016* (CPUC, 2016), http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/About_Us/Organization/Commissioners/Michael_J._Picker/2016-09-26%20DER%20Action%20Plan%20FINAL3.pdf, accessed December 13, 2016.

[l] L. Evers, "Massachusetts DPU Says Time of Use Pricing Will Be the Default for All Customers," Smart Grid Legal News, June 26, 2014, http://www.smartgridlegalnews.com/regulatory-concerns-1/massachusetts-dpu-says-time-of-use-pricing-will-be-the-default-for-all-customers/.

State Regulatory Actions That Have Impacted Demand Response (continued)

- Also in 2015, the New York Public Service Commission released a regulatory framework and implementation plan ("Reforming the Energy Vision") to align electric utility practices and the state's regulatory framework with technologies in information management, power generation, and distribution. A related measure in 2014 approved a $200 million Brooklyn-Queens demand management program, which includes 41 megawatts (MW) of customer-side measures, including DR, distributed generation, distributed energy storage, and energy efficiency, to cost effectively defer approximately $1 billion in transmission and distribution investment.
- In June 2015, the Pennsylvania Public Utility Commission set a total peak demand reduction of 425 MW for electric distribution companies by 2021, against a 2010 baseline.
- In Rhode Island, DR is continuing to be tested in pilot programs by National Grid and will be incorporated in analysis for "non-wires alternatives" to traditional utility infrastructure planning.[m]

[m] "System Reliability Program," State of Rhode Island, Office of Energy Resources, accessed December 13, 2016, http://www.energy.ri.gov/reliability/.

The legal and regulatory environment for DR is highly dynamic and evolving at both the national and state levels. On January 25, 2016, the U.S. Supreme Court upheld FERC's authority to regulate DR programs in wholesale electricity markets (FERC Order No. 745).[66] While this decision provides final policy clarity, it was made almost 2 years after the Appeals Court issued the opposite decision; in the intervening time, the markets were operating under the lower court's interpretation that FERC's DR order was encroaching on each state's exclusive right to regulate its utility markets. As affirmed by the Supreme Court, the FERC order ensures that DR providers are compensated at the same rates as generation owners. This ruling is also expected to provide a more favorable environment for DR market growth by facilitating the participation of third parties in the aggregation of DR resources.

Total DR capacity varies widely by region, reflecting the diversity in utility, state, and regional policies toward DR and other forms of demand-side management. Regions where DR is installed directly in multiple electricity markets (e.g., capacity and essential reliability services) generally have greater total DR capacities and can reduce a larger proportion of their peak demand by using DR.[67]

It is important to note that the potential peak reduction in Table 4-1 may not all be reduction in "real capacity." There are significant challenges to making DR resources reliable, predictable, and sustainable so that they may function as "proxy generators." Also, the terms related to non-delivery or partial delivery of DR that is called into service by grid operators tend to have highly variable penalty clauses from region to region, and from utility to utility, grid operators generally favor more reliable and predictable resources over DR. Until there are consistent standards across regions that ensure data accuracy and validity, data on DR capacity will tend to be discounted by grid operators—an estimated 100-MW DR resource that *can* be called does not mean that 100 MW will show up *when* called. Real-time visibility of these resources is important to grid operators and essential for maximizing the value of DR.[68]

Table 4-1. Potential Peak Reduction from Retail DR Programs, by Region and Customer Class[69]

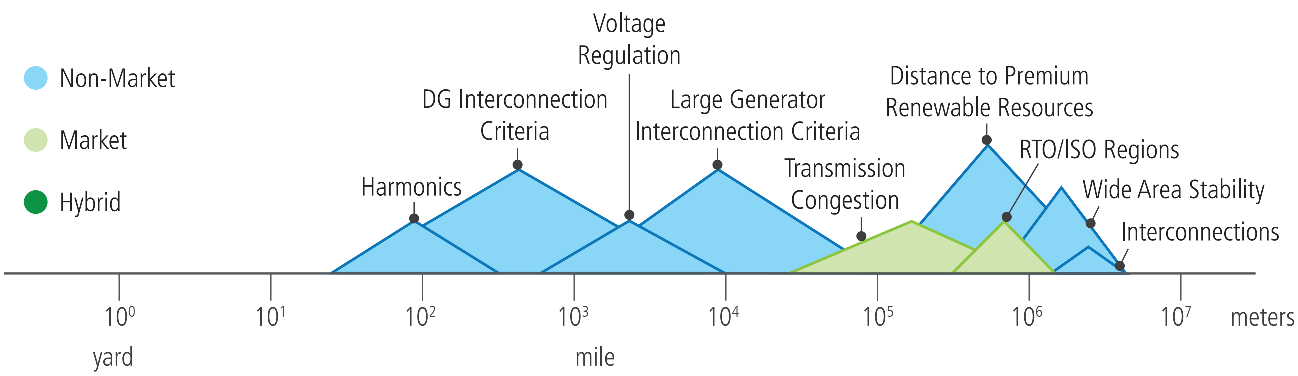
NERC Region	Total DR Capacity (megawatts)	Residential	Commercial	Industrial	Transportation
Alaska	27	19%	48%	33%	0%
Florida Reliability Coordinating Council	1,924	42%	39%	19%	0%
Hawaii	35	57%	43%	0%	0%
Midwest Reliability Organization	4,264	44%	19%	37%	0%
Northeast Power Coordinating Council	467	8%	55%	34%	3%
ReliabilityFirst Corporation	5,362	29%	13%	58%	0%
SERC Reliability Corporation	8,254	16%	10%	74%	0%
Southwest Power Pool	1,594	13%	20%	66%	0%
Texas Reliability Entity	459	19%	74%	7%	0%
Western Electricity Coordinating Council	4,681	22%	24%	50%	3%
Unspecified	28	100%	0%	0%	0%
Totals	27,095	25.8%	18.9%	54.6%	0.6%

DR resources tend to be drawn principally from industrial and commercial customers of utilities, although three regions—Florida Reliability Coordinating Council, Hawaii, and Midwest Reliability Organization—exhibit high-residential DR capacity. Variability among segments within and between regions is a function of DR program characteristics and requirements: whether penalties for non- or under-performance apply, the frequency with which DR resources are called, and the purpose for which DR is used, such as peak mitigation or frequency regulation. Capacity estimates must be adjusted for value and reliability of delivery based on operational outcomes, as well. DR, when called, may not sustain for a complete event period; only a portion of what is called may show up; resource availability may vary over an event period; and sometimes the "snap back" at the end of an event can create "echo effects" of peak mitigation problems, as well.

Topography and Geography are also Important to Grid Operators

Topography and geography are additional and important aspects of core grid management challenges (Figure 4-6). Geography is the physical area covered by the grid; topography is the type of geography (e.g., flat, hilly, mountainous, etc.). Figure 4-6 illustrates how physical distances can influence system structure and operational challenges.

Figure 4-6. Network Geography and Topography Impact Real-Time Operations Management and Influence How System Planning Is Done for Grid Operations and Related Markets.[70]



A variety of grid services are managed across different distance scales and markets, and they can be used to integrate some necessary services.

An example of why these features are important is that information and communications technology (ICT) infrastructure and reliability for smart meters and smart grid assets are less effective when mountainous terrain and urban infrastructure disrupt reliable wireless signal strength. Smart grid designers must and do build in redundancy to deal with certain topographic asymmetries by using multiple ICT channels.

As another example, the concentration of distributed VER in a specific urban geography can lead to stresses on local infrastructure, including transformers and substations. This can present more disruptive problems for local grid operators than non-clustered dispersion of VER. System operators must watch for grid impacts in more granular ways, and grid design changes to mitigate clustering effects will become important new paths for adapting to consumer-side influences on grid operations. Because consumer behavior can change quickly, new grid design processes must be made to function faster, from core architecture to actual deployment. In turn, regulators must become nimble in considering incremental system costs that are compelled by grid operators anticipating problems and acting to mitigate them before they lead to grid interruptions.

The Growing Role of the Consumer in Grid Reliability

Reliability is increasingly a two-way proposition between grid operators and consumers, and grid reliability, while remaining true to its longstanding commitment to ensure high system "uptime," now abuts an emerging "consumer reliability." Reliability has typically been synonymous with "grid reliability" or "system reliability." Consumer reliability derives from a series of initiatives over several decades; the continuous improvement in energy efficiency; the value of DR to both the grid and consumer; emerging new consumer value creation from the IoT development; and the shifting priority of consumers (especially the commercial segment) for uninterruptible power services. The growing interdependence between grid operators and consumers—the two-way flow of information and power—means that grid reliability can be made more efficient and more robust if consumer integration into grid operations occurs.

Customer Engagement in Demand-Side Management

Today, many customer categories and segments are interacting with the grid. Customers now have the tools to alter their consumption patterns in response to price signals or requests from grid operators. This significant change—from a customer that is a passive load to one that is more actively engaged in demand management—may trend toward greater customer participation in the future. Within 10 to 15 years, many of the new devices likely to become part of our electricity system—from power plants to rooftop solar systems, from batteries to street lights, from transformers to electric vehicles—will also be digitally communicating with the grid.[71, 72] Most of these new devices will be able to "see" others on the grid, as well.

This kind of connectivity with customers may lead to more fully integrated customer participation in grid operations on either an active level—where customers respond to time-of-use or real-time price signals—or a passive level—with devices encoded to reflect customer preferences that are responsive to system prices and operating signals. Visibility of this connectivity is, however, key to grid operations and management and essential for both customer and system reliability.

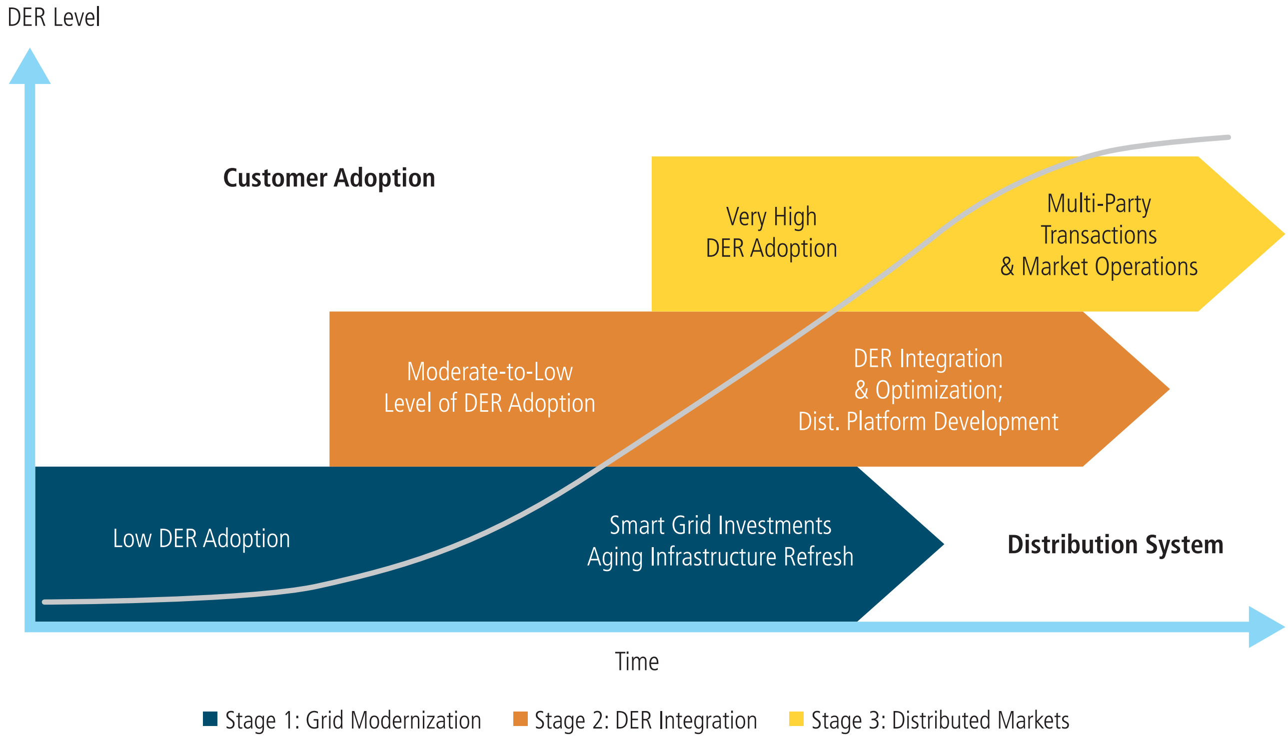
Consumption response to system signals can be more precise, timely, and predictable thanks to improved ICT enablers and better grid-side analytics focused on managing overall system reliability, not just peak mitigation. DOE, through its laboratories, for example, has developed a platform that "enables mobile and stationary software agents to perform information gathering, processing, and control actions and independently manage a wide range of applications, such as HVAC [heating, ventilation, and air conditioning] systems, electric vehicles, distributed energy or entire building loads, leading to improved operational efficiency." This platform provides the capabilities for real-time, scalable distributed control and diagnostics that we need for security and reliability and "…the integration of today's new energy system."[73]

Customer Engagement in Generation and System Reliability

In addition to the potential for increased customer participation in demand side management, there have been dramatic increases in distributed generation, such as rooftop solar, which enable customers to produce power that is sold back to the grid by the customer or aggregators acting on behalf of the customer. The result is that both electricity and information can now flow in two directions across the distribution grid, enabled by smart meters and/or Internet platforms. This two-way engagement has become more complex as distributed generation continues to penetrate industrial, commercial, and residential delivery service segments.

Most utilities are in the low distributed generation adoption phase, with some states approaching moderate levels.[74] Regulatory characteristics within each state will drive growth (e.g., through rate design and utility regulation as set by a public utilities commission). Figure 4-7 shows the conceptual growth of DG/DER in three phases, from low to high adoption. Such conceptual forecasts are helpful in posing policy issues and assisting investors in seeing new opportunities. However, structural and systems outcomes depend as much on actual results of markets, regulators, and various jurisdictions co-evolving into the future.

Figure 4-7. Major Technology, Policy, and Infrastructure Enablers of DER Adoption[75]



This figure shows a three-stage evolutionary framework based on an assumption that the distribution system will evolve in response to both top-down policy and bottom-up customer drivers. Each level includes additional functionality to support greater amounts of distributed generation/distributed energy resources (DG/DER) adoption and complexity building upon the earlier level. Most of the U.S. distribution system is at stage 1; the speed and nature of DG/DER adoption will vary by region based on top-down and bottom-up drivers.

Currently, around 4 percent of U.S. generation is from DG, although this varies widely by region.[76] Low levels of DG penetration generally require modest, though critical, levels of planning and operational considerations. Under high DG adoption rates, grid operations and market structures will most likely require significant modification. In a future grid where DG comprises a larger portion of the resource base, disruptions of system dispatch and control signals that could result from higher levels of DG penetration will increase the risk of disturbing grid stability and reliability. In its "2015 Long-Term Reliability Assessment," NERC noted the complications DG/DER create for grid operations and how these issues might be resolved:

> "Operators and planners face uncertainty with increased levels of distributed energy resources and new technologies. Distributed energy resources (DERs) are contributing to changing characteristics and control strategies in grid operations. DERs are not directly interconnected to the BPS [bulk power system], but to sub-transmission and distribution systems generally located behind customer metering facilities. Visibility, controllability, and new forecasting methods of these resources are of paramount importance to plan and operate the BPS—particularly because the majority of DER are intermittent in nature and outside the control of the System Operator. As more DER are integrated, the supply of control to System Operators can decrease. However, distribution-centric operations can reliably support the BPS with adequate planning, operating and forecasting analyses, coordination, and policies that are oriented to reliably interface with the BPS. Coordinated and reliable integration of DERs into the BPS can also present opportunities to create a more robust and resilient system."[77]

At high penetration levels, distribution system changes to enhance DG/DER value to grid reliability will require developing advanced distribution circuits and substations that allow for two-way power flows, new protection schemes, and new control paradigms. There are digital solid-state technologies combined with ICT, such as smart inverters, power electronics, and smart energy storage that can provide grid operators the flexibility needed to manage a mixed set of DER and deal with inbound impacts from utility-scale VER upstream as well. The introduction of new grid control and optimization algorithms taking advantage of distributed generation and load flexibility in the United States could also contribute to grid reliability and related benefits, such as reduction of renewables curtailment, peak load mitigation, and transmission and distribution (T&D) congestion management. Development of new technologies could enable DG to provide voltage or reactive[n] control resources.

Currently, customer reliability investments and interests are not necessarily contributing to supporting and enhancing overall grid system reliability. The electricity sector has a range of choices to adapt to these challenges and demands, many of them coming from new generators and consumers. The path that is chosen will shape future sector value-creation potential and the long-term relevance of utilities to electricity service delivery. Technology innovation, along with market forces, are redefining "grid reality," the management space where high system reliability is sustained under the aegis of critical national goals for a clean, secure, and competitive electricity sector.

Increased penetration of DGs and increased interconnectivity also bring increased vulnerabilities to malicious attacks on customer assets and on the grid. Public networks carry with them risks of being conduits through which cyber attacks can be executed—where impacts can spread through grids as well as through customer assets that are part of the IoT. There are policy gaps at the interface of electricity and information that require new policies that both promote value creation through connectivity and protect critical infrastructure against cyber attacks.

Valuation of DER: System Benefits and Costs

The growth of DER, where significant, will require additional valuation efforts in both planning and market design to capture the value of these new systems and services, as well as to avoid uneconomic or unintended issues. Valuation can be developed based on different cost perspectives, such as private costs that affect the ratepayers' cost of service or social costs that include the private cost of service and externalities. Valuation efforts need to be performed for a system as a whole, as well as for planning and compensation structures (e.g., rate design).

It is important to consider both the system cost and benefits when valuing DER. Factors that influence DER value include constraint reduction, loss reduction, voltage control, investment deferral, environmental benefits, and reliability. These factors can vary significantly based on the size and location of the DER. Accurate valuations will depend on evaluations at a finer level or resolution than has been considered historically.

Flexibility and Management of DER, VER, and Two-Way or Multi-Directional Flows

Resilience and flexibility might be considered complementary factors of grid modernization. Grid modernization planning should take flexibility of resources, as well as grid operations techniques, into account; architecting a flexible grid may require distinctive configurations of ICT and physical assets on the grid side, as well as the customer side, of the utility meter. Flexibility is not only a generation matter; it bears directly on the core reliability challenges of maintaining balance between generation and load.

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n NERC requires transmission operators to ensure that resources capable of providing "reactive power" or "voltage control" in addition to electricity are online or can be scheduled because these reactive power or voltage control services regulate voltage levels that maintain grid stability.

Solar and wind (which are not synchronously connected to the grid) contribute to a net decrease in system inertia (loss of frequency control). System frequency[o] must be managed tightly around 60 Hertz; it measures how well the supply and demand of electricity are in balance, which has significant implications for how resources are deployed literally minute-to-minute. Conventional generation, such as nuclear facilities or coal-fired power stations, serve as baseload resources and as spinning reserves. These resources are synchronously connected to the grid and provide system inertia.[p] Deviations in frequency are corrected by the spinning mass and governor controls of conventional generators, which automatically adjust electricity output within seconds to correct out-of-balance conditions.

In contrast, conventional solar photovoltaic (PV) generators, storage devices, and non-frequency responsive loads do not have inertial value for grid operators. As wind and solar power (and other non-synchronous DER) replace conventional synchronous generation, total system inertia is reduced along with the number of units available to provide frequency response services. In other words, system flexibility could be compromised in the absence of intentional mitigating actions that preserve or boost frequency response capabilities. Power electronics and advanced inverters that simulate inertia are available to add to wind and solar generators, providing a version of frequency response; but, development and deployment of these technologies may be hindered without additional policies prioritizing or enabling frequency response service.[q, 78]

Steep ramping resources will become more important as more VER come online and increase their share of power supply. Ramping is used to follow load patterns to ensure that resources match the loads on the system. VER expand the role of ramping from being primarily load focused to more of a role in matching increasing supply variability. For example, in California in 2015, grid operators were required to bring on approximately 10,000 MW within a 3-hour period at the end of each workday to compensate for the reduction in PV output as the sun was setting. Over time, more ramping will be needed as variable resources continue to grow.[79] There is not yet an established method for calculating the type of flexibility required to ensure reliability, especially in circumstances with high penetration of variable or DG.

Distribution systems were designed to deliver power to customers rather than receive power from them. When the same grid assets are tasked with handling power delivered to the grid, as well as power delivered to customers, the settings on many field devices (such as capacitors, feeder switches, and relays) need to be adjusted to handle multi-directional power flows. Where deployment of PV on distribution feeders may significantly exceed real-time demand, distribution system upgrades will be required. However, upgrades cannot be determined simply by evaluating grid requirements but must be configured to deal with existing and potential increases in PV deployments. Thus, the concept of "hosting capacity," much in the same way that Internet services calculate capacity requirements to serve Internet loads, will become a key decision criterion for future grid upgrades. Regulators will need to learn how hosting capacity is a relevant measure for grid planning and how cost justifications for rate purposes should be framed.

As noted, consumers are adopting renewable technologies and devices that enable them to manage their electricity use (e.g., through smart meters and energy management systems). Proactive consumers reduce demand pattern predictability, particularly when remote control of loads is involved. This complicates very near-term system planning, which, in turn, increases the need for redundancy to hedge the unexpected drops

[o] Frequency is the number of times per second that the electric charge reverses direction. "Electric Systems Respond Quickly to the Sudden Loss of Supply or Demand," *Today in Energy*, Energy Information Administration, November 21, 2011, http://www.eia.gov/todayinenergy/detail.php?id=3990.

[p] NERC defines inertia as "the ability of a machine with rotating mass inertia to arrest frequency decline and stabilize the system." See http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSTF_Draft_Concept_Paper_Sep_2014_Final.pdf.

[q] FERC issued a Notice of Inquiry on February 18, 2016, seeking comment on whether it should require all generators, including wind and solar, to provide frequency response service. See https://ferc.gov/whats-new/comm-meet/2016/021816/E-2.pdf.

and surges in consumption that can happen. Discussion of these circumstances and policy implications can be found in Chapter II (*Maximizing Economic Value and Consumer Equity*).

Visibility Is Key to Addressing the Changing Nature of Reliability

Flexibility in grid operations requires visibility into connected resources. Visibility—knowledge of "which resources are interconnected, as well as their locations and current capabilities"[80]—is a key attribute for managing the electricity system. Visibility is a necessary condition for managing rapidly changing and complex grid conditions and for providing awareness of incursions, as well as foresight for planning.

Advanced communication and information technologies facilitate visibility. Visualization requires data collection; analysis (e.g., modeling, business cases, etc.); transparency (i.e., sharing data and results); modeling (with both existing and new models); and deploying various sensing technologies, such as synchrophasors and smart meters. Creating foresight for transformation requires increasing visibility across many dimensions:

- *Temporal*—real time to planning
- *Geographic*—such as seams between balancing areas in the bulk electric system
- *Analytical*—identification and specification of computer models needed to evaluate the path to the future grid (such as finance tools, transmission planning tools, etc.)
- *Price*—the single most important mechanism for conveying information to customers and suppliers
- *Societal impacts*—associated risks taken on by the consumer may not be accounted for in price
- *Business*—business models and business-use cases for incumbent service providers and new technology providers
- *Technological*—including characteristics of new technologies and grid elements
- *Regulatory*—between different layers of jurisdiction and many different types of entities that must be synchronized to make the future grid work
- *Vertical industry boundaries*—between distribution and bulk system operations.

Integration of DER resources with ICT and other enabling technologies that provide visibility in the distribution system can give system operators the ability to react and respond to critical events with a level of efficiency and accuracy that is currently unavailable. Policies that comprehensively assess and manage DER could help reduce associated reliability challenges. At some level of DER penetration, these policies may merit extending to encompass the interstate bulk power system. Data requirements and visibility of assets (possibly including tracking production) are important policy issues for state regulators.

The deployment of innovative visibility technologies face multiple barriers that can differ by technology and the role each technology plays in T&D systems. For example, synchrophasors are an important new technology that increase T&D operator visibility, but technology dissemination is limited by utility concerns about vulnerabilities associated with sharing data and the fact that current regulations do not necessarily encourage investments in new technical solutions. This suggests that there is a role for the Federal Government in working with stakeholders and state regulators to identify, analyze, and develop recommendations for removing barriers to the deployment of value enhancing advanced technologies.

Growing Vulnerabilities for the Electric Grid

The electricity system requires management of risks from a wide variety of threats, each with different characteristics, not all of which are considered in a comprehensive way by decision makers. Threats and hazards to the electricity system represent anything that can cause disruption and outages, while vulnerabilities are points of weakness within a system that increase susceptibility to such threats. The physical vulnerabilities and specific risks to the electric power system vary among infrastructure components and by geographic location.

Significant Cost of System Outages

A National Research Council study of the 2003 blackout in the Midwest, Northeast, and Canada concluded that "the economic cost of the 2003 blackout came to approximately $5 per forgone kilowatt-hour, a figure that is roughly 50 times greater than the average retail cost of a kilowatt-hour in the United States."[r] Data suggest that electricity system outages attributable to weather-related events are increasing, costing the U.S. economy an estimated $20 billion to $55 billion annually.[s]

[r] National Research Council, *Terrorism and the Electric Power Delivery System* (Washington, DC: The National Academies Press, 2012), http://www.nap.edu/openbook.php?record_id=12050.

[s] Richard Campbell, *Weather-Related Power Outages and Electric System Resilience* (Congressional Research Service, August 28, 2012), R42696, http://www.fas.org/sgp/crs/misc/R42696.pdf.

Grid Reliability Risk

Reliability risk is a complex mix of natural and human threats. Risk mitigation includes developing future grid designs that maximize flexibility, as well as making investments in structural, process, and technology solutions, which increase grid resilience to reduce outage events. Some strategies can help reduce risks with respect to a variety of threats, while other strategies are more threat specific. Specific measures fall into a few broad categories—such as hardening (e.g., protection from wind and flooding), modernization (e.g., investment in sensors, automated controls, databases, and tools), general readiness (e.g., equipment maintenance, vegetation management, stockpiling of critical equipment), and analytics and security upgrades.[81, 82, 83]

Grid owners and operators are tasked with managing risks from a broad range of threats, defined as anything that can disrupt or impact a system—natural, environmental, human, or other. Many threats to critical electricity infrastructure are universal (e.g., physical attacks), while others vary by geographic location and time of year (e.g., natural disasters). Threats also range in frequency of occurrence, from highly likely (e.g., weather-related events) to less likely (e.g., electromagnetic pulse). Electric utilities have long prepared for specific hazards. However, hazards that evolve over time, or combinations of hazards that occur simultaneously, require enhanced or new measures for prevention or mitigation.[84]

Cyber attacks are emerging and rapidly evolving threats that may increase the vulnerability of utilities' system operations. Understanding the various established and emerging risks to the electricity system, including characterization of historical trends and future projections, as well as the predictability of different threats, has important implications for threat mitigation and resilience.[85] Figure 4-8 depicts the scope and severity of risks where probabilities of occurrence of each threat can change significantly "without notice." This figure illustrates the status of risk management with respect to current threats, some of which are expected to worsen in the future, suggesting a need for new risk management strategies. Current risk management practices are well suited to address common threats for most system components; however, the picture is mixed, particularly with respect to emerging threats, where there is limited data and experience. Figure 4-8 includes the current risks of system disruption (color coding) for electricity system segments (columns across) to various threats (by rows). The threats are further broken out by incidents of low and high intensity (rows). While the sector has well-established risk management practices for many current threats (indicated with filled circles), practices for other types of threats are nascent (open circles).

Figure 4-8. Integrated Assessment of Risks to Electricity Sector Resilience from Current Threats[86]

		System Components					
Threat	**Intensity**	**Electricity Transmission**	**Electricity Generation**	**Electricity Substations**	**Electricity Distribution (above)**	**Electricity Distribution (below)**	**Storage**
		Assessment of Risk & Resilience					
Natural/Environmental Threats							
Hurricane	Low (<Category 3)	Moderate ●	Low ●	Moderate ●	High ●	Low ●	Moderate ◑
	High (>Category 3)	High ◑	Moderate ●	Moderate ●	High ◑	Moderate ●	Moderate ◑
Drought	Low (PDSI>-3)	Low ●	Low ●	Low ●	Low ●	Low ●	Low ●
	High (PDSI<-3)	Low ●	Moderate ◑	Low ●	Low ●	Low ●	Moderate ◑
Winter Storms/Ice/Snow	High (PDSI<-3)	Moderate ●	Low ●	Low ●	Moderate ●	Low ●	Low ●
	Low (Minor icing/snow)	High ●	Low ●	Moderate ●	High ●	Low ●	Low ●
Extreme Heat/Heat Wave		Low ●	Moderate ◑	Moderate ●	Low ●	Low ●	Low ●
Flood	Low (<1:10 year ARI)	Low ●	Low ●	Low ●	Low ●	Moderate ●	Low ●
	High (>1:100 year ARI)	Moderate ●	Moderate ◑	Moderate ◑	Moderate ◑	Moderate ●	Moderate ●
Wildfire	Low (>Type III IMT)	Low ●	Moderate ●	Low ●	Low ●	Low ●	Low ●
	High (Type I IMT)	Moderate ●	Low ●	Moderate ●	Moderate ●	Low ●	Moderate ●
Sea-Level Rise		Low ●	Moderate ●	Low ●	Low ●	Low ●	Low ●
Earthquake	Low (<5.0)	Low ●	Moderate ●	Moderate ●	Moderate ●	Moderate ●	Moderate ●
	High (>7.0)	Moderate ●	High ●	High ●	Moderate ●	High ●	High ●
Geo-magnetic	Low (G1-G2)	Low ●	Low ●	Low ●	Low ●	Low ●	Low ●
	High (G5)	Low ○	Moderate ◑	High ○	Low ◑	Low ○	Moderate ◑
Wildlife/Vegetation		Low ●	Low ●	Low ●	Low ●	Low ●	Low ●

Levels of Risk

- ○ Low
- High
- Moderate
- Unknown

Current Status of Risk Management Practice

- ○ Nascent: critical vulnerabilities exist
- ◑ Established, but opportunities for improvement remain
- ● Well-established and robust

Threat	Intensity	System Components					
		Electricity Transmission	Electricity Generation	Electricity Substations	Electricity Distribution (above)	Electricity Distribution (below)	Storage
		Assessment of Risk & Resilience					
Human Threats							
Physical	Low	●	●	●	●	●	●
	High	◑	◑	◑	●	●	◑
Cyber	Low	◑	◑	◑	○	○	
	High	○	○	○	○	○	○
Electro-magnetic	Low (Ambient EMI)	●	●	●	●	●	●
	High (NEMP & HEMP)	●	○	○	●	●	○
Equipment Failure		●	●	●	●	●	●
Combined Threats		○	○	○	○	○	○

Levels of Risk

- ○ Low
- ● High (orange)
- ● Moderate (yellow)
- ○ Unknown (light blue)

Current Status of Risk Management Practice

- ○ Nascent: critical vulnerabilities exist
- ◑ Established, but opportunities for improvement remain
- ● Well-established and robust

Electricity system owners and operators must manage risks in a comprehensive manner for a broad range of threats. This chart provides an integrated portrait of current risks to the electricity system and the maturity of current risk management practices. The sector generally has well-established practices for managing familiar threats (e.g., wildlife), but much more work is needed to effectively manage risks from high-impact, low-frequency events (e.g., high-intensity hurricanes), combined threats, and unfamiliar threats for which information is lacking or unknowable (e.g., cyber and physical attacks). Additional attention is needed to reduce risks for above-ground distribution systems, substations susceptible to large-scale geomagnetic disturbances. This assessment does not reflect the status of risk management with respect to threats that are expected to worsen, such as extreme weather and cyber attacks. Acronyms: annual return interval (ARI), electromagnetic interference (EMI), high-altitude electromagnetic pulse (HEMP), nuclear electromagnetic pulse (NEMP), Incident Management Team (IMT), Palmer Drought Severity Index (PDSI).

Grid Operator Reliability Risk Management Is Increasingly Important

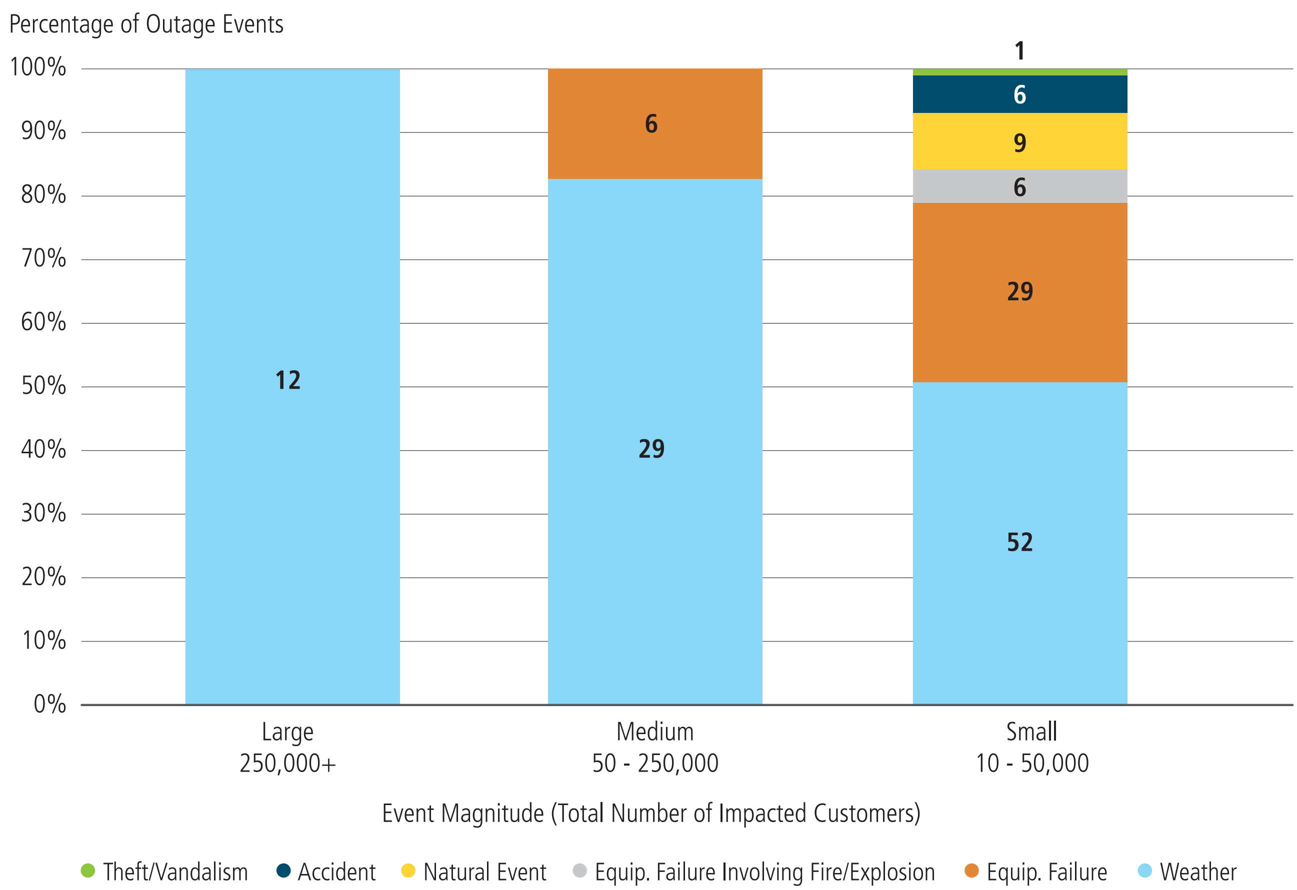
Delivery system reliability remains high and robust in today's world, but emerging threats create a higher risk profile that, in turn, creates challenges for ensuring sustained high delivery system reliability. There are many electricity sector risks that are continuously managed, such as investment risks, regulatory risks, and grid operational risks. Operational risks encompass all variables that can produce outages or disrupt frequency and voltage—from new types of power generation, to changing customer behavior, to extreme weather. Despite risk management practices, the risk of system disruption remains particularly high to certain system segments (e.g., above-ground distribution systems) or threats (e.g., large-scale earthquakes). Further, there remain evolving or dynamic threats for which the levels of risk are unknown and the risk management practices could be improved (e.g., high-intensity physical attacks, high-intensity cyber attacks, or combined threats).

Key policy questions include how investments should be prioritized, how cyber threats to ICT infrastructure should be managed, how emerging climate threats should be mitigated and planned for, and whether a highly dispersed power supply system contributes to a more resilient and secure electricity sector. Finally, longstanding high-voltage transmission and baseload power supply assets now must be analyzed as possible insurance assets for reliability

Extreme Weather Is a Leading Threat to Grid Reliability

Some types of extreme weather are becoming more frequent and intense due to climate change, and these trends have been the principal contributors to an observed increase in the frequency and duration of power outages in the United States between 2000 and 2012.[87] Figure 4-9 summarizes the main sources of contemporary outage events in 2015, excluding consideration of cyber-related effects.

Figure 4-9. U.S. Electric Outage Events by Cause and Magnitude, 2015[88]

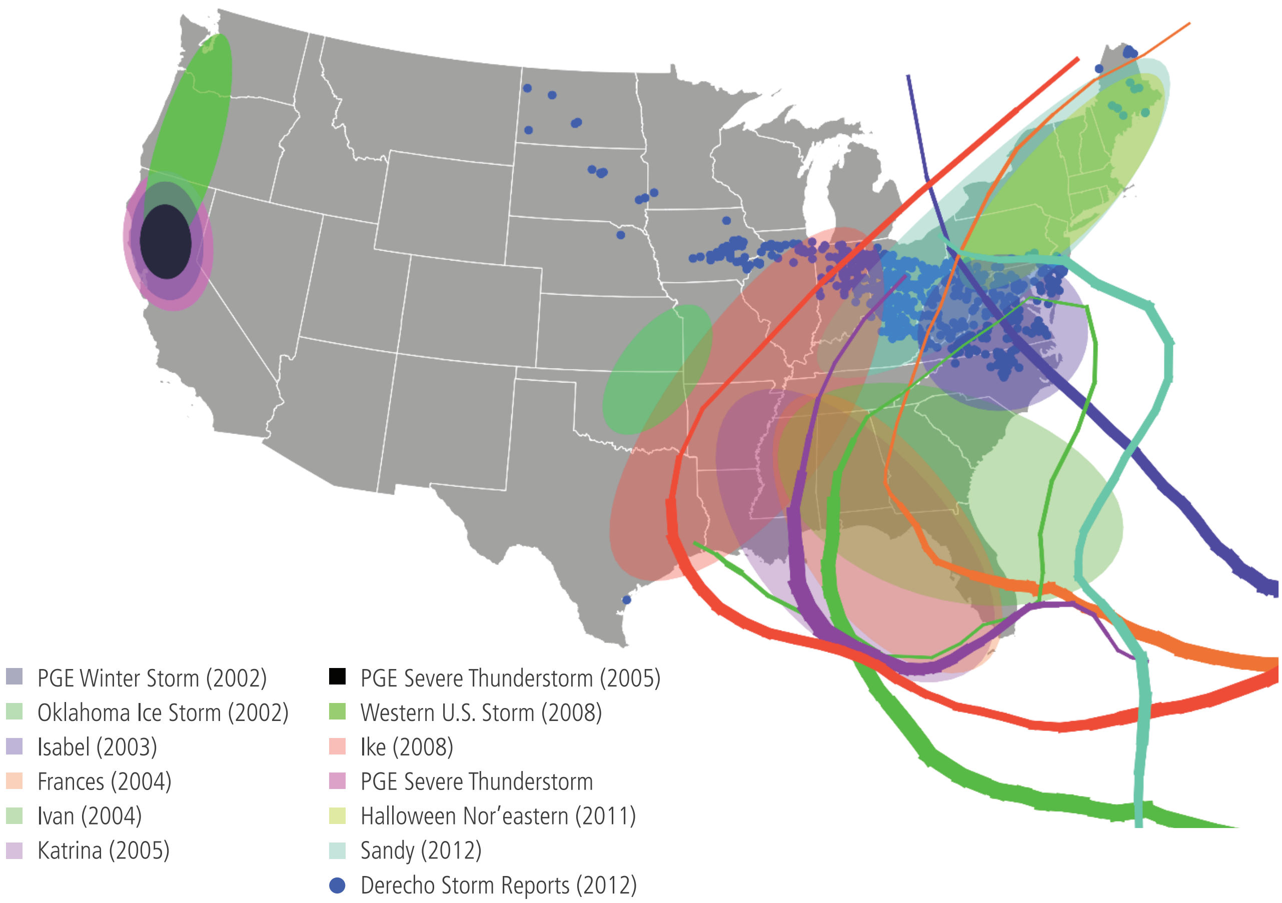


Extreme weather is the leading cause of electric power outage events, especially for the most significant disruptions. All 12 of the large-scale events in 2015 were weather related, while just over half of the small-scale events were caused by weather.

Superstorm Sandy demonstrated the severe impacts of a large storm and the interdependencies of electricity and other infrastructures. The storm knocked out power to 8.66 million customers from North Carolina to Maine and as far west as Illinois and Wisconsin. Electric utilities deployed over 70,000 workers to the affected areas, the largest-ever dispatch of utilities workers.[89] The nearly 1,000-mile-diameter storm caused flooding and power outages that shut down many other major infrastructure components, illustrating the dependence of other critical infrastructures on electricity.[90] Oil refineries were shut in, as well as many East Coast product import terminals—which act as the primary backup method for securing bulk product supplies during refinery outages—due to the loss of power. A week after the storm, product deliveries in New York Harbor had returned to only 61 percent of pre-storm levels, and less than 20 percent of gas stations in New York City were open for business. The Department of Defense provided 9.3 million gallons of fuel, though fuel shortages still greatly hindered the ability of emergency response personnel to respond to the crisis.[91]

Weather-related events, including lightning and storms, have historically posed the greatest operation risk to the electricity system.[92] Strong winds, especially hurricane-force winds, are the primary cause of damage to electric T&D infrastructures. Failures on the distribution system are typically responsible for more than 90 percent of electric power interruptions, both in terms of the duration and frequency of outages.[93] Damage to the transmission system, while infrequent, can result in more widespread major power outages that affect large numbers of customers and large total loads.[94] Figure 4-10 summarizes major weather-induced reliability disruptions from 2002 to 2012.

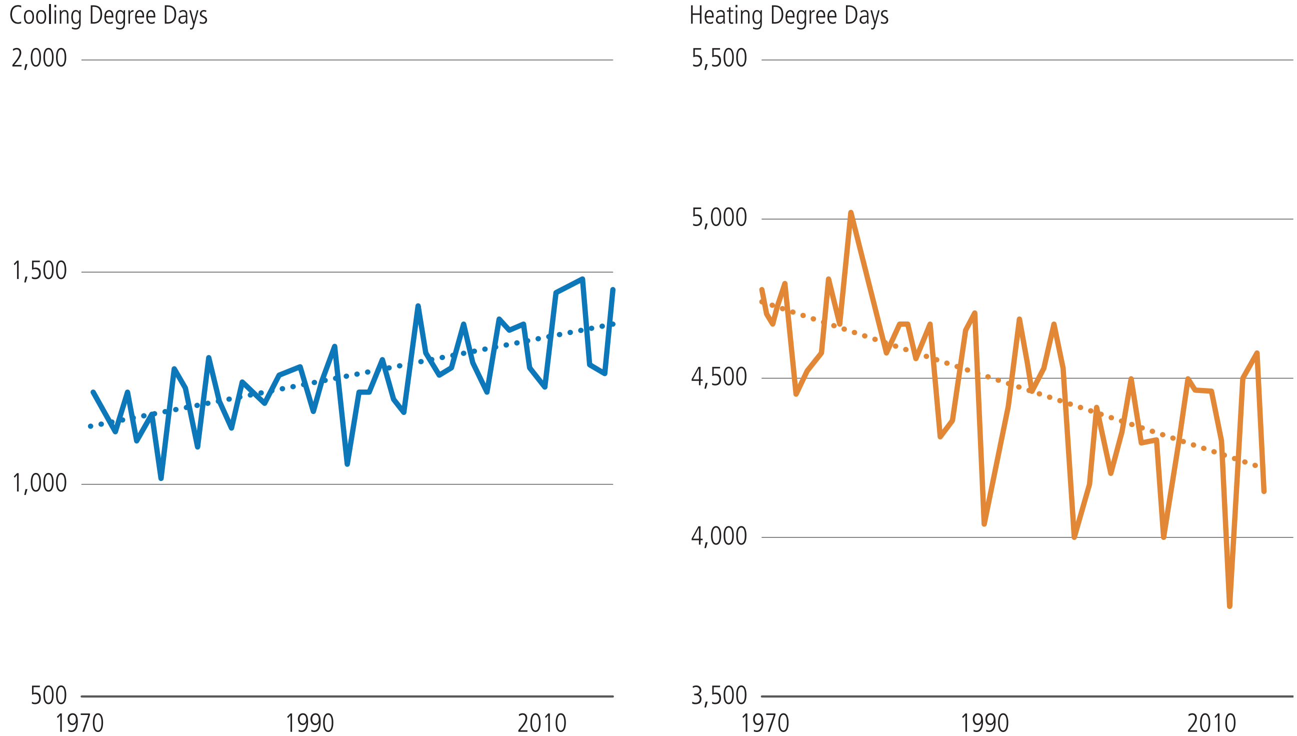
Figure 4-10. Major Weather-Related Outages Requiring a National Response, 2002–2012[95, 96]



There are regional variations in outage causes in the United States. While the East and Gulf Coast regions are subject to hurricanes, large, weather-related outages in the West are more often caused by winter storms. Major outages from weather events are more common than from cascading failures.

Further, 2016 is on track to be the third consecutive year of record-breaking global temperatures.[97] Cooling degree days[t] have already increased in the United States by roughly 20 percent over the last few decades (Figure 4-11), and this trend is projected to continue in the future.[98] These changes in temperature are expected to result in increased electricity use, particularly during the mid- to late-afternoon peak hours, primarily to meet rising demand for air conditioning.[99]

Figure 4-11. Heating and Cooling Degree Days in the Contiguous 48 States, 1970–2015[100]



As air temperature continues to rise, since 1970, the number of cooling degree days has increased in the United States by roughly 20 percent, while the number of heating degree days has declined.

The maps in Figure 4-12 show projected median changes in cooling degree days by 2040 under two global greenhouse gas emissions scenarios, based on analysis of output from several global climate models,[u] which were downscaled to the county level.[101] This analysis found that while the average American has historically experienced around 2 weeks of days over 95°F each year, this could rise to 3 to 6 weeks, on average, by 2040.[102]

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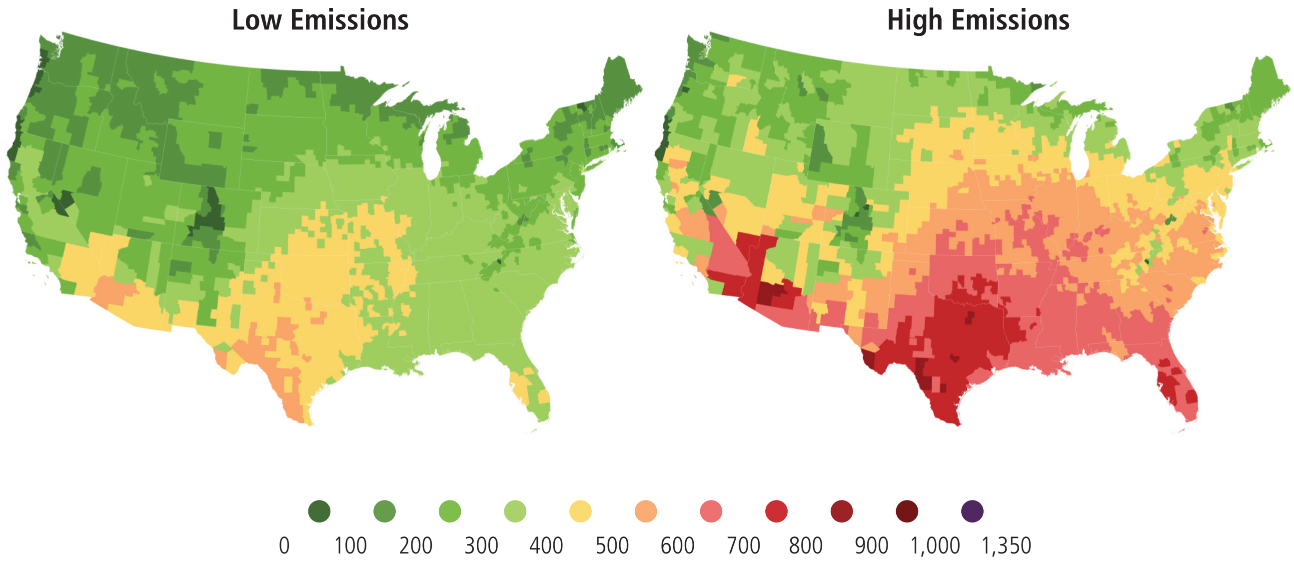
[t] The number of degrees that a day's average temperature is above 65° Fahrenheit, indicating that consumers need to use air conditioning to cool their buildings, and there is an increase in electricity demand.

[u] To account for uncertainty surrounding future emissions pathways, the study cited here uses a plausible range of scenarios developed for the Fifth Assessment Report of the Intergovernmental Panel on Climate Change. The highest emissions scenario corresponds to a world where fossil fuels continue to power global economic growth. The lowest emissions scenario reflects a future in which global greenhouse gas emissions are reduced through a rapid transition to low-carbon energy sources.

Figure 4-12. Median Change in Cooling Degree Days from Historical (1981–2010) Average for Average Year under Two Emissions Scenarios, 2030–2049[103]



The average number of cooling degree days are expected to increase significantly by 2040, particularly in southern parts of the country. Projected changes for the higher emissions scenario (*right panel*) are much greater than under the lower emissions scenario (*left panel*).

Power sector system costs increase with higher temperatures, particularly as additional capacity is built to meet higher peak demand.[104] Higher air temperatures also reduce the generation capacity and efficiency of thermal generation units.[105] Both factors were taken into consideration by modeling conducted for the QER. Models showed the likely range of total temperature-related power system costs[v] increasing by 2 percent to 7 percent (with a median value of 4.5 percent) under the lowest greenhouse gas emissions scenario, rising to 4 percent to 11 percent under the highest emissions scenario.[106] The scale of these modeled costs illustrates why electricity system planners should consider how best to incorporate projected changes in climate into load forecasting and other considerations that affect investment planning for the electric power sector. Increased earth observation and modeling of local-scale climate effects to improve forecasting would benefit electricity system planning and could reduce costs.

Extreme temperatures also increase the potential for electrical equipment to malfunction. For example, transformers do not last as long when overloaded to meet peak demand, particularly when they are simultaneously exposed to high temperatures that exceed the heat ratings for which they were designed.[107] When planning for future investments, it may become important for utilities to proactively invest in transformers with higher heat ratings to reduce the potential for overloading under future, warmer conditions.

A continuation of sea-level rise, in conjunction with storm surges caused by tropical cyclones, hurricanes, and nor'easters, will increase the depth and the inland penetration of coastal flooding, thus increasing the frequency with which electricity assets are exposed to inundation during storm events.[108] These challenges are exacerbated by the fact that some coastal areas may be experiencing load growth—rapid population growth and development in coastal areas—which is expected to continue in the coming decades.[109, 110]

Another aspect of uneven impacts is that low-income and minority communities are disproportionately impacted by disaster-related damage to critical infrastructure.[111] These communities often do not have the means to mitigate or adapt to natural disasters, and they disproportionately rely on public services, including community shelters, during disasters. As a result, there may be a Federal role in providing technical and

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[v] Calculated in net present value terms, between 2016 and 2040, using a 5 percent discount rate.

financial resources to help states and localities prioritize resilience investments in critical public infrastructure that would protect the most vulnerable communities.

Electricity and Natural Gas System Interdependencies

A key interdependency (and vulnerability) for all economic sectors and critical infrastructures is reliance on electricity, making its reliability a fundamental need and requirement across the entire economy. Many of these interdependencies are growing, such as the interdependency of electric and natural gas systems.

The reliability of the Nation's electricity system is increasingly linked to the reliability of natural gas pipelines and associated infrastructure. On May 24, 2016, NERC released a special assessment of gas-electric interdependencies, which included an investigation of the potential reliability risks to the Nation's bulk power system due to increased reliance on natural gas. NERC found that areas with growing reliance on natural gas–fired generation are increasingly vulnerable to gas supply disruptions. These concerns were reinforced by NERC's latest long-term reliability assessment, which was released in December, 2016.

Unlike other fossil fuels, natural gas is not typically stored onsite and must be delivered as it is consumed.[w] In many regions, sufficient gas infrastructure is a key requirement for electric reliability. An interruption in natural gas deliveries could result from extreme weather or *force majeure* events, as well as from low-probability events that could unexpectedly remove infrastructure from service, such as a well malfunction, as seen in the underground storage leak in Aliso Canyon, California. Extreme weather events, such as in the Southwest outages of 2011, can simultaneously increase energy demand for gas and electric heating, while reducing supplies in the affected region.[112] Operators may be able to respond to disruptive events by rerouting gas onto other pipelines, as was the case during a 2016 disruption to the Texas Eastern Pipeline.[113] Electric curtailments also have the potential to reduce gas available to gas-fired generators. For example, in 2011, power outages disabled electric-powered gas compressors on well gathering lines, which reduced supplies of natural gas to New Mexico.[114] In addition to physical natural gas disruptions' impact on the electricity system, the electricity sector's increasing reliance on natural gas raises serious concerns regarding the need to secure natural gas pipelines against emerging cybersecurity threats. Thus, the adequacy of cybersecurity protections for natural gas pipelines directly impacts the reliability and security of the electric system.

The vulnerabilities due to natural gas and electric system interdependency are the subject of ongoing regulatory reforms, physical upgrade efforts, and industry collaboration. Some ISOs have undertaken surveys of critical gas facilities to ensure that these facilities are exempt from potential load-shedding plans in the event of a system emergency, and FERC has allowed communication of proprietary and other non-public operational information between the gas and electric industries to continue in order to facilitate further sharing of critical reliability issues.[115] To date, many stakeholders have performed extensive analysis to improve real-time and near-term operations and planning in order to address natural gas–electricity interdependencies. One result has been FERC issuing a final ruling requiring interstate natural gas pipelines to change their pipeline nomination schedules to better conform to dispatch scheduling in organized electricity markets.[116] Most coordination efforts have been focused on short-term planning and operations. Mid- and long-term planning coordination is also being explored to properly plan for long-term assets like electric transmission and natural gas pipelines. However, coordinated long-term planning across natural gas and electricity can be challenging as the two industries are organized and regulated differently.

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[w] Some natural gas power plants also have the ability to operate on alternatives to pipeline-delivered natural gas, such as fuel oil and local stores of liquefied natural gas or liquefied petroleum gas. In addition, note that potential deliverability challenges for coal have also been documented. For example, see Tim Shear, "Coal Stockpiles at Coal-Fired Power Plants Smaller than in Recent Years," *Today in Energy*, Energy Information Administration, November 6, 2014, http://www.eia.gov/todayinenergy/detail.cfm?id=18711. See also Department of Energy (DOE), *Natural Gas Infrastructure Implications of Increased Demand from the Electric Power Sector* (Washington, DC: DOE, 2015), v, http://energy.gov/epsa/downloads/report-natural-gas-infrastructure-implications-increased-demand-electric-power-sector.

Underground Storage Leak in California Driving Natural Gas Storage Safety and Reliability Improvements[x]

On October 23, 2015, the largest methane leak from a natural gas storage facility in U.S. history was discovered by the Southern California Gas Company at well SS-25 in its Aliso Canyon Storage Field in Los Angeles County. The leak continued for nearly four months until it was permanently sealed on February 17, 2016. In the interim, residents of nearby neighborhoods experienced health symptoms consistent with exposure to odorants added to the gas; thousands of households were displaced; and the Governor of California declared a state of emergency for the area. Approximately 90,000 metric tons of methane were released from the well, although estimates vary, and the State of California is continuing its analysis. The incident also created serious energy supply challenges for the region and prompted broader public concerns about the safety of natural gas storage facilities.

From an electric reliability perspective, the continued shutdown of this facility has been significant because it is a key component of the Southern California gas system serving customers in the Los Angeles Basin and San Diego, particularly many gas-fired power plants. Curtailments of gas deliveries were expected to cause electric reliability problems in the summer of 2016. Such disruptions were avoided, however, due to the combined effects of comparatively mild summer weather, intensified electric demand response efforts, coordinated maintenance programs, and extraordinary management of the region's gas delivery system. The possibility of gas and electric delivery problems remains a concern, however, for the winter of 2016–2017, and additional preparation and coordination are required in order to avoid gas and electric curtailments.

In April 2016, the Obama Administration convened an Interagency Task Force on Natural Gas Storage Safety to support state and industry efforts to ensure safe storage of natural gas. Congress codified the Task Force through the Protecting our Infrastructure of Pipelines and Enhancing Safety Act, which was signed into law by President Obama in June 2016. The legislation created a task force established by the Secretary of Energy that consists of representatives from the Department of Transportation, Environmental Protection Agency, Federal Energy Regulatory Commission, and the Department of the Interior. The Protecting our Infrastructure of Pipelines and Enhancing Safety Act tasked the group with performing an analysis of the Aliso Canyon event, making recommendations to reduce the occurrence of similar incidents in the future, and required that Pipeline and Hazardous Materials Safety Administration promulgate minimum safety standards for underground gas storage that would take effect within 2 years.

In October 2016, the Task Force released a report, called "Ensuring Safe and Reliable Underground Natural Gas Storage," and 44 recommendations. These recommendations address concerns regarding the integrity of wells at underground natural gas storage facilities, public health and environmental effects from leaks like the one at the Aliso Canyon facility, and energy reliability concerns that could arise in the case of failures at such facilities in the future.

[x] Interagency Task Force on Natural Gas Storage Safety, *Ensuring Safe and Reliable Underground Natural Gas Storage* (Washington, DC: Department of Energy, October 2016), https://www.energy.gov/sites/prod/files/2016/10/f33/Ensuring%20Safe%20and%20Reliable%20Underground%20Natural%20Gas%20Storage%20-%20Final%20Report.pdf.

Combined Threats to the Grid

The stochastic nature of certain events such as hurricanes and earthquakes makes the probability of two closely spaced, co-located events very low. However, an intelligent attacker may plan to use the occurrence of one naturally occurring, high-intensity, and low-frequency event to amplify the impact of a physical, cyber, or electromagnetic pulse attack.[117] While electric power systems are generally resilient and quick to recover from failures caused by most natural and accidental events, the National Academy of Sciences concluded that an intelligent multi-site attack by knowledgeable attackers targeting specialized components, like power transformers, could result in widespread, long-term power outages from which it could take several weeks to recover.[118] Another combined threat is the simultaneous occurrence of a severe heat wave during a prolonged drought,[119] which is expected to become increasingly likely in certain regions, such as the U.S. Southwest.[120]

Physical Attacks on the Grid

Incidents such as a series of as-yet unexplained attacks on exposed electricity substations—including the Metcalf incident in California and the attack on the Liberty substation in Arizona—have raised the public's consciousness about the vulnerability of the U.S. electricity grid and the need for the United States to address these vulnerabilities. With an increased focus on physical security, NERC developed Critical Infrastructure Protection (CIP) Standards (CIP-014) in 2014 to address the physical security risks and vulnerabilities of critical facilities on the bulk power system.[121] The Reliability Standard requires transmission owners that meet specific voltage criteria to identify and then protect facilities that, if rendered inoperable or damaged, could result in instability or uncontrolled separation within an interconnection. Transmission owners must also complete third-party verification of their analyses and mitigate the identified areas of concern. Per NERC, the initial risk assessments of critical facilities (including transmission stations, substations, and control centers) were completed by October 1, 2015, while the third-party review of proposed changes to security plans and mitigation strategies was to be completed by November 24, 2016.[122] All entities subject to NERC CIP-014 Standards must retain data and/or evidence of compliance, as described by NERC guidance.[123]

Evolving Cyber Threats to the Grid

The integration of cyber assets to electricity infrastructure presents unique and significant challenges for maintaining and planning for reliable and resilient grid operations. The current cybersecurity landscape is characterized by rapidly evolving threats and vulnerabilities juxtaposed against the slower-moving prioritization and deployment of defense measures. This gap is exacerbated by difficulties in addressing vulnerabilities in operational technologies that cannot easily be taken offline for upgrades, the presence of significant legacy systems, and components that lack computing resources to incorporate new security fixes. Also, any operational changes must be implemented by the thousands of private companies that own and operate electricity infrastructure.

Sector transformation based on a two-way flow of energy and information between grids and consumers brings to the foreground the importance of Federal Government engagement in helping to manage and mitigate vulnerabilities inherent in 21st-century modernization. Interoperability standards, in particular, have the potential to enhance cybersecurity. Improved tools, analytic methodologies, and demonstrations would serve to clarify the circumstances where improved interoperability can improve grid cybersecurity by standardizing security solutions such that utilities can select "plug-and-play" options to mitigate cybersecurity issues. To this end, there is a role for the Federal Government to facilitate state and utility adoption of interoperability standards that provide high societal net benefits through providing high-quality and trusted information to decision makers.[124]

While cyber attacks on the U.S. grid and affiliated systems have had limited consequences to date, attacks across the globe on energy systems should be viewed as indicators of what is possible. Threats can emerge from a range of highly capable actors with sufficient resources, including individuals, groups, or nation-states under the cloak of anonymity.

As noted, the 2015 cyber attack on the Ukrainian electric grid was the most sophisticated cyber incident on a power system to date. On December 23, 2015, Ukraine experienced widespread power outages after malicious actors remotely manipulated circuit breakers across multiple facilities in a series of highly coordinated attacks.[125] The event compromised six organizations, including three electric distribution companies; disconnected seven 110 kilovolts and 23 35-kilovolt substations (which would straddle Federal and state jurisdiction in the United States); rendered equipment inoperable; overwhelmed the call center with a denial-of-service[y] event to prevent people from reporting outages; and left 225,000 without power for 1 to 6 hours.

[y] Distributed denial of service refers to the prevention of authorized access to multiple system resources or the delaying of system operations and functions.

Grid Communication and Control Systems

Deploying smart grid technologies can support increased grid systems' observability and reliability by allowing more real-time awareness via sensors, which enable self-healing systems like fault location and service restoration. At the same time, deployment of smart technologies and DER can provide new vectors for cyber attacks. While not yet a significant issue, this is a growing and significant concern in a grid with two-way, end-to-end flows of electricity. While the likelihood that a malicious actor could bring down large regions of the electric grid by manipulating distributed energy and behind-the-meter equipment is currently low, the risks may change as distributed energy and other advanced technologies increase in number, are operated in aggregation, and are used by the bulk power system to manage and shape load. Smart meters track detailed power usage and allow for two-way communication between the utilities and end users via smart grid technology, which can include remote customer connection and disconnection. Hackers targeting this technology could cause erroneous signals and blocked information to cut-off communication, cause physical damage, or more, and disconnect large numbers of customers to disrupt the grid.

Recently, some utilities have been moving toward combining their physical security and cybersecurity business centers to create a "centralized operations center" organized under a chief information security officer responsible for cybersecurity.[126] These centralized operations centers generally work toward meshing informational technologies with physical operational technologies. Other utilities have their cybersecurity risk management program located in existing information technology (IT) security departments.[127] However, some utilities suffer from a lack of practical cyber expertise. A recent survey showed that 37 percent of utilities surveyed make cybersecurity decisions at the executive level, 47 percent at the management level, and only 16 percent by professional staff.[128]

Reported cybersecurity incursions into industrial control systems (ICS) within the U.S./Canadian energy sector, have decreased slightly, from 111 reported incidents in 2013,[129] to 79 incidents in 2014,[130] and 46 in 2015.[131] This is occurring despite an overall increase in the number of reported ICS incidents across the broader economy, and so far, these incursions have been unsuccessful at inhibiting or disrupting power system operations.[132] Typical cybersecurity events impacting the grid have been mainly limited to gaining access to networks through phishing emails or infecting flash drives with the hope that they will be connected to a network. Russian hacking of utility systems as seen in the Ukraine incident, however, underscores that such events should not be viewed simply as information theft for business purposes. The more common cyber intrusions impacting the electricity subsector today could be preparatory activity for disruptive attacks in the future.

Mitigation of Threats to the Grid

Detecting anomalies and sharing information across organizations are critical measures to enhance grid security; this covers everything from prevention to mitigation and recovery from cyber attacks. However, it is difficult to identify cyber intrusions when no changes or disruptions to system operations are evident or detectible. Furthermore, utilities report a lack of intrusion detection systems,[133] which allow security personnel to identify anomalies in cyber systems and to obtain forensic data.[134] Organizations vary monitoring systems, and nearly every utility will require distinct intrusion detection system specifications due to utility-specific IT and operational technology system configurations.[135, 136]

Even in optimized detection environments, programs and institutions that wish to facilitate sharing within and across industry and government face challenges, including human delays in sharing information, procedural barriers related to classified information, and liability and privacy concerns from industry that inhibit sharing. For example, Federal agencies maintain classified information related to cyber and physical security threats. While some of this information is shared via existing mechanisms, including the Electricity

Information Sharing and Analysis Center and DOE's Cybersecurity Risk Information Sharing Program,[z] sector representatives routinely ask for more in-depth, synthesized, and timely security information.

When digital components of the grid have been compromised, manual operations[aa] can be a temporary alternative. Utilities may need to maintain mechanical controls to prevent degradation and loss of operability.[137] Some subject matter experts suggest utilities are also leveraging decades of experience with mutual assistance agreements to set up cyber assistance in the event of a cyber attack, but response and recovery from cyber attacks pose distinct challenges that are generally not covered by existing mutual assistance programs. The Electricity Subsector Coordinating Council established the Cyber Mutual Assistance Task Force to convene industry experts and develop a cyber mutual assistance framework. The Federal Government could play a convening role for the electricity sector and thereby accelerate efforts to design and employ cyber mutual response programs and ensure swift grid recovery after a cyber attack.

Grid Cybersecurity Workforce Gaps

A shortage of skilled cybersecurity personnel across government and electricity industry presents challenges to meeting response and recovery needs in the aftermath of a large, disruptive cyber event. The power grid is a cyber-physical system, requiring a cross-disciplinary workforce dedicated and trained to design, manage, and protect such complex systems.[138] Companies face challenges in designating sufficient personnel for system security.[139] In addition to the challenge of incorporating sufficient cyber and physical security expertise into their businesses, recruiting and maintaining a workforce that is adequately trained is a growing challenge. To address emerging cybersecurity risks, the United States requires a workforce adept in a variety of skills, such as risk assessment, behavioral science, and familiarity with cyber hygiene.[ab]

Smart Grids and Related Risk

Deployment of smart grid technologies—sensors and the ability to collect and analyze more data faster—supports increased observability of grid systems and thereby contributes to increasing grid reliability. However, in the absence of adequate cyber protections, deployment of smart technologies and DER could increase system vulnerabilities. Because the deployment of these technologies is still in the relatively early stage, electricity regulatory bodies should ensure that cyber protection planning includes advanced cyber protection protocols when execution occurs.

Automated smart meters, for example, are increasingly relied on to track actual power usage and allow for two-way communication between the utilities and end users. Hackers targeting this technology could cause disrupted power flows, create erroneous signals, block information (including meter reads), cut off communication, and/or cause physical damage. Also, some supervisory control and data acquisition (SCADA) systems rely on modern communication infrastructure or a blend of modern and conventional, (i.e., telephone lines communication channels to achieve the same ends), which could make SCADA communications more accessible to hackers and more vulnerable to disruptions. Hacking may come through access to hardcoded

[z] In partnership with industry, the Department of Energy's Office of Electricity Delivery and Energy Reliability has been supporting the Cybersecurity Risk Information Sharing Program (CRISP), which is a collaborative effort with private energy sector partners to facilitate the timely sharing of threat information and the deployment of situational awareness tools to enhance the sector's ability to identify threats and coordinate the protection of critical infrastructure. In August 2014, the North American Electric Reliability Corporation and the Electricity Subsector Coordinating Council agreed to manage CRISP for its sector.

[aa] Use of mechanical switches and controls rather than computer-based controls.

[ab] Cyber hygiene is a set of practices designed to maintain cyber security and keep out the "bugs" from a digital system. Just as hand washing keeps germs from entering the body, practices such as deleting data from cloud storage when it is no longer needed or prohibiting the download of non-essential applications, which might contain viruses, are intended to keep intrusions out of a computer system.

passwords,[ac] system backdoors,[ad] passwords in clear text,[ae] lack of strong authentication,[af] and firmware vulnerabilities.[ag, 140, 141]

Development of Security Metrics

A major impediment to common metrics is variation in how to measure benefits (or conversely, the cost of interruptions), such as "freight cost per mile" or "value at risk." After the attack on the Metcalf substation in April 2013, the California Public Utilities Commission analyzed methods of quantifying distribution system security.[ah] Metrics included copper theft, successful or unsuccessful intrusion or attack, and false or nuisance alarms; the condition of all monitoring equipment and the performance of security personnel in training exercises and on tests; results of substation inspections; instances of vandalism or graffiti; and problems with access control, number of malfunctions of security equipment, or camera coverage.

[ah] Ben Brinkman, Connie Chen, Arthur O'Donnell, and Chris Parkes, *Regulation of Physical Security for the Electric Distribution System* (California Public Utilities Commission, February 2015), http://docplayer.net/816940-Regulation-of-physical-security-for-the-electric-distribution-system.html.

Comprehensive Vulnerabilities Assessments

Reliability requirements in the face of human and natural threats require enterprises, as well as state and Federal entities, to seriously assess vulnerabilities and prioritize investments to ensure that highly reliable service continues. These entities diligently work to identify and mitigate risks to grid reliability. However, given the scope and complexity of risks, especially related to new vectors such as cyber attacks, there may be a need to improve coordination not only around assessing event outcomes, but also around maintaining contemporary assessments of vulnerabilities, their associated risks, and professional estimates of their likelihood.

Gaps in National Reliability, Security, and Resilience Authorities and Information

The primary Federal entities with roles related to security and resilience of the electric grid under normal and emergency conditions are DOE, the Department of Homeland Security (DHS), the Department of Commerce, and FERC.[142] These entities' roles span research and development, standards and guidance, information-sharing mechanisms, and the coordination of resource deployment during emergency events.

Existing authorities cover a wide breadth of Federal Government responsibilities, yet certain gaps remain in implementing comprehensive reliability, security, and resilience measures. For example, the Fixing America's Surface Transportation (FAST) Act granted the President new authorities to protect critical infrastructure against electromagnetic pulse, cyber, geomagnetic disturbances, and physical threats, but not to take anticipatory action for natural disasters and extreme weather. Nevertheless, certain extreme weather events (e.g., heat waves, hurricanes) can be easier to anticipate,[143] and to date, they have caused significantly more

[ac] Passwords that cannot be changed by the user.

[ad] Alternative access (to secure data or functions) that bypass normal security procedures.

[ae] Passwords stored without encryption.

[af] Not scrambling login information, which enables a digital eavesdropper to capture passwords.

[ag] Generic catch-all for hardware-based exploits (rather than software-based).

direct physical harm to the electric grid than have malicious acts. Taking actions in advance of an impending threat can have significant positive effects in reducing power outages,[144] so extending this authority for all hazards would be a great benefit for protecting the grid.

The lack of access to data represents another challenge to Federal agencies to enhance the security and resilience of the grid. Given that the majority of electricity infrastructure is privately owned, the Federal Government must rely on industry data collection activities to understand the vulnerability and security landscape of the electric grid. Furthermore, as noted earlier, utilities report SAIDI, SAIFI, and CAIDI statistics in inconsistent ways,[145, 146] limiting the ability of governments to independently conduct robust risk assessments of the grid. DOE and FERC in particular lack access to data on critical grid assets and their vulnerabilities. In order to support the President in executing new anticipatory security authorities under the FAST Act, addressing this information deficit is a priority.

NERC collects certain data in its role of performing grid reliability assessments and supporting the development of reliability and security standards, but NERC does not make all of that data available to government agencies. DOE has some limited visibility into critical electricity infrastructure through tools like EAGLE-I;[ai] additional system data—to determine, for example, where there are critical vulnerabilities—are needed to exercise the new emergency authorities granted to the President and the Secretary of Energy under the FAST Act.

One of the most prominent examples of this data gap is a lack of information on risk mitigation practices at the utility level, including information regarding participation in risk mitigation programs, a utility's specific risk mitigation practices, and spare equipment specifications and numbers for critical infrastructure, such as transformers. With enhanced and appropriately protected data on utility practices, component part reserves, and an increase in awareness on a range of additional topics—such as transformer configuration, the direct current resistance of various components, and substation grounding resistance values—DOE's ability to understand the extent to which infrastructure will be improved can enable DOE to better fulfill key statutory and executive responsibilities.

Markets and Their Impact on Reliability and Resilience

Centrally organized wholesale markets are recent innovations in the century-plus life of the electricity sector. They were developed and implemented beginning in the 1990s on the heels of state legislative and regulatory direction, but are considered Federally regulated structures that adhere to rules set by FERC and reliability standards set by NERC. Centrally organized markets operated by ISO/RTO include time-delineated markets (e.g., day-ahead, hour-ahead, and real-time), as well as system support services such as spinning reserve and non-spinning reserve, often referred to as Ancillary Services. Commodity exchanges, such as the Intercontinental Exchange (ICE) and the New York Mercantile Exchange, offer future contracts for location-specific electricity trading (referred to as hubs in U.S. markets). These short-term markets are designed to provide price discovery on the marginal cost of power production and delivery.

Seven U.S. regions have operating ISOs/RTOs that manage centrally organized wholesale markets for energy trades (i.e., MW-hour only, as compared to capacity trades that are for MW-only transactions). Together, these trades play an important role in operating and economically optimizing regional grids and ultimately delivering fair-priced electricity to the Nation's consumers. Aspects of the bilateral model exist in the RTO/ISO regions, particularly in the SPP and Midcontinent ISO. Also, several RTO/ISOs operate ancillary services

[ai] EAGLE-I, which stands for Environment for Analysis of Geo-Located Energy Information, is an interactive geographic information system created and managed by the Department of Energy. It allows participants to view and map the Nation's energy infrastructure and obtain near real-time informational updates concerning the electric, petroleum, and natural gas sectors within one visualization platform.

markets and some run capacity markets designed to help ensure that total electricity resources will be sufficient to meet the immediate demand for electricity.

Wholesale electricity trade occurs through bilateral transactions and are predominant in the Southeast and non-California West. These transactions vary in duration of contract, as well as in volume, daily timing, and duration of delivery. Trade differs regionally as a function of distinctive characteristics of regional grids. Bilateral trade volumes tend to be much larger than daily trade in ISO/RTO short-term markets.

There are many reasons that wholesale markets developed—from requirements for open-access transmission systems, which enable development of competitive power generation, to the need to value resources in more refined ways, which help ensure that system reliability is maintained across a broad spectrum of possible disruptive situations. For example, peak mitigation requires generators to perform differently than a traditional baseload production model might specify, and therefore, it may be more valuable than day-ahead committed baseload generation. Increasingly, frequency regulation is as important as peak mitigation, but frequency regulation methods may differ at the transmission level compared to the distribution level.

As noted, an array of new and evolving business models—aggregators, consumer generators, and an evolving generation mix—have emerged from the adoption and integration of new technologies and their associated economics. These developments are raising jurisdictional and market questions. For instance, at the bulk power (wholesale) level, regulators deem short-run markets as workably competitive, but concerns have been raised about the ability of short-run markets to address longer-term issues, such as ensuring that adequate capacity will be available when needed. Also, wholesale markets have successfully integrated independent generation into system operations, and efforts have been underway for some time to make individual DER providers (principally DR) and aggregators of DER (also principally DR) active market participants. More visibility of and reliance on these potential resources is needed, however, to maximize their value.

At the local and utility level (retail), electricity choice markets that are intended to bring new services and lower prices to consumers have seen minor successes, and consumer demand for these services is a significant driver of change. Some states are exploring new structures that would open retail commodity trade to markets. These models are under consideration in the State of New York, for instance, and are often referred to under the rubric Distribution System Operator models.

Centrally Organized Wholesale Markets and Reliability

Electricity production and delivery have traditionally been organized around large centralized power stations and high-voltage transmission lines. Power is shipped over long distances before voltage is stepped down to flow through distribution systems for delivery to consumers. This system often is referred to as the "bulk power system." Centrally organized wholesale markets are structured to provide price discovery of wholesale electricity costs in the bulk power system. Costs relating to bulk power are more than half—and up to two-thirds—of most customers' electricity bill. The significance of costs to customers and the associated economic value of electricity to them is why the functioning of wholesale markets is so important to the overall operation of the electricity supply chain.

High-voltage transmission infrastructure tends to be much more networked than distribution systems. Networked infrastructure increases system resilience by enabling grid operators to reroute power flows when a single line or multi-line pathway is compromised. Transmission infrastructure already is significantly automated (through such tools as Automated Generator Control and advanced SCADA systems) and information intensive. New tools, such as highly granular system visualization solutions, synchrophasors, smart relays, and smart inverters increase network resilience. While changing weather patterns and storm intensity are impactful, the structure of most transmission networks is already hardened against such disruptive factors. What remains to be addressed more comprehensively is how transmission grids can resist cyber incursions that could paralyze wide areas of a large-scale interconnect, such as the Western or Eastern Interconnection. These considerations were discussed in the preceding section.

Stakeholder input as part of the QER process, FERC dockets, National Association of Regulatory Utility Commissioner meetings, and other venues have consistently raised the following issues concerning ISO/RTO wholesale markets:[147]

- The roles of mandatory capacity markets in PJM, ISO-New England, and parts of New York ISO
- The ability of bulk power markets, especially in RTO/ISO markets, to incentivize new generations in addition to natural gas and state renewable portfolio standard mandated renewables, thus helping with resource diversity, resource adequacy, and long-term decarbonization
- The incorporation of state policy and environmental goals in RTO/ISO markets
- The ability to integrate increasing wind and solar generation at lower costs, while allowing remaining traditional sources of generation to earn sufficient revenue to continue to provide needed generation and reliability services
- The ways to address the increasing changes occurring at the distribution level
- The continued evolution of transmission planning and seams issues between major bulk power market regions.

In addition to the issues noted above, analysis of markets with high volumes of VER, notably California, point to emerging impacts, which eventually will affect other regions as their VER increase as an overall share of the resource mix. It is in these emerging issues that new resilience and flexibility considerations come into focus. A 2014 study, "Investigating a Higher Renewables Portfolio Standard in California," which involved Los Angeles Department of Water and Power, Pacific Gas & Electric, Sacramento Municipal Utilities District, Southern California Edison Company, and San Diego Gas & Electric as sponsors. The study identified emerging operations and planning issues under a 50 percent renewable portfolio standard (note that California ISO already consistently handles up to 40 percent renewable resources on its system).[148] Concerns in the study included over-generation as a critical management challenge that occurs when "must-run" generation—non-dispatchable renewables, combined-heat-and-power, nuclear generation, run-of-river hydro, and thermal generation that is needed for grid stability—is greater than loads plus exports. The principal mitigation for over-generation in many current systems is curtailing renewable resource contributions to the overall resource mix. Future systems may increase the role of storage, DR, and flexibility to manage over-generation. Second, renewable resources can change supply patterns suddenly, and as the sun sets, significant solar production disappears, requiring a need for fast ramping generation to fill in for lost solar resources.

The study also found that a variety of integration solutions can reduce the cost of a high renewable scenario. Improvements in regional coordination—which address jurisdictional challenges when state regulation cannot reach beyond state borders, and Federal regulation cannot easily reach into distribution systems—could improve integration. DR, especially advanced practices that increase overall DR reliability, can support higher levels of VER integration. Energy storage is an important technology that must be developed and deployed as a key tool for VER impact mitigation. Finally, VER portfolio diversity is a key success factor as more VER volume impacts grids.

Resilience is an important transmission network matter, but its traditional treatment has occurred as part of ongoing, FERC-approved investments to meet NERC standards and to ensure reliable operations in regionally distinct conditions. The emergence of VER and their growing contributions to resource mixes in some U.S. regions bring with them a need to more robustly differentiate reliability investments from resilience investments. As noted, resilience in transmission networks with high VER requires behavioral changes in system operations, as noted above. In bulk power systems with wholesale market overlays, resolving valuation matters where curtailment of VER is a valid resilience methodology is a serious matter. To avoid complex issues of how to compensate curtailed VER adjustments in market designs and new market developments are required. For example, in California, one element in an overall VER management model is the Energy Imbalance Market created by California ISO, which involves PacifiCorp, a large multi-state utility based in the Pacific Northwest. These initiatives tend not to be considered resilience efforts when they are important contributors to both system reliability and longer-term resilience in high VER systems. In short, as resource mixes change with decarbonization efforts of grid operators and power producers, the role of resilience grows more important as a distinct complement to established reliability management investments and techniques.

The Role of Markets in Downstream Electricity Delivery Services

Presently, downstream electricity delivery services provided by the distribution function of electric utilities—whether integrated with retail customer service or separated into wires operations and competitive retail services—do not function with organized "retail commodity markets" that emulate upstream ISO/RTO wholesale markets. But, there are aspects of market mechanisms that impact grid operations and provide proxies for valuing various types of grid investments for reliability assurance, system flexibility, and network resilience. For example, some distribution systems allow net metering, which involves the sale of power from consumers to grid operators. Pricing of these services is based on state regulatory and ratemaking processes, not auction platforms like those used by ISOs/RTOs. Energy service providers, retail competitors, and aggregators compete through various sales channels for consumers interested in controlling and/or reducing energy costs, deploying onsite power generation, and adopting microgrids that optimize sources and uses of electricity as an integrated onsite system.

Downstream electricity markets may not yet value commodity electricity in a manner that allows for effective pass-through of wholesale clearing prices in real-time to end-use consumers. Wholesale and retail linkages may develop over time; the New York Reforming the Energy Vision process and consideration of distribution system operator models may provide meaningful guidance for such evolution. Whether realized or not, under appropriate and necessary requirements for visibility of such generation, downstream electricity delivery services achieve enhanced resilience by systematically promoting and integrating advanced DR and energy storage solutions into local grid operations.

Similar to wholesale markets and resilience considerations, distribution system resilience measures can be enhanced by incorporating behavioral systems and processes into specific asset-based investments that harden systems against severe weather-related impacts, physical threats, and cyber attacks.

Electricity Markets, Reliability, and Resilience

Reliability investments are typically incorporated into ratemaking processes for all electric utilities. Supplementary investments for recovery from outage events also are handled through established ratemaking processes. Resilience requirements tend to be valued as contributions to reliability and incorporated as part of ratemaking processes. These processes are more easily executed in structures that are traditional end-to-end, vertically integrated electricity delivery services; other market structures complicate reliability and resilience investment decision making. Short-run markets may not provide adequate price signals to ensure long-term investments in appropriately configured capacity. Also, resource valuations tend not to incorporate superordinate network and/or social values such as enhancing resilience into resource or wires into investment decision making. The increased importance of system resilience to overall grid reliability may require adjustments to market mechanisms that enable better valuation.

Grid Operations Planning and Resilience

Resilience of the electricity system is increasingly important. Recent weather extremes, climate change impacts, physical security and cybersecurity threats, and a changing workforce have added to the challenges faced by electric utilities, prompting industry to develop new multidisciplinary all-hazards approaches for managing these issues and making the grid more resilient.

Resilience Measures Expedited Restoration after Hurricane Matthew[aj]

Hurricane Matthew began impacting the southeast United States on Thursday, October 6, 2016, and the flooding caused by the storm continues to affect North Carolina and South Carolina. The initial effects of the storm were felt from Florida to Virginia, with increased rain and wind causing damage to energy infrastructure. Industry efforts to restore that damaged infrastructure are ongoing and have involved mutual assistance from utilities from across the country. More than 99 percent of customers who lost power had their power restored within 8 days, by 11:00 a.m., on October 14, 2016.

Florida Power and Light has invested $2 billion over the last 10 years, leveraging $200 million in Federal investment through the American Recovery and Reinvestment Act of 2009, to advance smart grid functionalities with technologies, such as advanced smart meters, distribution automation, and advanced monitoring equipment, for the utility's transmission system. Early damage assessments suggest that investments in resilience measures expedited Florida Power and Light's restoration timeline; without these new technologies and functions, it is estimated that restoration efforts would have taken 10–15 days. Florida Power and Light reports that 98 percent of the 1.2 million customers who lost power had their power restored within 3 days.

Government, industry, and the various state energy offices helped coordinate the national effort to restore power following the storm. Government responders helped industry crews access impacted areas, facilitated waivers requested by utilities to use unmanned aerial systems for damage assessments, and provided energy sector situational awareness reports that informed decisions about where to place limited Federal and state resources. Government responders remained in Georgia, as well as North Carolina and South Carolina, providing assistance until restoration was complete. The response effort built on lessons learned from Hurricane Sandy of 2012.

[aj] Department of Energy (DOE), "Final Hurricane Matthew Situation Report: October 14, 2016 12:00pm," DOE, October 14, 2016, 3, accessed January 4, 2017, http://energy.gov/sites/prod/files/2016/10/f33/2016_SitRep_12_Matthew_FINAL.pdf.

Resilience enhancement initiatives are generally focused on achieving at least one of three primary goals: (1) preventing or minimizing damage to help avoid or reduce adverse events; (2) expanding alternatives and enabling systems to continue operating despite damage; and/or (3) promoting a rapid return to normal operations when a disruption occurs (i.e., speed the rate of recovery). Resilience relates both to system improvements that prevent or reduce the impact of risks on reliability and to the ability of the system to recover more quickly.

Unlike reliability, there are no commonly used metrics for the resilience of the electric grid, and threats to system resilience are typically associated with disasters or high-intensity and low-frequency events. An additional complication is that the responsibility for maintaining and improving grid resilience lies with multiple entities and jurisdictions, including Federal and state agencies and regulatory bodies, as well as multiple utilities. For investments in electricity sector resilience, approval is generally up to the discretion of state public utilities commissions or equivalent bodies, which are balancing competing, more near-term interests. Furthermore, from the societal perspective, building resilience of critical infrastructure to future disasters involves decision making that also considers social, cultural, and environmental issues, which have both qualitative and quantitative value, from a risk assessment standpoint.[149] Therefore, building resilience to disasters depends upon close coordination among multiple entities, which have varying approaches to measuring electricity system performance and outcomes for society.

Perhaps most relevant is the underlying barrier to prioritizing investments in reliability and resilience that utilities and regulators face.[150] There is no established method for quantifying the benefits of investments, which depend on the occurrence of some events with low probabilities. One exception to this is an order recently released by the New York State Public Service Commission;[151] however, there is a clear need for a set of commonly used methods for estimating the costs and benefits of reliability and resilience investments.

Real-Time Electricity System Monitoring Enhances Situational Awareness

Maintaining situational awareness is an important aspect of overall resilience management in service to maintaining high electricity system reliability. Utilities rely on field personnel to assess and report grid system conditions through site inspections. During emergency situations, utilities' abilities to assess and communicate system status after a large disruption tend to be significantly degraded. Where there is a widespread disruption beyond electricity infrastructure damage, personnel may be responding to a specific emergency situation, which limits work scope. Transportation challenges, such as road blockages and traffic, may also prevent the movement of utility personnel and equipment to assess electricity infrastructure throughout the affected area. Furthermore, wide communication system outages will also limit utilities' ability to assess system conditions. These initial assessment limitations then impede response and recovery planning.[152]

When distribution-level SCADA pairs with a distribution management system, operations can be conducted remotely, increasing the speed at which a utility can identify and locate faults on the distribution system and restore service, as well as manage voltage and reactive power to reduce energy losses and integrate distributed generation and storage technologies.[153]

Analyses of the August 2003 Northeast blackout concluded that it was preventable and that the reliability of the U.S. and Canadian power systems needed an immediate and sustained focus on investments in technologies to promote "situational awareness" and adequate responses to major disturbances.[154] New institutional structures and processes were developed to coordinate information among power pools for improved coordination across systems and across NERC regions for improved coordination of system resource adequacy requirements.

Grid Operations and Communications Redundancy

With the increasing interdependence between communications and electricity, redundancy in communications systems is essential to continuity of grid operations. Some utilities have expanded satellite communications capabilities with mobile satellite trailers that can be deployed to field staging areas and include full capabilities for email, Internet, outage management systems, voice-over Internet protocol telephones, and portable and fixed satellite phones. Others have redundant and diversely routed dedicated fiber-optic lines to enable continued operations.[155, 156]

Dynamic Line Rating Systems for Transmission Systems

Current transmission system operations rely on fixed ratings of transmission line capacity that are established to maintain reliability during worst-case conditions (e.g., hot weather). Line ratings may also be reduced if ambient conditions are abnormally hot and still. There are times when the conditions associated with establishing line ratings are not constraining, and transmission lines could be operated at higher usage levels. Dynamic line rating systems help operators identify available real-time capacity and increase line transmission capacity by 10 to 15 percent. Dynamic line rating systems can help facilitate the integration of wind generation into the transmission system.[157] This real-time information about overhead conductors can help further enhance situational awareness, while simultaneously providing economic benefits. Incremental investments that increase the capacity of the existing transmission system can provide a low-cost hedge, as well as enhanced real-time awareness. However, economic, financial, regulatory, and institutional barriers limit incentives for regulated entities to deploy these low-capital cost technologies that could increase transmission capacity utilization.[158] NERC has an important role to play in setting relevant standards, which would drive increased operational focus on dynamic line ratings as part of overall response and recovery planning and execution.

Information Collection and Sharing Can Mitigate Threats to the Grid

The Federal Government has established programs and launched pilots to analyze cyber and physical threat information, share information with industry, and provide technical assistance to state and utility decision makers in their mitigation efforts. The electric sector utilizes resources and participates in these programs, while also collaborating with one another through industry-led initiatives.[ak] While several Federal programs facilitate the sharing of threat information with industry, challenges remain with respect to the Federal Government's ability to provide data quickly enough to be useful. Several factors limit timely and effective exchange of information, including human delays in sharing information, procedural barriers related to classified information, and liability and privacy concerns from industry.

One particular challenge is that some government intelligence on threat indicators and vulnerabilities is classified, preventing power sector owners and operators who lack the appropriate security clearances from accessing relevant information. Many sector owners and operators and Federal employees often lack the security clearances to access this information.

Another important information gap is a national repository for all-hazard event and loss data, which would help utility regulators, planners, and communities analyze and prioritize resilience investments. In 2012, the National Academy of Sciences recommended the establishment of such a database[159] to support efforts to develop more quantitative risk models and better understand structural and social vulnerability to disasters.

The Grid and Emergency Response

As not all hazards to the grid can be prevented, local authorities and stakeholders focus on failing elegantly and recovering quickly. Response options can leverage existing capabilities, tools, and equipment to act immediately before, during, and after a disruptive event. Public and private sectors can provide emergency response resources, which can include mobile incident management and command centers, mutual aid agreements, and access to specialized materials.[160]

A utility's power restoration and business continuity planning includes year-round preparation for all types of emergencies, including storms and other weather-related events, fires, earthquakes, and other hazards, as well as cyber and physical infrastructure attacks. A speedy restoration process requires significant logistical expertise, skilled/trained certified workers, and specialized equipment. Utility restoration workers involved in mutual assistance typically travel many miles from different geographic areas to help the requesting utility to rebuild power lines, replace poles, and restore power to customers.[161]

[ak] For example, in 2011, Edison Electric Institute, in conjunction with private-sector experts and its member utilities, initiated the Threat Scenario Project to identify threats and practices to mitigate these threats. Identified threats included coordinated cyber attacks, as well as blended physical and cyber attacks. The project established common elements for each threat scenario, including likely targets, potential threat actors, specific attack paths, and the likely impacts of a successful attack. Edison Electric Institute, "EEI Business Continuity Conference Threat Scenario Project (TSP)" (presented on April 4, 2012), 1, http://www.eei.org/meetings/Meeting_Documents/2012Apr-BusinessContinuity-Treat%20Scenario%20Project_Engels.pdf.

Lessons Learned from Severe Outages[al, am, an]

After the immediate response to manage the adverse effects of an event, recovery activities and programs take place to effectively and efficiently return operating conditions to an acceptable level. This may entail restoring service to the same level as before the event or stabilizing service to a new normal. Recovery measures usually consist of longer-term remediation measures and include access to critical equipment, mutual aid agreements with other utilities, and after-action reporting that would make the grid more resilient to future disruptions.

Hurricane Sandy (and Katrina in 2005) caused significant damage to critical national energy infrastructure and stressed Federal capabilities to protect and restore critical infrastructure. In the aftermath, the White House and Federal Emergency Management Agency (FEMA) conducted detailed analyses of the Federal response to identify challenges and lessons learned and to make recommendations for future disaster preparedness and response efforts. Several common themes emerged about response and recovery:

Ensure mutual aid in the utility sector. In response to Hurricane Sandy, electric utilities mobilized the largest-ever dispatch of mutual aid workers (totaling approximately 70,000), primarily from the private sector but including some government workers.

Grant energy sector restoration crews the appropriate credentials to enter damaged work zones and have priority for fuel distribution. In the storm response, some energy sector repair crews were designated as first responders, giving them priority access to fuel and expediting travel into affected areas. However, not all energy infrastructure repair crews had this status or access. After Hurricane Sandy, the Department of Energy's (DOE's) Office of Electricity Delivery and Energy Reliability recommended that electrical workers, as well as refinery and terminal repair crews, be given appropriate credentials to enter damaged work zones quickly.

Coordinate Emergency Support Function (ESF) 12 functions across Federal agencies. ESF-12, under the National Response Framework, is an integral part of the larger DOE responsibility of maintaining continuous and reliable energy supplies for the Nation through preventive measures and restoration and recovery actions in coordination with other Federal Government and industry partners. In the "Hurricane Sandy FEMA After-Action Report," FEMA noted that ESF-12—coordinated by DOE—struggled to fully engage supporting Federal departments and energy sector partners in addressing energy-restoration challenges. A DOE report on the response to Sandy recommended that DOE permanently deploy DOE/ESF-12 responders to the states and regions so they could provide on-the-ground situational awareness of energy disruptions, establish relationships with State and local energy sector partners, and gain first-hand system knowledge to better coordinate energy preparedness efforts with state and local public and private sector partners.

[al] White House, *The Federal Response to Hurricane Katrina: Lessons Learned* (Washington, DC: White House, February 2006), 135, https://georgewbush-whitehouse.archives.gov/reports/katrina-lessons-learned/.

[am] Federal Emergency Management Agency (FEMA), *Hurricane Sandy FEMA After-Action Report* (FEMA, 2013), 10, https://www.fema.gov/media-library-data/20130726-1923-25045-7442/sandy_fema_aar.pdf.

[an] Department of Energy (DOE), *Overview of Response to Hurricane Sandy-Nor'Easter and Recommendations for Improvement* (Washington, DC: DOE, February 2013), 12, http://energy.gov/sites/prod/files/2013/05/f0/DOE_Overview_Response-Sandy-Noreaster_Final.pdf.

State governments play a major role in coordinating and directing response and recovery efforts to electricity disruptions. These responsibilities received a boost through DOE grants to states and local governments to support a State Energy Assurance Planning Initiative. Grants were awarded under this initiative in 2009 and 2010 to 47 states, the District of Columbia, 2 territories, and 43 cities.[162] The grants were used over a 3–4-year period to improve energy emergency preparedness plans and to enable quick recovery and restoration from any energy supply disruption. States also used these funds to address energy supply disruption risks and vulnerabilities, with the aim of mitigating the devastating impacts that such incidents can have on the economy and on public health and safety.[163]

Each state under the Energy Assurance Planning Initiative was required to track energy emergencies, to assess the restoration and recovery times of any supply disruptions, to train appropriate personnel on energy infrastructure and supply systems, and to participate in state and regional energy emergency exercises that were used to evaluate the effectiveness of their energy assurance plans. States were also required to address cybersecurity concerns and to prepare for the challenges of integrating smart grid technologies and renewable energy sources into their plans. Because of the initiative, nearly all state and territory governments and select local governments have Energy Assurance Plans in place. A review of the State Energy Assurance Plan was recommended to occur every 2 to 3 years, and to date some states have undertaken update efforts.[164]

Backup Power and Spare Transformers for Emergency Response

During outages and emergencies, fast but safe system recovery is the mission of a utility. Part of the effort to maintain service while power is being restored involves the use of backup power along with speedy deployment of equipment spares that may have failed.

Backup power sources can be used to bypass existing distribution service lines until they are restored, and they are used by customers in lieu of utility service. Critical facilities, such as hospitals, maintain robust backup power systems. Microgrids offer islanding solutions for large facilities and campuses by their integration of DG, storage, and demand side management solutions. According to an Argonne National Laboratory report, "One hundred percent of the following assessed facility groups have an alternate or back [-up] power in place: Banking and Finance; Critical Access Hospitals; Private or Private Not-for-Profit General Medical and Surgical Hospitals; State, Local, or Tribal General Medical and Surgical Hospitals."[165] More than 75 percent of other users, including manufacturing, wastewater, hotels, arenas, retailers, offices, and law enforcement offices, also maintain some form of alternate or backup power source.[166] Critical data centers and server centers also have robust backup systems that enable islanding from the impacts of grid failures.

It is also important to ensure that key grid components are available in the event of emergencies. Utilities have robust supply chains and inventory management systems that help ensure that spare transformers, including the stocking of interchangeable spare transformers,[167] the ordering of conventional spares in advance, and the early retirement of conventional transformers for use as spares. Conventional spares are typically used for planned replacements or individual unit failures; but these transformer spares can also be used as emergency spares. Under this approach, the spares are identical to those transformers that are to be replaced and often stored at the substation next to existing transformers—which allows for quick energization without the transformer being moved. The close proximity of such spares to the existing transformers can lead to potential high-intensity and low-frequency physical attacks or weather events. Some utilities retain retired transformers to repurpose them as emergency spares.[168] These are transformers that have retired but not failed, which would allow their use as temporary spares until a new transformer is manufactured and transported.[169] Utilities also use mobile transformers and substations to temporarily replace damaged assets, much in the way that mobile power is used for resilience and repowering efforts.

Nuclear Regulatory Commission Requirements

The Nuclear Regulatory Commission has issued several cyber and physical security regulations for nuclear power plants covering cybersecurity plans, response and recovery strategies from aircraft crashes, and training for security personnel, among other measures. For example, Title 10 of the Code of Federal Regulations, Section 73.54 stipulates that licensees provide "…high assurance that digital computer and communication systems and networks are adequately protected against cyber-attacks…" Each nuclear power plant must submit a cybersecurity plan and implementation schedule, which is then reviewed by the Nuclear Regulatory Commission.[ao] Additionally, the Nuclear Regulatory Commission is also required to conduct "force-on-force" exercises at nuclear power plants at least once every three years. These security exercises deploy a mock adversary force attempting to penetrate a plant's critical locations and simulate damage to target safety components. These exercises provide an evaluation of power plant security and identify deficiencies in security strategy, plans, or implementation. When these deficiencies are identified, additional security measures must be promptly implemented.[ap] These regulations have led to significant investments by nuclear power plant operators.

[ao] Mark Holt and Anthony Andrews, *Nuclear Power Plant Security and Vulnerabilities* (Washington, DC: Congressional Research Service, January 2014), 11, https://fas.org/sgp/crs/homesec/RL34331.pdf.

[ap] "Frequently Asked Questions About Force-on-Force Security Exercises at Nuclear Power Plants," Nuclear Regulatory Commission, accessed August 1, 2016, http://www.nrc.gov/security/faq-force-on-force.html.

Some utilities retain retired transformers to repurpose them as emergency spares. These are transformers that have retired but not failed, which would allow them to be used as temporary spares until a new transformer is manufactured and transported.[170] Utilities also use mobile transformers and substations to temporarily replace damaged assets. "A mobile substation includes a trailer, switchgear, breakers, emergency power supply, and a transformer with enhanced cooling capability. These units enable the temporary restoration of grid service while circumventing damaged substation equipment, allowing time to repair grid components. Mobile transformers are capable of restoring substation operations in some cases within 12–24 hours."[171]

Finally, utilities preparing for response after cyber disruptions are also taking measures to build redundancies for cyber infrastructure. Some of these measures include building backup control centers for full functionality and developing independent, secured control mechanisms that would provide limited vital functions during an emergency.[172] NERC CIP standards require utilities to maintain backup energy management systems to manage bulk electric system generation and transmission assets.[173]

Equipment Constraints on Speedy Restoration: Large Power Transformers

The shortage of critical electrical equipment can cause significant delays for power restoration. Specifically, the loss of multiple large power transformers (LPTs) may overwhelm the system and cause widespread power outages, possibly in more than one region, increasing vulnerability and the potential for cascading failures.

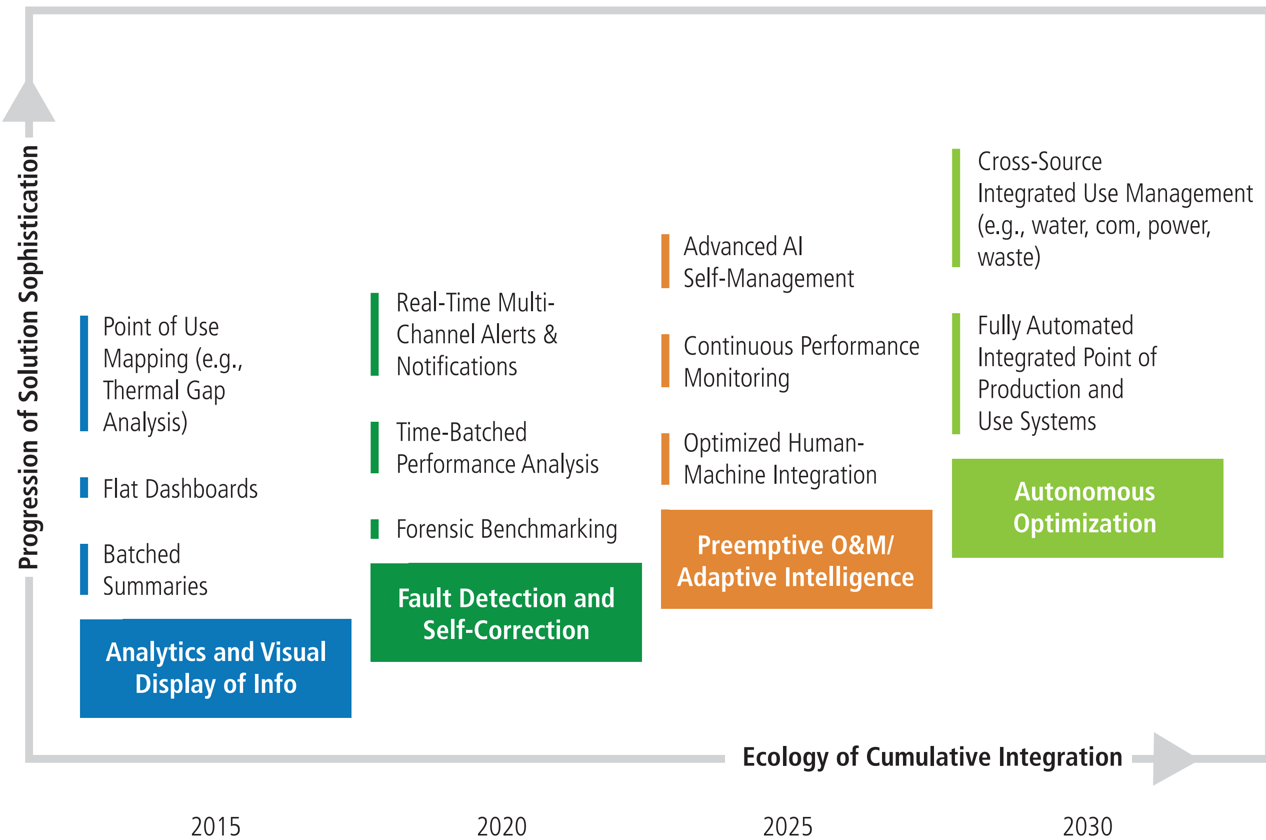
Replacement of multiple, failed LPTs is a challenge, due to the cost and complex and lengthy process involving the procurement, design, manufacturing, and transportation of this equipment. These processes can take months, depending on the size and specifications of the needed LPTs, even under an accelerated schedule and normal transportation conditions. Utilities mitigate the risk of losing LPTs through several strategies, including adopting measures to prevent or minimize damage to equipment, purchasing and maintaining spare transformers (conventional spares), identifying a less critical transformer on their system that could be used as a temporary replacement (provisional replacement transformer), and/or setting up contracts to procure a transformer through a mutual assistance agreement or participation in an industry sharing program.

There are currently three key industry-led, transformer-sharing programs in the United States—NERC's Spare Equipment Database program, Edison Electric Institute's Spare Transformer Equipment Program, and SpareConnect. Another program, Recovery Transformer, developed a rapidly deployable prototype transformer designed to replace the most common high-voltage transformers, which DHS successfully funded in partnership with Electric Power Research Institute and completed in 2014.[174] As of December 2016, three additional programs—Grid Assurance, Wattstock, and Regional Equipment Sharing for Transmission Outage Restoration (commonly referred to as RESTORE)—are in development. QER 1.1 recommendations noted that DOE should "analyze the policies, technical specifications, and logistical and program structures needed to mitigate the risks associated with the loss of transformers."[175] In December 2015, Congress directed DOE to develop a plan to establish a strategic transformer reserve in consultation with various industry stakeholders in the FAST Act. To assess plan options, DOE commissioned Oak Ridge National Laboratory to perform a technical analysis that would provide data necessary to evaluate the need for and feasibility of a strategic transformer reserve. The objective of the study was to determine if, after a severe event, extensive damage to LPTs and lack of adequate replacement LPTs would render the grid dysfunctional for an extended period (several months to years) until replacement LPTs could be manufactured. DOE's recommendations will be published in the report to Congress in early 2017.

Grid Analytics and Resilience

Both grid reliability and resilience increasingly depend on highly granular data about what is happening on grids in real time. Data analysis is an important aspect of today's grid management, but the granularity, speed, and sophistication of operator analytics must increase as greater distribution system complexity occurs. Regional differences may matter, but the core analytic engines that must be developed and configured for grid operator use will be the same across regions and systems.

Figure 4-13. Information Drives Solution Sophistication, Which Drives New Benefit Realization for Grids[176]



Grid information systems are expected to evolve over time, growing increasingly autonomous and self-managing. Increased autonomy and self-management also involves increased system integration, which amplifies the complexity of systems and requires a degree of human-machine interdependence that is unprecedented for grid operations. Acronym: operations and maintenance (O&M).

Smart Grid and System Resilience

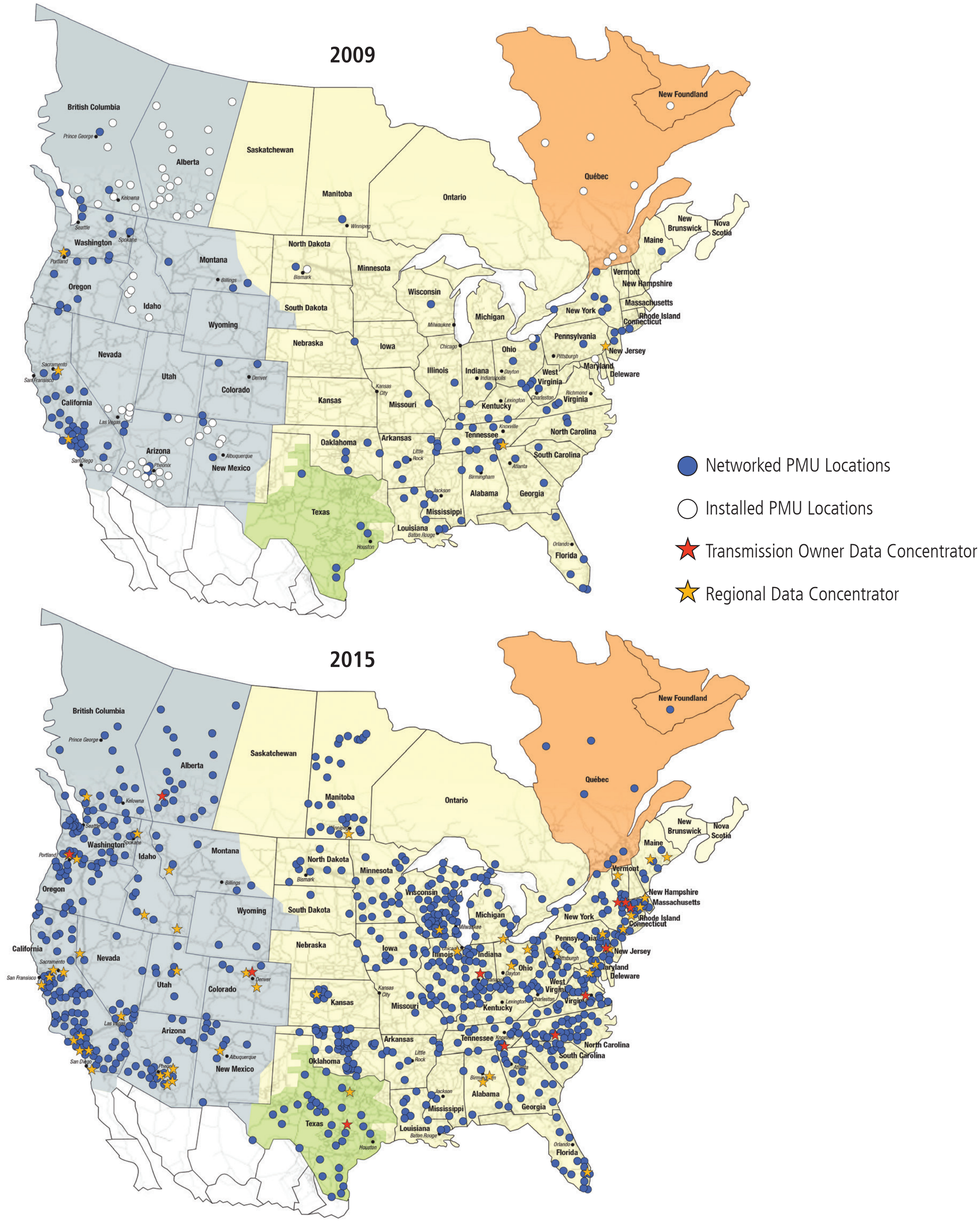
The installment and implementation of advanced meters and smart grid technology can make significant contributions to system resilience. Advanced smart grid systems can be used to expedite information flow; remotely monitor demand, performance, and quality of service; enhance system efficiency; and improve outage detection and restoration by identifying the location and description of damaged equipment. Real-time system monitoring can support hourly pricing and reactive power and/or DR programs, which allow utilities to make same-day operational decisions, near-term forecasts, and scenario evaluations. Historical data, coupled with predictive modeling of extreme weather events and the related effects on electric infrastructure, can also be used to inform management decisions, identify areas of greatest risk, ascertain system vulnerabilities, allocate resources, and help prioritize investments.

Still, system managers need better real-time information about system trends and changes, including the growth in VER, the rise of the "prosumer," two-way electricity and information flows, and real-time load management data—which means that demands on and expectations of SCADA systems are only increasing. Grid modernization requires changes in operational systems and processes, and in the way that system planners design for grid evolution. Critical to smart grid realization is systems engineering to determine the requirements for ICT infrastructure, which includes how latency factors (communications delays) and bandwidth requirements are embedded in operations to accommodate the proliferation of intelligent assets from relays to whole substations to automated customer DR controls that grid operators can access and use.

Fortunately, as the complexity of the electricity system increases, so do computer- and network-based capabilities. The growing electricity-ICT interdependence is enabled in part by new technologies, such as sensors and software that can provide greater situational awareness of grid conditions and operational efficiencies (although much more work is needed).[177] Large volumes of data are, however, unwieldy, and developing additional ways to translate data into usable and timely information is essential. Networks are evolving to include cloud computing and IoT technologies to help reduce costs, increase efficiencies, and increase system integration.[178, 179] Smart meters, synchrophasors, and other devices have also been deployed across the grid. Even electromechanical devices, like voltage regulators, are adopting digital control interfaces.

On transmission networks, SCADA systems traditionally have been used to monitor and control power systems by measuring grid conditions every 2 to 4 seconds. Synchrophasor technology, which addresses the lack of situational awareness provided by conventional instrumentation, uses high-resolution phasor measurement units (PMUs) that provide time-synchronized data at a rate of more than 30 times per second to detect destabilizing network oscillations that would otherwise be undetectable. Strategically located PMUs connected by high-speed communications networks provide grid operators with wide-area visibility to better detect system disturbances, improve the grid's efficiency, and prevent or more quickly recover from outages. In 2009, there were 166 PMUs in the United States—there are now over 1,700 PMUs located around the country (Figure 4-14).[180] The impact of this deployment is that it now takes 16 milliseconds for PMUs in the Western Interconnect to send signals over a dedicated fiber-optic system to transmission operators in control centers throughout the system—a system that covers western North America from Mexico to western Canada, from east of the Rockies to the Pacific Ocean.

Figure 4-14. Phasor Measurement Units, Technologies That Enable Superfast Network Management across Large Interconnected Systems, Are Being Deployed to Improve Grid Operations.[181]



Note the concentration of phasor measurement units (PMUs) in regions and interconnected systems where ISOs and RTOs dominate transmission service. PMU deployment can be interpreted as a first mover in the development of smart grids and as evidence that upstream transmission systems are advancing more consistently and at a faster pace toward smart grid realization than local distribution systems, although recent rate cases and public utility budgets for larger investor-owned utilities and public power indicate that smart grid investments are beginning to ramp up quickly. However, it should not be assumed that PMU deployment at the distribution level will mirror that at the transmission level because distribution smart grid deployment is much more complex in scale and scope. Note that the Western Interconnect is in gray.

The electricity sector has also been relying on a variety of redundant communications networks for operations since its inception. Internet Protocol-based communications (networking) systems—whether fiber-optic, radio, or other means for conveying data—can be owned by utilities or provided by telecommunication firms. Utilities have invested heavily in these ICT networks over the last decade, in part spurred by funding Congress provided through ARRA. Roughly one-third of customers are connected to the distribution grid by the 60 million smart meters that serve as an essential building block to grid digitization.[182, 183] Smart meters send data to utility control systems every 15–60 minutes through communications networks and can provide information back to customers in real time, often through the Internet. These meters enable remote meter reading, connections, and disconnections, and they allow for improved outage management and restoration. During Superstorm Sandy, smart meters reduced PECO Energy's restoration time by 2–3 days. Florida Power and Light has developed a tablet-based application for its field crews using AMI and geographic information systems data to improve emergency response; this was recently used to increase the speed of power recovery after Hurricane Matthew. Smart meters have an additional benefit—they give customers price information that enables them to respond to market conditions and reduce their electricity bills.

States and RTOs/ISOs will continue in their traditional regulatory roles as the system evolves. Given the increasing technical sophistication of grid operations, state regulatory staff may need additional support from the Federal Government in evaluating technical proposals from utilities as they seek to modernize their grids. Of concern are grid security standards across distribution delivery services. Proactive planning should be considered, as well as emergency response. The impetus to invest in mitigation and preparedness may only occur following a catastrophe, but proactive investments can prevent catastrophe and ultimately benefit ratepayers in the long term. However, distribution utilities face various challenges to implementing cybersecurity measures, including outdated legacy equipment, budgetary constraints, workforce readiness, and technology availability. Recent electricity response exercises demonstrate the nascent status of coordinated industry and government efforts to jointly respond to potential cyber incidents. The electricity industry has a long history of employing mutual assistance agreements to recover from most disruptions, and the Nation would benefit from the development of appropriate mechanisms for addressing cybersecurity disruptions.

Underinvestment in Research, Development, Demonstration, and Deployment, and Implications for System Resilience

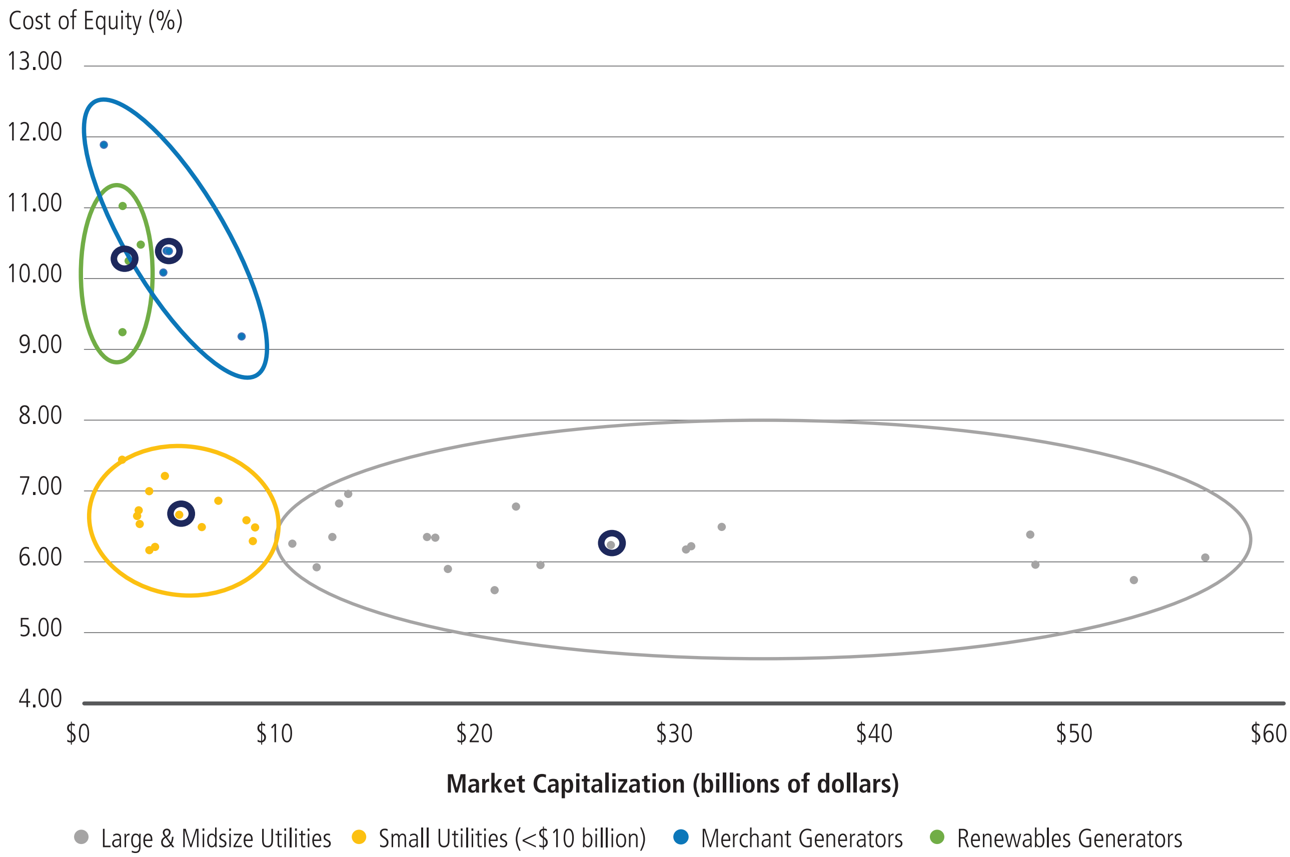
This chapter has emphasized the importance of resilience to overall grid reliability. From an investment perspective, high grid reliability is a key factor in the treatment by investors of utilities (both public and private) as low-risk investments with predictable returns. Analysis suggests that in an increasingly complex grid management environment, more focused investments are needed to ensure continued high system reliability and resilience. Future investments must focus on innovations that help mitigate new sources of system disruption, including VER, extreme weather, and physical and cyber attacks; these investments must occur in an environment that does not necessarily favor increased utility funds being used for research, development, demonstration, and deployment (RDD&D).

Despite existing RDD&D funding and activity in the electricity sector, there is systemic underinvestment in RDD&D of technologies, as described in Chapter III (*Building a Clean Electricity Future*). Also, private industry serving the electricity sector lacks incentives for investments in infrastructure resilience, in part, due to uncertainties in emerging risks.[184] Utilities acquiring resilience assets and solutions face rate proceedings that have an inherently conservative perspective on new technologies and approaches, which limits the ability to test new approaches in a timely manner and move to deploy successful efforts at an accelerated pace compared to traditional electricity sector norms. The lack of incentives, and preference for existing methods, constrains the innovation options that are pursued and tested, then enter the innovation process supply chain. These characteristics drive the need for additional Federal RDD&D opportunities to improve the resilience of electricity systems, as well as system security, rapid response, and recovery from disruptions.

Entities that operate distribution systems—the grid components most critical to reliability, security, and resilience—operate almost universally on a cost-of-service basis. The combination of stable revenues and low operational risk enables these entities—investor-owned utilities, Munis, Coops, and other entities—to acquire capital at lower rates (Figure 4-15). Investors view these entities as relatively low-risk investments compared with other electricity sector opportunities that face more competitive pressures.

As the operational characteristics of the industry evolve, traditional utility returns may not be compelling for investors, if sector transformations cause utilities to take on more or different types of risks. New types of regulatory structures may be needed to provide appropriate incentives to plan for an increasingly uncertain and more complex risk environment, as well as incorporate new approaches and technologies, which enable the kind of resilience investments that may be needed but not otherwise funded.

Figure 4-15. Cost of Equity by Company Type and Size for Sampled Power Sector Companies[185]



Regulated utilities, with their predictable revenues and low risks, tend to be viewed as safe investments, exhibiting a low cost of equity compared to the rest of the sector. As the industry addresses increasing risks and uncertainties, existing regulatory structures may evolve to meet risk appetite.

Planning Is Essential for System Reliability and Resilience

The responsibility for maintaining and improving grid reliability and resilience resides with a complex mix of entities with overlapping and sometimes inadequate jurisdictional responsibilities, which include Federal and state agencies and regulatory bodies, regional and national reliability organizations, and multiple utilities with various business models.

There are many existing planning platforms for reliability planning that are well understood by utilities, stakeholders, and other responsible entities. New, value-added planning contributions can help grid operators make tradeoffs among multiple investment options, strengthen the system, and help ensure resilience and reliability, which are needed for transforming a dramatically changing electricity system. Rigorous tradeoff analysis implies and includes rigorous risk analysis. Planning elements that should be added to existing platforms to accommodate system changes, challenges, threats, and opportunities include the following:

- Regional integrated resource planning that includes both T&D
- Integration of end-to-end options for optimal resource mix and operational integrity into existing planning
- Analyses with proposals for how to mitigate vulnerabilities.

In many parts of the country, investor-owned utilities conduct integrated resource planning in accordance with state requirements that were established through legislation or regulatory actions. While more than half of states in the Nation have integrated resource planning requirements, other states have adopted "Long-Term Procurement Planning" or other similar processes.[186, 187] Only a small number of distribution utilities conduct planning[188] in response to state policies,[189] aiming to increase resilience to extreme weather events or stressful system conditions. Also, with few exceptions, very few utilities take emerging threats from climate[190, 191] or cyber attacks into consideration when conducting integrated resource planning and distribution planning.[192]

In most cases, cybersecurity efforts are often funded out of the overall rate base. This means that funding for cybersecurity comes at the expense of profit or other investment needs, which may have a disproportionate budgetary impact on smaller distribution utilities. In rarer cases, distribution utilities have a separate security recovery factor in their rate structure.

Integrated Planning Considerations

The changing role of the consumer that drives the transformation of distribution also drives a need for new distribution planning approaches and tools to effectively integrate DER into the grid and to understand the benefits and costs for developing forward-looking investment plans. New solutions like smart inverters bring important issues to center stage, like whether such solutions can be fully valued prior to deployment. Because consumer preferences and needs are changing faster than the pace of grid planning, there may be misalignment of operating circumstances. Whatever investments are planned are likely to require revisions as actual events diverge from said plans. Continued and rapid changes on the customer side of the meter may require adjustments in regulatory processes to assist grid owners and operators in keeping systems up to date.

Methods are under development in leading states (e.g., California and New York) to incorporate DER and the growing role of "prosumers"—consumers that produce power for the grid—and third parties into the distribution system planning processes. Important considerations for the development of such methods should include hosting capacity of distribution feeders for DER and probabilistic DER growth scenarios, as well as balance utility investments in system upgrades versus the services provided by DER (e.g., in energy supply, supply/load balancing, storage, and support of both frequency and voltage regulation). These planning processes will need sufficient transparency to permit all stakeholders, including DER service providers, to participate in supporting long-term capacity and energy requirements. Contractual provisions between utilities and DER service providers will need to be established to ensure grid reliability and security, which might benefit from the development of standard offer DER contracts. As capacity and energy are increasingly being delivered at the distribution system level, distribution- and transmission-level planning will need to be integrated.

Integrated Probabilistic Planning as an Emerging Tool

Typically, reliability decisions are based on a deterministic, binary decision—a new facility is approved if it resolves a violation of a reliability standard. In contrast, economic decisions are based on a scenario framework, where the expected value of a facility is evaluated across a range of likely scenarios. The changing system topology, uncertain regulatory frameworks, decentralized market decisions, and evolving vulnerabilities introduce economic and reliability uncertainties and risks that cannot be adequately assessed through a deterministic framework.

Probabilistic risk assessment (PRA) methodologies offer a framework to consider underlying uncertainties and risks. PRA methods in transmission planning are still at a research stage and are not implemented widely. Currently, PRA is used to model topological changes, such as variations in renewable generation levels; variations in load level due to weather and DER output; generation and transmission equipment performance; variations in hydro-generation; and physical threats like weather.[193] However, considerable barriers to implementation of PRA approaches in transmission planning include the following:

Tradition of planning for worst-case scenarios using a deterministic approach

- Lack of industry-wide accepted approach for reliability indices in PRA framework
- Lack of standardization and availability of historic reliability data
- Lack of qualified workforce, skillset, and awareness of PRA approaches
- Lack of modeling tools for implementing PRA methodologies
- Lack of commercial tools for system security assessment under PRA framework.[194]

The Grid of the 21st Century

The electricity sector's long history is one of managing continuous, albeit slow, change while sustaining the same high reliability year in and year out. The stock of the sector is incrementally refreshed as needed, but changes highlighted in this chapter and other chapters of QER 1.2 call attention to several factors that place new emphasis on the sector's effort to sustain high reliability, security, and resilience.

A transformed 21st-century grid is likely to be one that invests more in flexibility and resilience to achieve the same desired outcome that is the prime directive of grid operators—sustained, high-service reliability. How the grid is managed depends on the capabilities built into the stock of assets that make up the end-to-end supply chain, but managing real-time operational flows also requires specific systems and processes to continuously succeed. The complexity of grid operations requires grid control tools that enable granular visibility and certain operational algorithms that help grid operators stay on top of second-to-second and millisecond-to-millisecond changes. The era of enhanced grid operations through artificial intelligence is here. Execution, however, must occur in a context that assiduously assures deflection of cyber attacks that could cripple grids; it must also occur through market mechanisms to help value and ensure cost-effective outcomes.

State and Federal regulatory bodies and policymakers play key roles in helping ensure system integrity, safety, and the ongoing financing of the electricity sector. Planning, which is central to ensuring long-term stock and flow integrity, must evolve as the sector itself evolves. More robust modeling, improved risk analysis, and better optimization realization at the two-way interface of information and energy flows between consumers and grid operators are important improvements that are likely to be significant contributors to enabling a transformation that ensure today's service reliability and quality can continue, if not improve.

This is the state of sector grid management as the Nation continues its march deeper into the 21st century. The scope of transformation required to adapt to new security concerns, coupled with the organic evolution of a sector that is qualitatively changing as consumers have more direct and indirect influence on grid reliability, are non-trivial costs that must be financed and paid for. There are many ways to facilitate transformation and assist grid operators and other stakeholders in the sector in adapting to the sector's changing physical and cyber "topography." The recommendations based on the analysis in this chapter are covered in Chapter VII (*A 21st-Century Electricity System: Conclusions and Recommendations*).

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Chapter V

ELECTRICITY WORKFORCE OF THE 21ST CENTURY: CHANGING NEEDS AND NEW OPPORTUNITIES

This chapter provides an overview of the composition of the electricity industry workforce, as well as the challenges the sector faces in maintaining an adequate and skilled workforce for the 21st-century electricity system. This chapter further examines how qualities and characteristics of the electricity workforce are shifting in light of the ongoing transformation of the energy sector, and it provides an overview of how industry and government action can respond to challenges facing the industry.

FINDINGS IN BRIEF:
Electricity Workforce of the 21st Century: Changing Needs and New Opportunities

- Over 1.9 million people are employed in jobs related to electric power generation and fuels, while 2.2 million people are working in industries directly or partially related to energy efficiency.
- Job growth in renewable energy is particularly strong. Employment in the solar industry has grown over 20 percent annually from 2013 to 2015. From 2010 to 2015, the solar industry created 115,000 new jobs. In 2016, approximately 374,000 individuals worked, in whole or in part, for solar firms, with more than 260,000 of those employees spending most of their time on solar. There were an additional 102,000 workers employed at wind firms across the Nation. The solar workforce increased by 25 percent in 2016, while wind employment increased by 32 percent.
- The oil and natural gas industry experienced a large net increase in jobs over the last several years, adding 80,000 jobs from 2004 to 2014. Unlike coal production, natural gas production is projected to increase over the coming decades under a business-as-usual scenario, sustaining natural gas industry employment.
- Employment in the natural gas extraction industry is regionally and temporally volatile; 28,000 jobs were lost between January 2015 and August 2016. Shifts in locations pose challenges for employees and the economies of the areas where they live and work.
- Between 1985 and 2001, coal production increased 28 percent as industry employment fell by 59 percent due to efficiencies gained by shifting production from Appalachia to the West.
- Aside from a minor employment increase from 2000 to 2011, 141,500 domestic coal jobs were lost between 1985 and 2016, and the industry shrank by 60 percent. In 2015, annual coal production was at its lowest level since 1986, and it is forecast to continue declining over the coming decades. As of November 2016, according to data from the Bureau of Labor Statistics, the coal mining industry employs about 53,000 people.
- Despite ongoing economic challenges in the Appalachian region, the non-highway appropriated budget for the Appalachian Regional Commission (ARC), a federally funded regional economic development agency, has fallen from roughly $600 million in the early 1970s to around $100 million in the 1980s and remained roughly constant until 2016. The ARC budget recently increased from $90 million in fiscal year 2015 to nearly $150 million in fiscal year 2016.
- The Abandoned Mine Lands Reclamation Fund's (AML Fund's) inability to fully support the reclamation of lands disrupted by the coal mining industry has the potential to leave communities in regions with declining local revenues with polluted and unsafe lands and few means to repair the damage. The AML Fund's increased ability to support coal mine reclamation would provide local employment opportunities and help coal communities transition to new industries.
- The continued fiscal difficulties of coal miner pensions threaten the solvency of the Pension Benefit Guaranty Corporation, a Federal agency that insures private-sector pension funds and is funded out of insurance premiums paid by member funds.

FINDINGS IN BRIEF:
Electricity Workforce of the 21st Century: Changing Needs and New Opportunities (continued)

- Proliferation of information and communications technologies and new technologies like distributed generation, smart home devices, and electric battery storage have led to new businesses and employment opportunities, which will require a wide array of new skills.
- The electricity industry will need a cross-disciplinary power grid workforce that can comprehend, design, and mange cyber-physical systems; the industry will increasingly require a workforce adept in risk assessment, behavioral science, and familiarity with cyber hygiene.
- A dip in the number of electricity industry workforce training programs in the 1980s contributed to a currently low number of workers in the electric utilities able to move into middle and upper management positions—creating a workforce gap as the large number of baby boomers retire.
- Workforce retirements are a pressing challenge. Industry hiring managers often report that lack of candidate training, experience, or technical skills are major reasons why replacement personnel can be challenging to find—especially in electric power generation.
- Electricity and related industries employ fewer women and minorities than the national average, but have a higher proportion of veterans. Only 5 percent of the boards of utilities in the United States in 2015 included women, and approximately 13 percent of board members among the top 10 publicly owned utilities were African American or Latino. Underrepresentation in or lack of access to science, technology, engineering, and mathematics educational opportunities and programs contribute to the underrepresentation of minorities and women within the electricity industry.
- From 1995 to 2013, the number of injuries per 100 employee-years in the electricity utility industry decreased from 4.7 to 1.3. However, line workers continue to experience hazardous working conditions. In 2014, electrical power line installers and repairers suffered 25 fatal work injuries—a rate of 19 per 100,000 full-time equivalent workers, which is more than five times the national fatal work injury rate.
- While data on energy sector workforce are improving, there are still major shortcomings in the data availability, precision, and categorization of energy sector jobs.

A Modern Workforce for the 21st-Century Electricity Industry

The evolving demands on the electricity industry are causing a number of workforce challenges for the electricity industry, which include large shifts in skills needed and in geographic location of jobs, a skills gap for deploying and operating newer technologies, changes occurring during a period when the industry is facing high levels of retirements, and challenges recruiting and retaining a workforce that reflects the gender and racial diversity of the Nation. At the same time, the evolution of the industry is also creating a number of new workforce opportunities, including jobs in renewable energy, natural gas, and information and communications technology (ICT).

The electricity sector's full potential will only be realized if its workforce is able to appropriately adapt and evolve to meet the needs of the 21st-century electricity system. A skilled workforce that can build, operate, and manage this modernized grid infrastructure is an essential component for the sector's development. Addressing the workforce challenges identified here will create well-paying jobs that contribute to the economic health of local communities, support the increased use of efficiency technologies, reduce injuries and improve worker safety, enable employees in the electricity industry to support a modernized 21st-century energy system, and ensure a resilient electricity system.

Overview of the Electricity Industry Workforce

The electricity system depends on a workforce that fills a diverse set of jobs—from the coal miner extracting fuel from the ground for electricity generation, to the utility worker repairing a distribution line, and everything in between. The following section provides an overview of the number and types of jobs related to the electricity industry.

Workforce Size

The Bureau of Labor Statistics (BLS) reports that nearly half a million people are employed in electric power generation, transmission, and distribution (Table 5-1).[1] Of the 290,000 employees in the electric power transmission and distribution subsector, over a quarter million are employed with distribution companies. There are an additional 600,000 jobs in extraction and mining industries, though only a portion of those jobs are directly attributable to the electricity industry.[2]

Table 5-1. Direct Employment and Income in Industries Related to Electric Power Supply as Tracked by BLS, 2015[3]

Industry Sector/Subsector	Jobs	% Related to Electricity Industry	Average Annual Income
Electric power generation	192,000	100%	$116,000
Electric power transmission and distribution	290,000	100%	$99,000
Total – Electric Power	**482,000**	**100%**	**$106,000**
Coal mining[a]	71,000	~ 80%	$83,000
Oil and gas extraction[b]	540,000	~35% of gas, ~1% of oil	$113,000
Total – Mining and Extraction	**611,000**	**Unknown**	**$110,000**

The Bureau of Labor Statistics reports 482,000 people in the electric power generation, transmission, and distribution. A portion of the over 611,000 jobs in mining and extraction jobs are also in support of the electricity sector.

Note: More than 80 percent of the coal mined in the United States goes to power production.[4] The oil and gas extraction sector is not subdivided and includes many non-power uses. About 35 percent of the natural gas and roughly 1 percent of petroleum usage in the United States is for power production.[5]

In addition to the 482,000 jobs in the electric power generation, transmission, and distribution subsectors, BLS reports that 169,000 people are employed in the Power and Communication Line and Related Structures Construction industry. Some of these employees work constructing transmission lines, substations, and power plants.[6]

The electricity industry is a dynamic industry with changing sources of employment and job categories. As a result, the direct employment figures captured by the BLS job categories provided in Table 5-1 do not include all employment related to the electricity industry, particularly those related to construction, solar, wind, and energy efficiency workers.[7] In 2015, the Department of Energy published the first edition of the "U.S. Energy and Employment Report" (USEER), which provided a broader depiction of electricity industry employment than the BLS data based on supplemental employment surveys. A second edition of the USEER, published

[a] Includes supporting North American Industry Classification System (NAICS) industry categories.

[b] Includes supporting NAICS industry categories.

in January 2017, finds that about 862,000 people are employed in jobs related to electric power generation. Another 1,082,746 are also employed in jobs related to fuels extraction and mining, although not all are directly attributable to the electric power sector (Table 5-2).

Table 5-2. Electric Power Generation and Fuels Extraction and Mining Employment Estimates by Technology, Q1 2016[8]

Technology	Electric Power Generation (Employment Estimates)	Fuels Extraction and Mining (Employment Estimates)
Hydroelectric	65,554	-
Coal	86,035	74,084
Natural Gas	88,242	309,993
Nuclear	68,176	8,592
Solar	373,807	-
Wind	101,738	-
Geothermal	5,768	-
Bioenergy	7,980	104,663
Oil	12,840	502,678
Combined Heat and Power	18,034	-
Other	32,695	82,736
Total	**860,869**	**1,082,746**

The "U.S. Energy and Employment Report" provides a broader accounting than the Bureau of Labor Statistics data presented above, and it finds that as of the first quarter of 2016, over 860,000 people were employed in the electric power generation industry, most of which are related to the construction and buildout of new solar and wind generation capacity. Another 1,082,746 are also employed in jobs related to fuels extraction and mining, although not all of these are directly attributable to the electric power sector. As noted above, over 80 percent of coal, 35 percent of the natural gas, and 1 percent of petroleum usage in the United States are for power production.[9]

USEER finds that the BLS estimates are particularly low for jobs associated with solar, wind, geothermal, and biomass electric power generation.[10] These low estimates result from classifying many jobs in these industries as construction or business and professional services employment. For instance, most solar company installers are classified as electrical contractors.[11]

Though BLS does not estimate employment in energy efficiency jobs, USEER found that 2.2 million people are working in industries directly or partially related to energy efficiency—more than 2.5 times the number employed by electric power generation. Of those 2.2 million, 1.4 million are in the construction industry.[12] Energy efficiency employment includes both the production of energy-saving products and the provision of services that reduce end-use energy consumption. However, USEER estimates only include work with efficient technologies or building design and retrofits. They do not capture employment related to energy-efficient manufacturing processes. If process efficiencies were included, estimates for the energy efficiency workforce would be even larger.

5.2.2 Electricity Industry Skills and Training

The electricity industry offers diverse jobs, which require a variety of skills. Table 5-3 includes job descriptions and educational requirements for selected job categories across the utility portion of the electricity industry. Traditional jobs, such as lineman, will continue to be needed, but the increase of renewable energy, as well as an increased ICT component to the electricity industry, will change the skillset required for many jobs in the electricity system of the 21st century.

Table 5-3. Typical Electricity Workforce Roles and Required Education or Training[13]

Job Category	Job Description	Required Education: High School	Vocational	Apprenticeship	Associates	Bachelors	Masters	Doctorate
Lineman	Responsible for the installation and repair of overhead and underground distribution and transmission lines, poles, transformers, and other equipment.							
Power Plant Operator	Responsible for the maintenance and operation of all primary and auxiliary equipment required to generate electricity or meet natural gas customers' demands.							
Technicians (Transmission and Distribution)	Responsible for the repair of both electrical and mechanical equipment. This includes inspecting and testing electrical equipment in generating stations and substations.							
Technicians (Generation)	Responsible for the construction, assembly, maintenance, and repair of steam boilers and boiler house auxiliary equipment.							
Pipefitters and Pipelayers (Generation)	Responsible for the installation and maintenance of pipe systems and related equipment for steam, hot water, heating, sprinkling, and industrial production and processing systems.							
Power Engineers	Focus on electrical systems, equipment, and facilities rather than on mechanical systems and other non-electrical systems involved in electric and natural gas energy services. It includes people involved in planning, research, design, development, construction, installation, and operation of equipment, facilities, and systems for the safe, reliable, and economic generation, transmission, distribution, consumption, and control of electricity.							
All Other Engineers	Focus on non-electrical systems, processes, equipment, and facilities involved in electric energy services. It includes people involved in the planning, research, design, development, construction, installation, and operation of equipment, facilities, and systems for the safe, reliable, and economic generation/supply, transmission, distribution, consumption, and control of electricity.							

The electricity workforce includes several job categories, each with specific educational requirements (shown in green). The gray boxes show where a specific level of education is sometimes required or infrequently required.

One ongoing challenge for maintaining the electric industry workforce is the amount of time required to train new workers. For example, training to become a journeyman line worker can take up to 7 years.[14] If enrollment in apprenticeships and training programs increases during a period of worker shortage, the new employees would not be prepared for the full range of line worker duties for several years.[15] The electricity industry appears to have made progress on maintaining a pipeline of skilled labor; the number of pre-apprenticeship training programs has more than tripled since the 1990s.[16, 17] Furthermore, skilled workers coming from related industries—such as construction electricians—may not require as much training and would be ready for duty in a shorter timeframe.

In addition to the electricity workforce job categories shown in Table 5-3, the electricity industry also employs thousands of corporate services employees engaged in jobs such as customer service, finance, management, and human relations. Skills required in these jobs are often more transferable between industries and require less specialized electricity industry training.

Training Programs in the Electricity Industry between the 1980s and Today

The economic outlook of an industry often determines the availability of training programs. During the 1980s and 1990s, the electricity industry experienced much lower demand growth than the decade before. A conservative outlook on demand growth coupled with an increased focus on productivity in anticipation of impending industry deregulation led utilities to scale back hiring and internal training programs.[c]

The 1980s and 1990s also coincided with a shift away from technical education as the primary tool to train the next generation, toward a larger emphasis on 4-year college programs. This shift further decreased the interest in technical and vocational training, previously a main pillar of education for the electricity industry workforce, which led to the closure of many technical high schools, shrinking the pool of available applicants for the electricity industry even further.[d] The future workforce is now educated through a variety of means, including community colleges, apprenticeship programs, and certificate programs. This has led to a lack of uniformity of standards and curricula, which is a challenge for electric companies, as they often have to retest skills to ensure that applicants have the necessary education. While the 2000s have seen a rebuilding of some of the training and apprenticeship programs, the dip in training programs in the 1980s contributed to fewer workers in middle management in the electric utilities—creating a gap as the large number of baby boomers retire.[e]

[c] Marika Tatsutani, *National Commission on Energy Policy's Task Force on America's Future Energy Jobs* (Washington, DC: Bipartisan Policy Center, 2009), 14, http://bipartisanpolicy.org/wp-content/uploads/sites/default/files/NCEP%20Task%20Force%20on%20America's%20Future%20Energy%20Jobs%20-%20Final%20Report.pdf.

[d] Marika Tatsutani, *National Commission on Energy Policy's Task Force on America's Future Energy Jobs* (Washington, DC: Bipartisan Policy Center, 2009), 45, http://bipartisanpolicy.org/wp-content/uploads/sites/default/files/NCEP%20Task%20Force%20on%20America's%20Future%20Energy%20Jobs%20-%20Final%20Report.pdf.

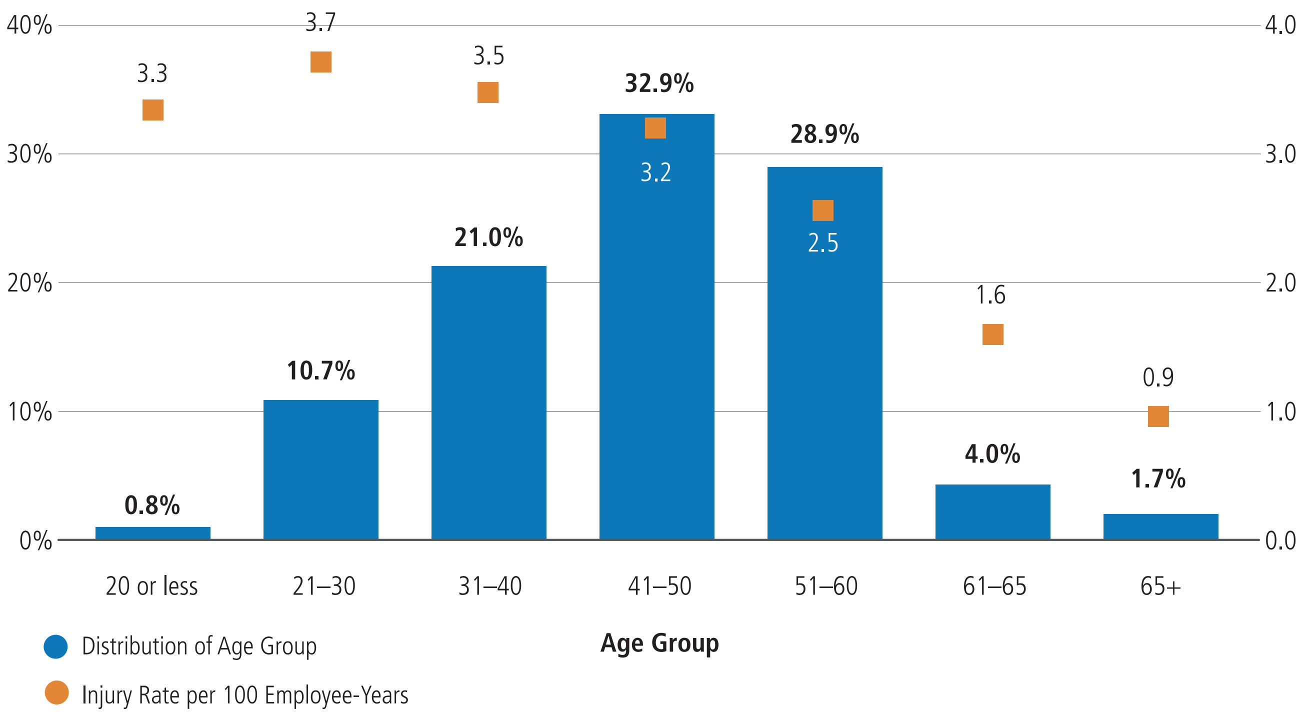
[e] Marika Tatsutani, *National Commission on Energy Policy's Task Force on America's Future Energy Jobs* (Washington, DC: Bipartisan Policy Center, 2009), http://bipartisanpolicy.org/wp-content/uploads/sites/default/files/NCEP%20Task%20Force%20on%20America's%20Future%20Energy%20Jobs%20-%20Final%20Report.pdf.

Electric Utility Worker Health and Safety

The electricity industry has made progress in improving workplace safety. From 1995 to 2013, the number of injuries[f] per 100 employee-years in electricity utilities decreased from 4.7 to 1.3.[18] In 2015, the workplace injury rate across electricity generation, transmission, and distribution companies was slightly more than half the national rate.[19] However line workers continue to experience hazardous working conditions. In 2014, electrical power line installers and repairers suffered 25 fatal work injuries—a rate of 19 per 100,000 full-time equivalent workers, which is over five times the national fatal work injury rate.[20]

For electricity utility workers, the injury rate is highest among the 21–30-year-old age group at 3.7 percent (Figure 5-1). This segment only makes up 10.7 percent of the sector workforce, but has higher rates of injury due to "fewer years of experience and a higher proportion of young workers employed in higher risk occupations, performing physically demanding or higher risk tasks."[21]

Figure 5-1. Injury Rates and Employee Age Group Distribution for Electricity Utilities, 1995–2013[22]



Overall injury rates are highest among the 21–30-year-old group, although employees between 41 and 50 years of age comprise the largest group of employees, with 32.9 percent.

Injury rates for electricity utilities are not only unevenly distributed by age group, they also differ regarding the nature of the job. Welders, line workers, and meter readers accounted for the highest proportion of injuries among all electricity power sector occupations.[23] The specific causes of worker injuries and fatalities can be generally grouped into four categories: a misunderstanding or noncompliance with safety concepts, poor communication, absence of leadership, and/or lack of experience and qualified employees.[24]

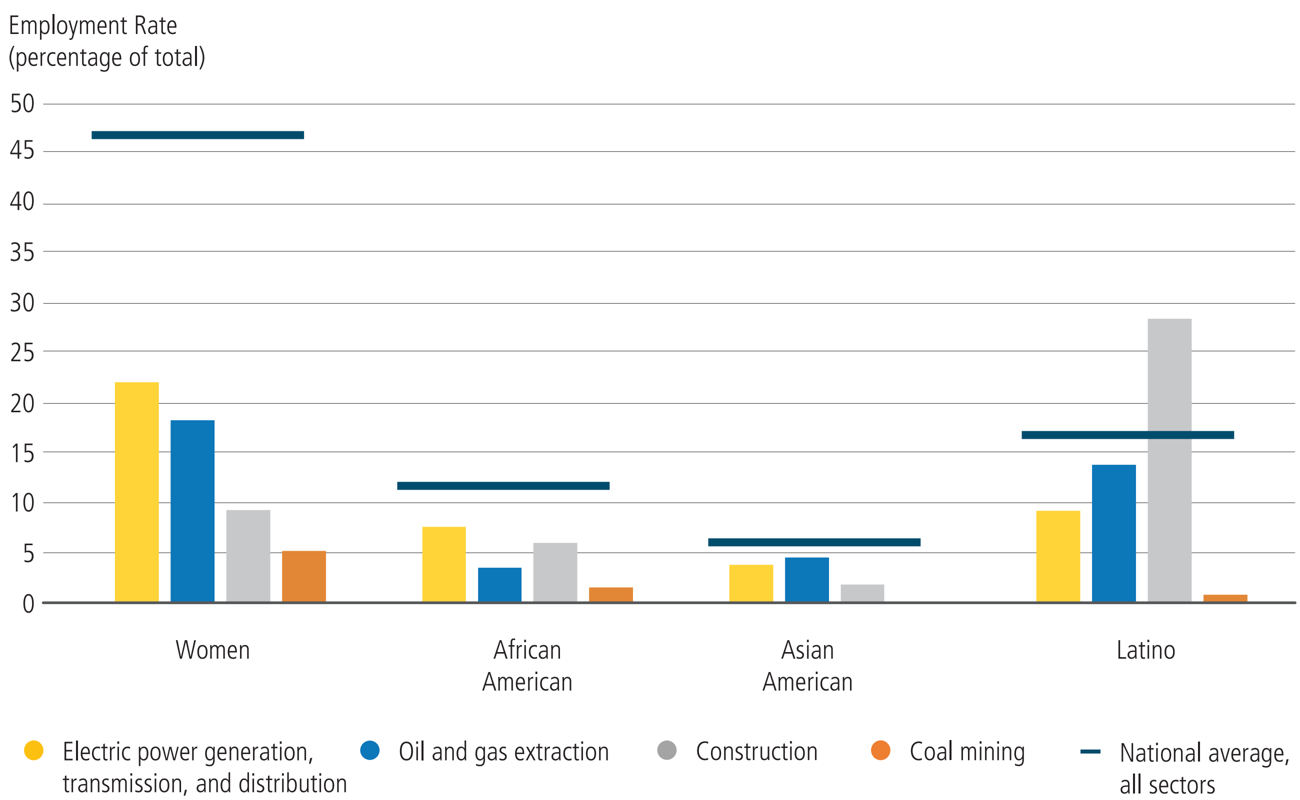
[f] Injury rates reported here are for injuries resulting in a worker missing at least one full day of work after the injury date.

As the electricity sector modernizes, there may be opportunities to leverage technological advances to improve worker safety and reduce rates of injury. New equipment, processes, and infrastructure design can complement innovations in training practices to improve workplace safety in the electricity industry by reducing electrical exposures, instances where utilities deploy crews and trucks, and instances where crews work at elevated heights.

Electricity Industry Workforce Inclusion

The electricity and related resource extraction industries employ fewer women and minorities than the national average (Figure 5-2). Women constitute 22 percent of the electric power generation, transmission, and distribution industry workforce, compared to 47 percent of the entire workforce. African Americans constitute just 8 percent of the electricity workforce, but are 12 percent of the workforce as a whole. Oil and gas extraction, construction, and coal mining industries employ even fewer women and African Americans. Asian Americans are not statistically represented in the coal mining industry and, again, lag the national average for the other industries surveyed here. Latino employment in the construction industry is the only minority demographic that is higher than the national average for the population groups and industries included here.[25]

Figure 5-2. Electricity and Related Industry Employment Demographic Indicators, 2015[26]



The electricity industry ranks far below the national average in employment of women, African Americans, Asian Americans, and Latinos. The oil and gas extraction and coal mining industries have similar demographic characteristics. The construction industry, where energy efficiency jobs are mostly located, has a higher percentage of employment of Latino Americans.

The lack of diversity in the electricity industry extends to the executive level as well—only 5 percent of the boards of utilities in the United States in 2015 included any women, and approximately 13 percent of board members among the top 10 publicly owned utilities were African American or Latino.[27, 28]

Veterans make up a slightly higher proportion of electricity industry jobs than their representation in the national workforce. A recent study found that veterans make up 8 percent of the current workforce and 10 percent of new hires across the electricity utility, natural gas utility, and nuclear energy industries.[29] The solar industry employed an estimated 16,835 U.S. veterans in 2015, and the percentages of veterans working as solar manufacturers, solar installers, and solar project developers each exceeded the total percentage of veterans in the broader national workforce.[30]

Underrepresentation in or lack of access to science, technology, engineering, and mathematics (STEM) educational opportunities and programs contribute to the underrepresentation of minorities and women within the electricity industry. For instance, African American and Latino students are critically underrepresented in STEM programs in high schools and colleges, and STEM education is often necessary for entry into many positions in the electricity sector. Two-thirds of public high schools with a majority of African American students do not offer calculus, and more than half do not offer physics.[31] These curricula deficits result in lower STEM college graduation rates among underrepresented communities. In the 2013–2014 school year, African Americans and Latinos received only 7.2 percent and 9.5 percent of all STEM bachelor's degrees, respectively.[32]

While the renewable portion of the electricity industry is seeing dynamic job growth, workforce inclusion in renewable energy also tends to lag behind the national average. Women represented 24 percent of the solar workforce, which is well below the national average workforce participation levels. However, the number of women in the solar industry has been steadily trending upward from 19 percent in 2013. This trend is reversed for African Americans and Latinos, who are trending downward, with African Americans comprising 5.2 percent of the solar workforce in 2015 (down from 5.9 percent in 2013), and Latinos accounting for 11 percent of the workforce in 2015 (down from 16 percent in 2013). The number of veterans in the solar workforce is also trending downward—9.2 percent in 2013 and 8.1 percent in 2015, but it is still above the national average.[33]

Electricity Industry Workforce Challenges

The electricity industry is facing several changes that present challenges for maintaining a skilled workforce. New technologies require new and evolving skillsets for industry employees as high levels of retirees take with them industry experience, and regional mismatches are emerging between the needed and available workforce. These changes could create skills gaps for the industry and workforce, as well as recruitment challenges in attracting appropriately trained and qualified employees. The time required to train new, qualified workers in the sector serves to limit the industry's ability to respond to rapid shifts in the workforce and limit the employment appeal to prospective employees faced with alternative career options. Workforce challenges facing the industry are exacerbated by the lack of robust, reliable data and by forecasts on industry needs and workforce supply—especially as business models evolve. Meanwhile, new technologies like distributed generation, smart home devices, and electric battery storage have led to the proliferation of many new business, job types, and employment opportunities. These new business models are expanding the definition of electricity industry jobs, and they present new workforce development challenges related to skills transferability and uniform safety and security practices and services.

The electricity system of the 21st century will require an adaptable and flexible workforce with additional areas of expertise and capabilities than the current workforce. The integration of variable renewable sources, storage systems, smart grid, and demand management will require new training and skillsets. Sector engineers need to have well-developed expertise in traditional topics such as electrical engineering, while also possessing knowledge of information technology, communications, and other relevant topics. Maintaining existing training programs for the legacy systems while also focusing on the skillsets of tomorrow's workers will be a unique challenge. As an example of these new workforce needs, the increased ICT component in the smart grid of the 21st century requires a wide array of new and different skills.[34]

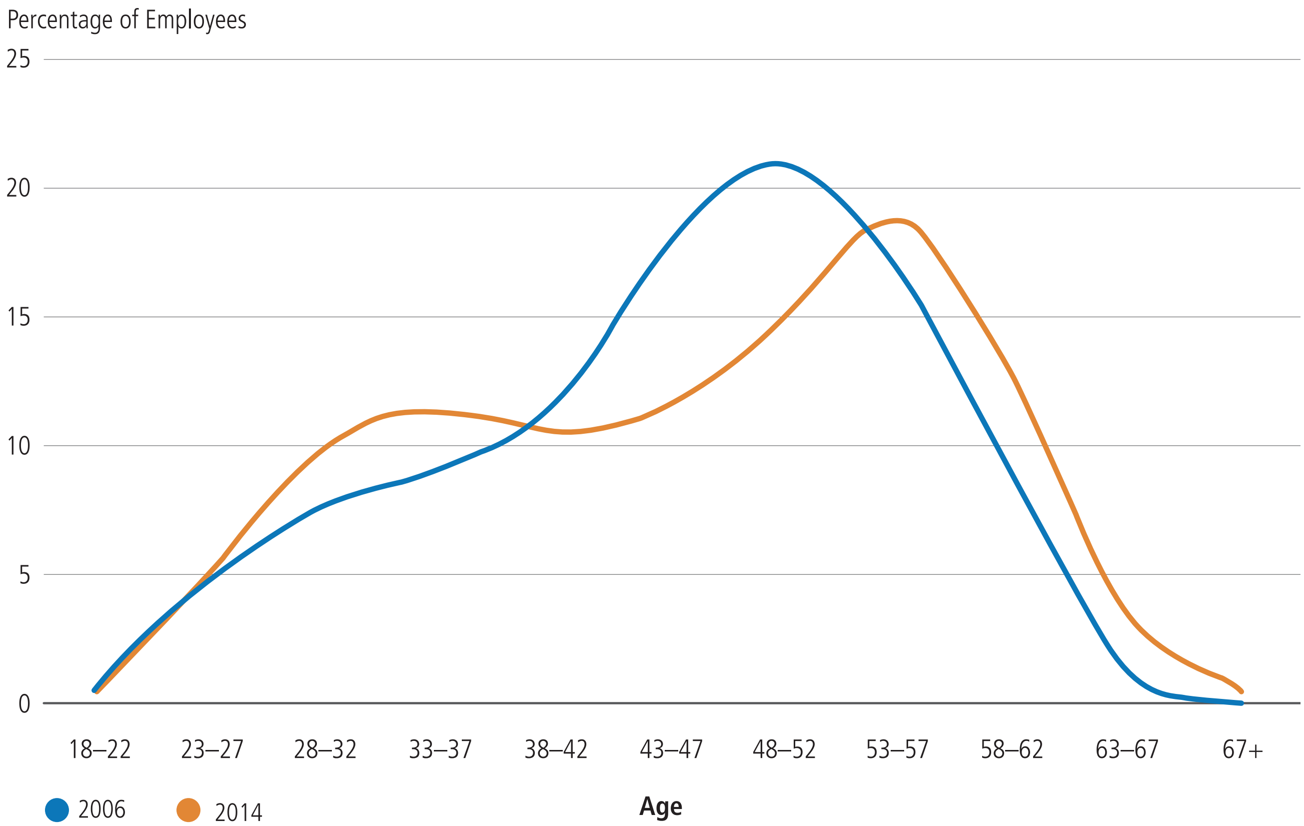
With the issue of cybersecurity increasingly at the forefront of electricity industry concern, the industry will require a workforce adept in risk assessment and behavioral science, as well as familiar with cybersecurity risk factors.[35] A 2010 report from the President's Council of Advisors on Science and Technology, "Designing a Digital Future," highlighted challenges stemming from the lack of a dedicated and trained cross-disciplinary power grid workforce that can comprehend, design, and manage cyber-physical systems (CPS).[36] In the future, the electricity industry faces dual challenges of growing a workforce with new requirements and qualifications, while also competing with other industries that are demanding CPS-trained workers. Training, curricula, and education in CPS remains nascent. The shortage of CPS-trained workers could place constraints on the evolution of the 21st-century electricity system. Addressing those ICT and sectoral skills challenges requires a strategic approach to talent management, focused on upgrading skills for existing employees and recruiting new employees with needed skills.

Electricity Industry Capacity Gaps

Much of the utility and electricity sector workforce is nearing retirement. The aging workforce of the electricity sector is not unique in the U.S. economy, yet its specific skills requirements and the importance of the industry to national security and economic prosperity elevate the importance of its workforce management. Electricity utility, natural gas utility, and nuclear generation industry surveys indicate that roughly 25 percent of employees will be ready to retire in the next 5 years.[37] Noting demographic trends within the industry, in 2006, the North American Electric Reliability Council (NERC) raised concerns about worker and skills gaps among electricity industry employees, stating that "industry action is urgently needed to meet the expected 25 percent increase in demand for engineering professionals by 2015."[38] Spurred by this and other reports, the industry has pursued multiple initiatives and programs to address the looming increase in demand for skilled workforce.

Although the industry has made some progress on recruiting and developing the next-generation workforce through hiring (Figure 5-3), the capacity gap remains stubbornly persistent due to a workforce that continues to age, recruitment difficulties, a rapidly changing industry, and specific training and certification needs.[39] A recent industry study forecasts the need for 105,000 new workers in the smart grid and electric utility industry by 2030, but expects that only 25,000 existing industry personnel are interested in filling those positions.[40] The remaining 80,000 employees in this supply-demand mismatch will need to be filled through recruiting and training. However, the industry is not expected to meet the forecasted need with its current recruitment and training rates.[41] In one recent survey, 43 percent of utilities surveyed stated that they see the aging workforce and the increased rate of retirements as one of their top three most pressing challenges.[42]

Figure 5-3. Age Distribution in Electric and Natural Gas Utilities, 2006–2014[43]



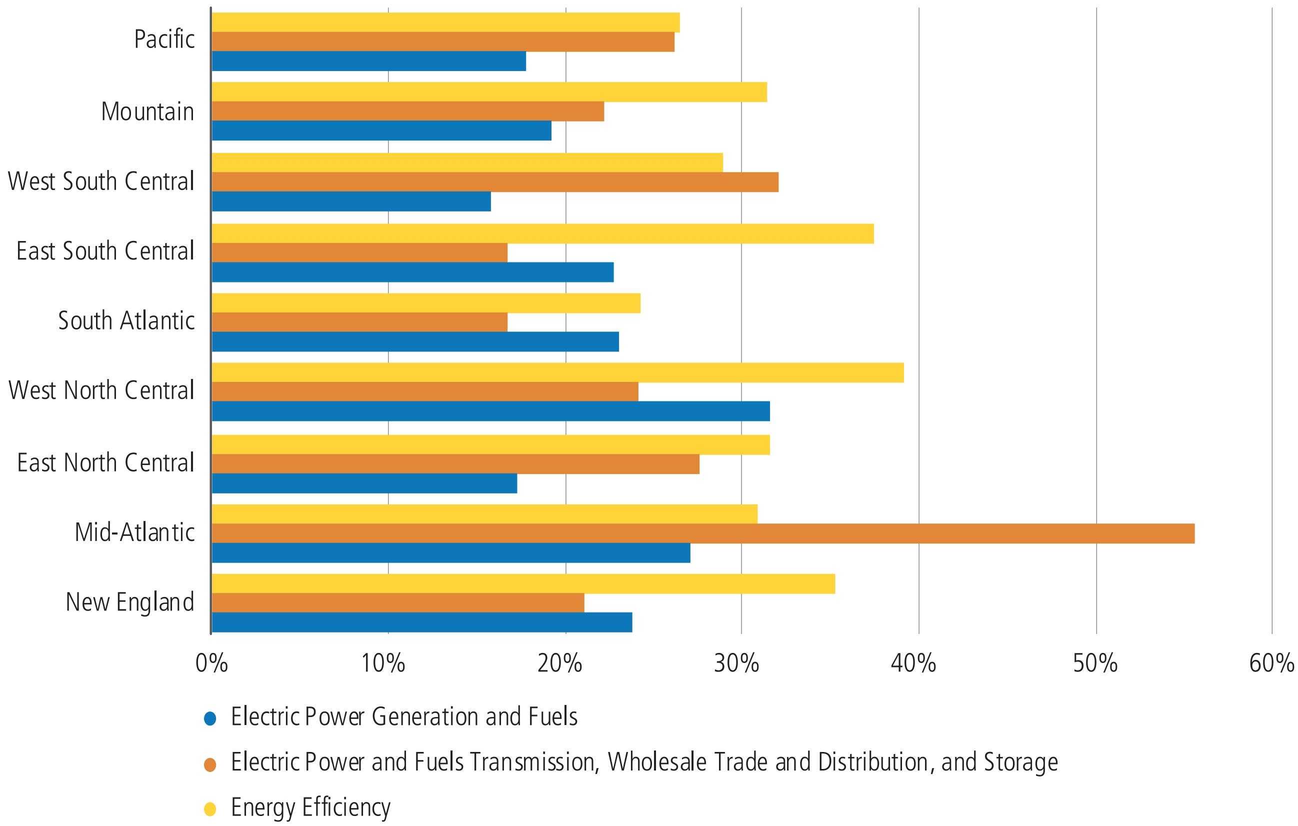
The age distribution in electric and natural gas utilities has shifted between 2006 and 2014, reflecting both the higher proportion of the workforce that is nearing retirement and industry efforts to address the aging workforce by hiring younger employees.

Electricity Industry Employee Recruitment Challenges

As workers retire, the electricity sector is experiencing challenges in hiring replacement personnel. Industry hiring managers often report that lack of candidate training, experience, or technical skills are major reasons why replacement personnel can be challenging to find—especially in electric power generation.[44] This lack of experience can, in part, be attributed to hiring slow-downs in the 1990s and 2000s that have resulted in a current shortage of mid-career professionals with the experience to take on supervisory roles (see "Training Programs in the Electricity Industry between 1980 and Today" textbox).[45]

According to survey responses, over half of employers in the Mid-Atlantic region report very high difficulty with hiring in the electric power and fuels transmission, wholesale trade and distribution, and storage subsector, while no more than 32 percent of employers in other regions reported hiring difficulty in this field (Figure 5-4). The Mid-Atlantic region, home to more than 40 million people and Washington, D.C., also reports among the highest rates of difficulty hiring in the energy efficiency and electric power generation and fuels industries.[46, 47]

Figure 5-4. Percentage of Employers Reporting Very High Hiring Difficulty by Census Region and Subsector, Q4 2015[48]



Over half of employers in the Mid-Atlantic region report very high difficulty hiring in the electric power and fuels transmission, wholesale trade and distribution, and storage subsector, while no more than 32 percent of employers in other regions reported hiring difficulty in this field. The Mid-Atlantic also reports among the highest rates of difficulty hiring in the energy efficiency and electric power generation and fuels industries.

The employment supply and demand imbalance is already evident in the electric power transmission industry. One analysis finds that 10 states were experiencing a shortage of workers for electric power transmission in 2014. The same analysis projects that the number of states that will experience a shortage of worker supply will grow to at least 12 by 2018.[49]

Training Capacity and Timeline

One of the challenges for maintaining the electric sector workforce is the amount of time required to train new workers in response to changing industry needs. Even if enrollment in apprenticeships and training programs increased today, sector employees would not be ready to enter the job market until several years from now. For example, initial training to become a fully educated line worker is between 4.5 and 7 years.[50] And, due to the closure of many training programs in the 1980s because of lower need (see "Training Programs in the Electricity Industry between 1980 and Today" textbox), there is also a dearth of mid-career employees within the electricity sector that might otherwise fill these roles (Figure 5-3).[51]

Electricity Industry Sectoral and Regional Variations, Training Opportunities

The electricity industry is the dominant consumer of coal, natural gas, and renewable energy technologies, so changes in electricity industry demand for these resources can cause separate regional and sectoral dislocations in these industries. Each industry has distinctive workforce characteristics, skills requirements, and geographic concentrations, which means that employment gains in one industry do not always translate to opportunities to workers affected by employment loss in other industries that may be geographically distant and require different skills.

In many cases, changes in the electricity industry result in new businesses and sources of employment, especially with the growth of natural gas production and the renewable energy industry. In other parts of the country where employment is heavily dependent on a single industry, like coal, the economic consequences of the shifts in the electricity industry can be significant; employment in the coal mining industry has fallen by nearly 70 percent over the last three decades, largely in rural America.[52] Even in sectors experiencing long-term growth, employment can be volatile; the oil and natural gas extraction industry has lost about 14 percent of its workforce since the beginning of 2015 (through August 2016).[53] These changes in employment not only impact the labor force, but also the communities in which they live, work, and contribute to funding public infrastructure and services like roads and schools. While the shift from jobs in coal to natural gas and renewables is a recent example of job dislocation, this issue is not limited to coal or to the energy industry as a whole. Job dislocation has been, and will continue to be, a critical issue across many industries as the Nation's economy grows and changes.

Falling Demand for Coal Has Reduced Coal-Related Employment

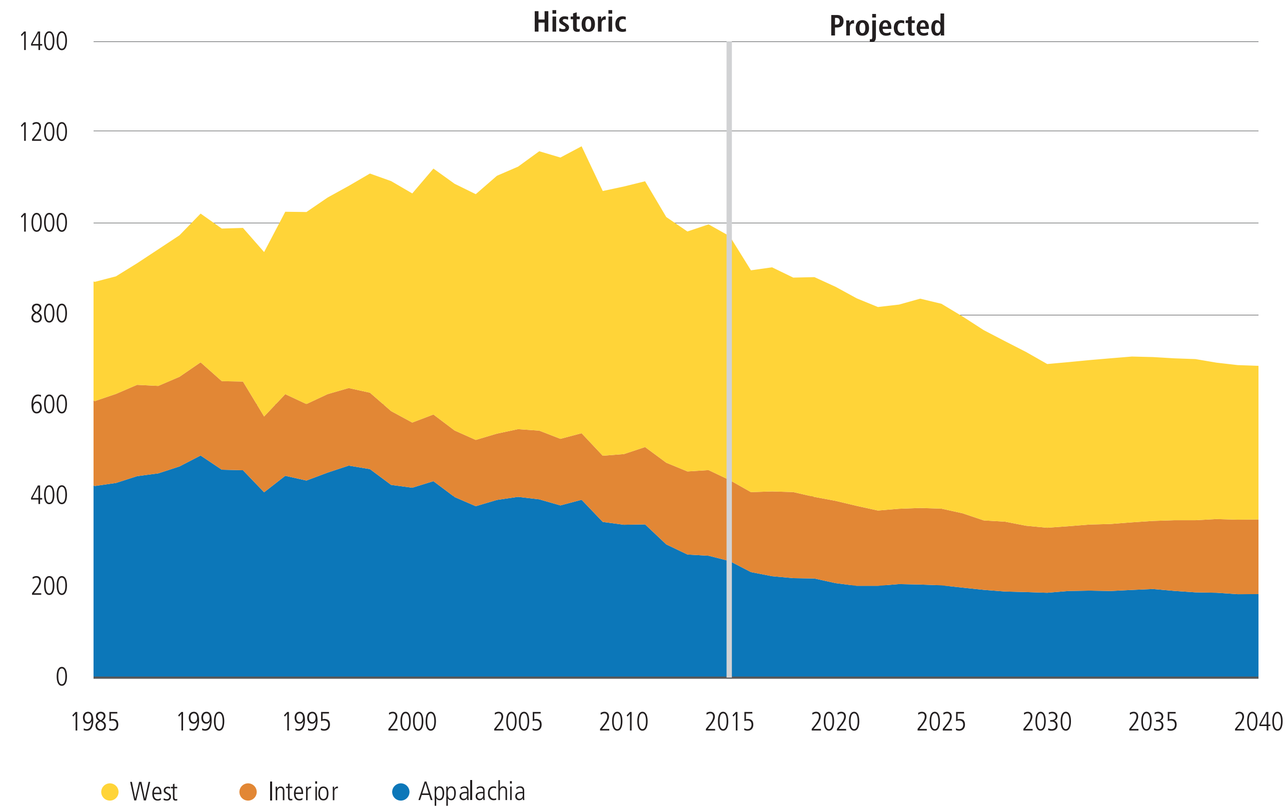
In 2015, the electricity industry consumed more than 80 percent of domestically produced coal.[54] Recent shifts away from coal for electricity generation and toward natural gas and renewable energy technologies—largely driven by recent reductions in natural gas prices and renewable generation costs—have sharply reduced overall coal demand over the past several years. Annual coal production in 2015 was at its lowest level since 1986.[55] Because of the reduction in electricity industry demand and other shifts in the economy, coal production is forecast to continue declining over the coming decades (Figure 5-5).

Coal production in the Appalachian region began falling in 1990, even as total U.S. coal production increased through 2007. The primary reason for coal's reduced market share in Appalachia is its higher relative price compared to coal in the western United States; in 2015, the price of coal from West Virginia was four times as much per ton as coal from Wyoming.[56]

Differences in mining efficiency and ownership cause the higher cost for Appalachian coal. Mines in the West tend to be larger and use surface mining techniques, which result in lower production expenses compared to the mix of underground and surface mining used in Appalachia.[57] While most mining in Appalachia occurs on private lands, 80 percent of coal production in the western United States occurs on Federal lands, where companies pay lower royalties and fees.[58] Appalachian coal's relative economic disadvantage is forecast to continue for the coming decades (Figure 5-5).[59]

Figure 5-5. Historic and Projected Coal Production, 1985–2040[60, 61]

(Million Short Tons)



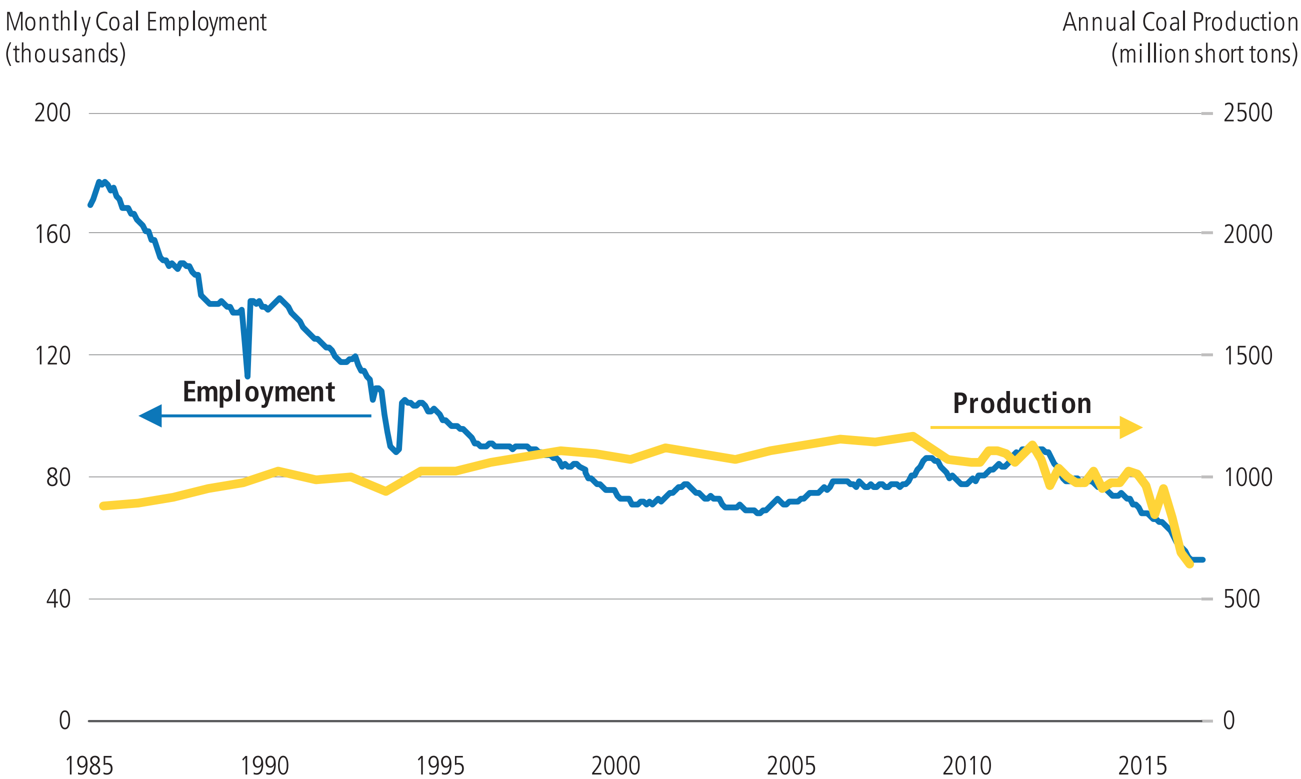
Coal production in the United States peaked in 2008 after a period of decreasing production in Appalachia and increasing production in the West. Production is forecast to continue to fall in the business-as-usual scenario shown here.

Coal mining jobs in the United States have declined over the last several decades. Between 1985 and 2000, employment in the coal industry shrank nearly 60 percent. During this period, 105,500 domestic coal jobs were lost. While national coal mining employment experienced a minor increase from 2000–2011, 36,000 coal mining jobs were lost between 2011 and September 2016, a 40 percent reduction.[g] Of these losses, nearly 90 percent were in the Appalachian region. As of November 2016, the BLS reported employment of about 53,000[h] people in the coal mining industry (Figure 5-6).[62]

[g] The base year used for this comparison is 2011 because it was the peak year for domestic coal production this century. Since then, coal mining jobs have been declining, while natural gas and oil extraction jobs have been on the rise overall.

[h] The 2017 "U.S. Energy and Employment Report" records higher coal fuels employment numbers in comparison to BLS due to differences in terms, categorizations, and survey methods; it reports 74,084 coal fuels jobs in March 2016, as shown in Table 5-2. The BLS data is relied upon here to illustrate both the recent trends and the historical record over many decades.

Figure 5-6. Coal Industry Employment and Production, January 1985–September 2016[63, 64]

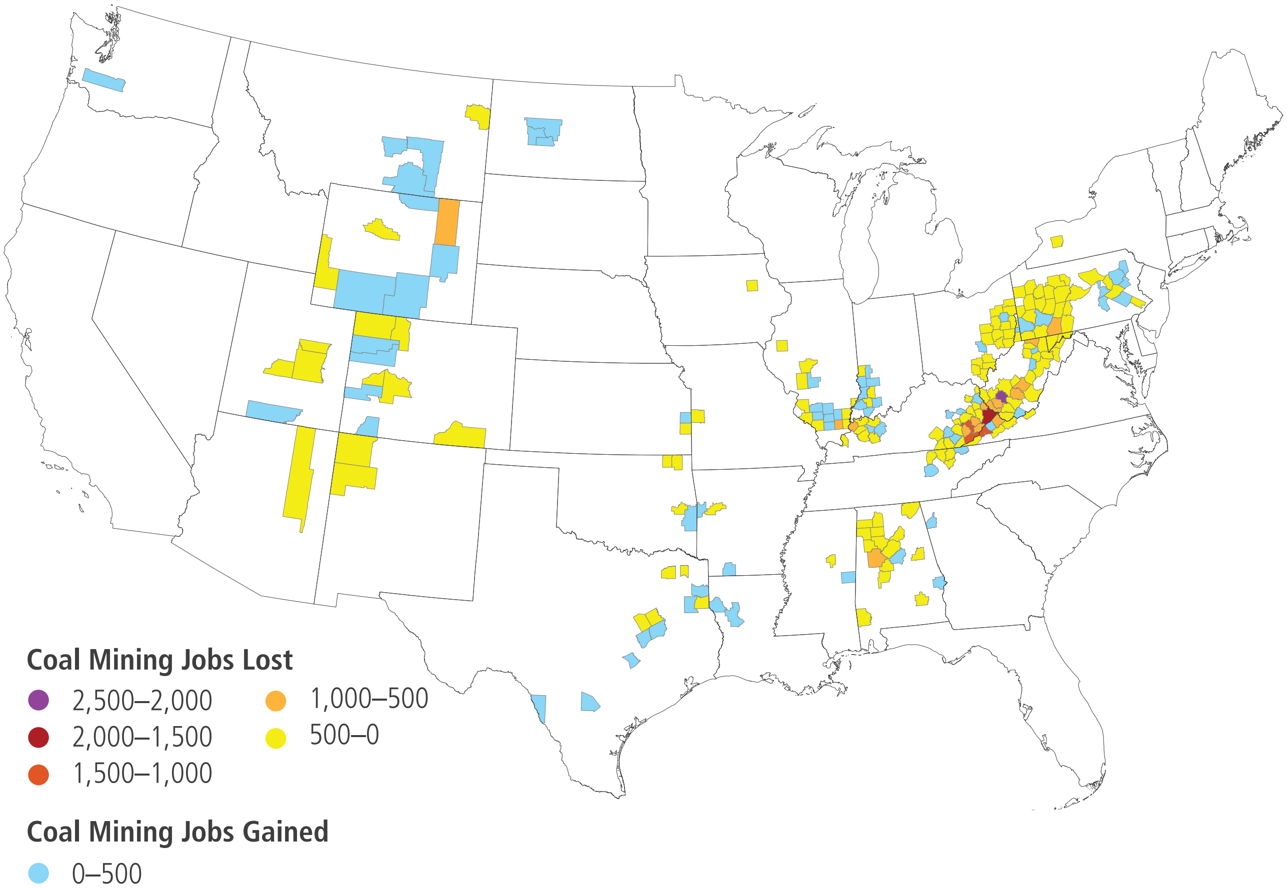


Employment in the coal industry fell from 1985 through 2003 even while coal production increased during this period. This employment reduction was due to mechanization and a shift to western coal that has much higher labor productivity than Appalachian mines. Over 23,000 jobs were lost between 2011 and 2015 while coal production decreased; nearly 90 percent of those losses were in the Appalachian region. Note: Data from 2010 to 2016 are quarterly, extrapolated to annual estimates.

This loss of coal jobs can be attributed to increased efficiencies in mining and, later, a reduction in coal demand over the last several decades. Between 1985 and 2001, coal production increased 28 percent, as industry employment fell by 59 percent, due to the increased efficiencies in the industry and by the shifting of production and lower sulfur coal produced by shifting production from Appalachia to the Western United States, especially within the Powder River Basin.[65, 66] From 2001 to 2015, annual mining productivity in Appalachia ranged from 5,100 tons per employee to 8,100 tons per employee; in the West, it ranged from 35,000 tons per employee to 45,000 tons per employee.[67]

Coal miners provide crucial economic support for the communities in which they live, which tend to be concentrated in rural areas. In 2011, at the peak of coal mining employment in this century, coal mining jobs accounted for more than 5 percent of employment in 64 U.S. counties and over 20 percent in 12 counties, not including indirect employment supporting the coal sector. Fifty of the counties with over 5 percent coal mining employment experienced job losses between 2011 and 2015.[68, 69] The total net job loss in the 64 counties was over 20,000 jobs, with 12 counties losing more than 10 percent of their entire workforce.[70, 71] These counties that have been hit particularly hard by recent employment declines are located primarily in central and northern Appalachia (Figure 5-7).

Figure 5-7. Change in Coal Mining Employment by County, 2011–2015[72]



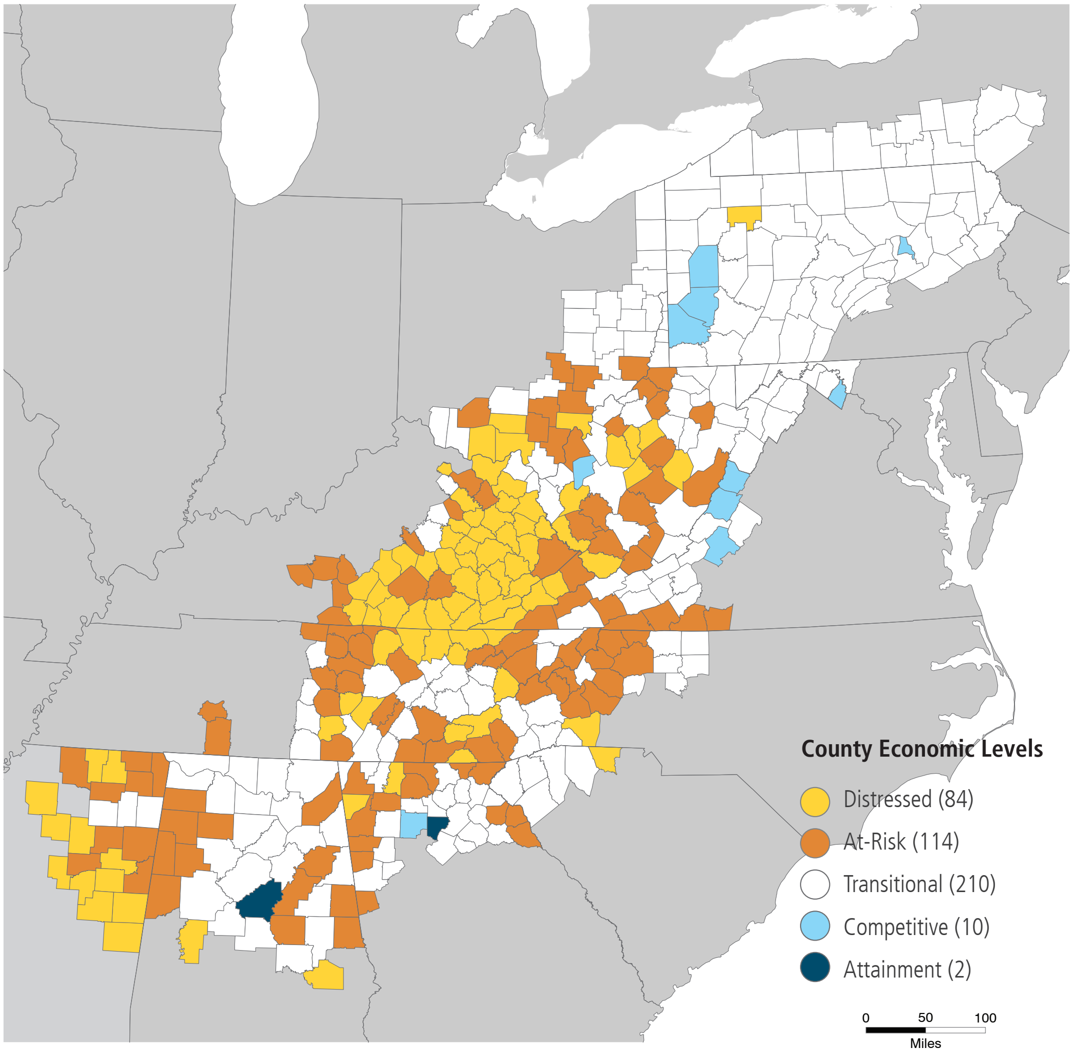
Nationally, 161 counties experienced coal industry job losses between 2011 and 2015, when over 20,000 jobs were lost in total. The most severe job losses are concentrated in central and northern Appalachia, where some regions have a high proportion of their workforce in the coal industry.

Coal mining is a major economic driver within many rural communities. Coal mining jobs pay well relative to other available occupations in those areas; miners earn roughly 40 percent more than the average wage for all U.S. workers.[73] The combination of relatively high income and employment concentration means that many local economies are very sensitive to changes in the industry.[74] A reduction in jobs lowers municipal tax revenues, severely impacting support for public schools, local infrastructure, and public services. Less spending at local businesses depresses the local economy, causing more unemployment and further reducing public revenue.

There are 1.8 million people living in Appalachian counties with ongoing coal-mining activity and classified as "economically distressed" or "economically at risk" by the Appalachian Regional Commission (ARC) based on a combined index of unemployment, poverty, and income levels.[i, 75, 76] These counties are heavily concentrated in West Virginia, eastern Kentucky, and southern Ohio, largely overlapping with regions facing coal industry employment losses (Figure 5-8).

[i] The Appalachian Regional Commission ranks all U.S. counties according to a combined index of unemployment, poverty, and income, and it considers counties in the bottom decile for the country to be "distressed" and the bottom quartile to be "at risk."

Figure 5-8. Economic Wellbeing of Appalachian Counties, 2016[77, 78]



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More than 45 percent of the mining workforce is over 45 years old.[79] For these employees, finding alternative employment—especially at a similar income level—can be more challenging than for younger workers with more time ahead of them in the labor force.[80] Underfunded pension and retiree healthcare obligations put these older workers, retired miners, and their communities in a particularly vulnerable position. Federal efforts to support economically vulnerable communities and workers are discussed in later sections of this chapter.

Coal miner pension funds are in financial distress, putting retirees and surviving dependents in jeopardy of losing their planned retirement and healthcare benefits. As coal employment has declined, mine worker pensions have some of the highest ratios of retirees to current workers of any pension programs in the United States, which can drain the principal balance of the fund faster than it can be replenished. The largest coal miner pension fund, United Mine Workers of America's 1974 Pension Plan, has 90,000 beneficiaries, with only 8,000 working members still contributing to the fund—a 9 percent ratio of contributing workers to active beneficiaries.[81] On average, 37 percent of pension participants in federally guaranteed, multi-employer pensions are still working and contributing to their pension funds.[82]

The financial crisis and the bankruptcy of three of the largest coal mining companies in the United States between 2014 and 2016 have further imperiled these pension and healthcare programs. These bankruptcies have allowed several large coal companies, including Patriot Coal and Alpha Natural Resource, to default on some or all of their obligations to these pension and healthcare funds.[83, 84] The miners' pension funds are insured by the Pension Benefit Guaranty Corporation (PBGC), a Federal corporation analogous to the Federal Deposit Insurance Corporation and funded out of insurance premiums paid by member pension funds. The 1974 Pension Plan is so large that its default could lead to the insolvency of the PBGC, imperiling retirements across the economy.[85] Retiree health insurance programs have no similar Federal guarantee.[86] Typically, a single employer providing retiree health insurance is not required to pre-fund such obligations, and, in bankruptcy, may be relieved of the obligation to fulfill its commitments.[87] Historically, the Federal Government has intervened to support coal miner retiree benefits in times of crisis through legislative and administrative actions.[88] President Obama's fiscal year (FY) 2016 and FY 2017 budgets included the transfer of Federal funds to protect the health and pension benefits of retired coal miners and their families, as did bipartisan legislation in the Senate and House. However, the 114th Congress adjourned at the end of 2016 without passing this legislation and instead only extended healthcare coverage to retired miners and their dependents through the term of the Continuing Resolution (April 28, 2017).

Continued reductions in coal production in Appalachia are also frustrating efforts to protect community health and the environment against land and water degradation from pre-1977 mining activities. Since 1977, the coal industry has taken responsibility for the remediation of the lands and waters affected by mining, as required by the Surface Mining Control and Reclamation Act of 1977 (SMCRA). However, prior mining activity has left an estimated $4 billion of high-priority, health-related and safety-related issues with abandoned mine lands in the United States[89] and up to $9 billion of abandoned coal mine sites needing restoration.[90] SMCRA created the Abandoned Mine Lands Reclamation Fund (AML Fund) to reclaim land damaged before 1977 using funds collected through a small per-ton fee—currently less than 1 percent of retail value—on all coal mined in the United States.[91]

Declining coal production has reduced funding for abandoned mine reclamation. AML Fund receipts have declined from a peak in 2007 of $305 million to $197 million in 2016.[92] At this revenue level, it would take 20 years to fully fund the high-priority, health-related and safety-related coal mine reclamation in the United States—the majority located in Appalachia.

The current formula for distributing AML Fund resources poorly matches regional needs. Until 2023, SMCRA requires that 50 percent of the fees collected for AML Fund restoration are spent in the state in which they are collected. Most U.S. coal is produced in the western United States, where little need for pre-1977 mine reclamation remains. Meanwhile, disbursements to Appalachia—the historic heart of coal production, where mine reclamation needs are most severe—have fallen due to declining coal production in that region. The President's FY 2016 and FY 2017 budgets proposed to invest $1 billion over 5 years from the remaining unappropriated balance in the AML Fund. The proposal would allow states and Native American tribes across the country to accelerate efforts to clean up abandoned mine lands and polluted waters, then link those projects with economic development strategies to revitalize coal communities impacted by the downturn of the coal industry. In February 2016, the Revitalizing the Economy of Coal Communities by Leveraging Local Activities and Investing More (commonly known as RECLAIM) Act (H.R. 4456), a bill consistent with the President's proposal sponsored by Congressman Hal Rogers, was introduced in the House and gained a bipartisan group of 27 co-sponsors by the end of the 114th Congress.

Coal Power Plant Closures

From 2011 to 2015, 345 coal-fired generators were shut down and 20 were added, resulting in a loss of 33 gigawatts, or 10 percent, of the 2011 coal-fired generating capacity.[j, k] The number of power plants reporting coal as their primary fuel source dropped from 589 to 427.[l] Not all of these numbers represent closures of entire plants; many plants have multiple generating units, and some units have been switched to natural gas rather than shut down, retaining much of their workforce. Nevertheless, fossil fuel electric power generation employment fell 5 percent from 2011–2015.[m] The loss of power plant jobs in rural communities can have effects similar to those described above for coal mining job losses.

Several factors help mitigate, though not eliminate, the effects of coal-fired power plant job losses.[n, o] For example, in 2012, American Electric Power began planning for plant closures affecting 570 jobs that would occur by 2016. As closures occurred, almost half of the employees moved to positions at other plants. Some retraining occurred, but many employees received similar jobs. Other positions remained vacant after normal retirements, and many employees were retirement eligible at the time of closure due to the advanced age of the workforce.[p] These closures still affected workers and communities, but the utility's planning efforts lessened the effect.

[j] Energy Information Administration (EIA), *Electric Power Annual* 2015 (Washington, DC: EIA, November 2016), Table 4.6, http://www.eia.gov/electricity/annual/.

[k] Energy Information Administration (EIA), *Electric Power Annual* 2015 (Washington, DC: EIA, November 2016), Table 4.3, http://www.eia.gov/electricity/annual/.

[l] Energy Information Administration (EIA), *Electric Power Annual* 2015 (Washington, DC: EIA, November 2016), Table 4.1, http://www.eia.gov/electricity/annual/.

[m] Department of Labor, "Quarterly Census of Employment and Wages," Bureau of Labor Statistics, NAICS 221112, accessed November 21, 2016, http://www.bls.gov/data.

[n] Edward Louie and Joshua Pearce, *Retraining Investment for U.S. Transition from Coal to Solar Photovoltaic Employment* (Michigan: Michigan Technological University, 2016).

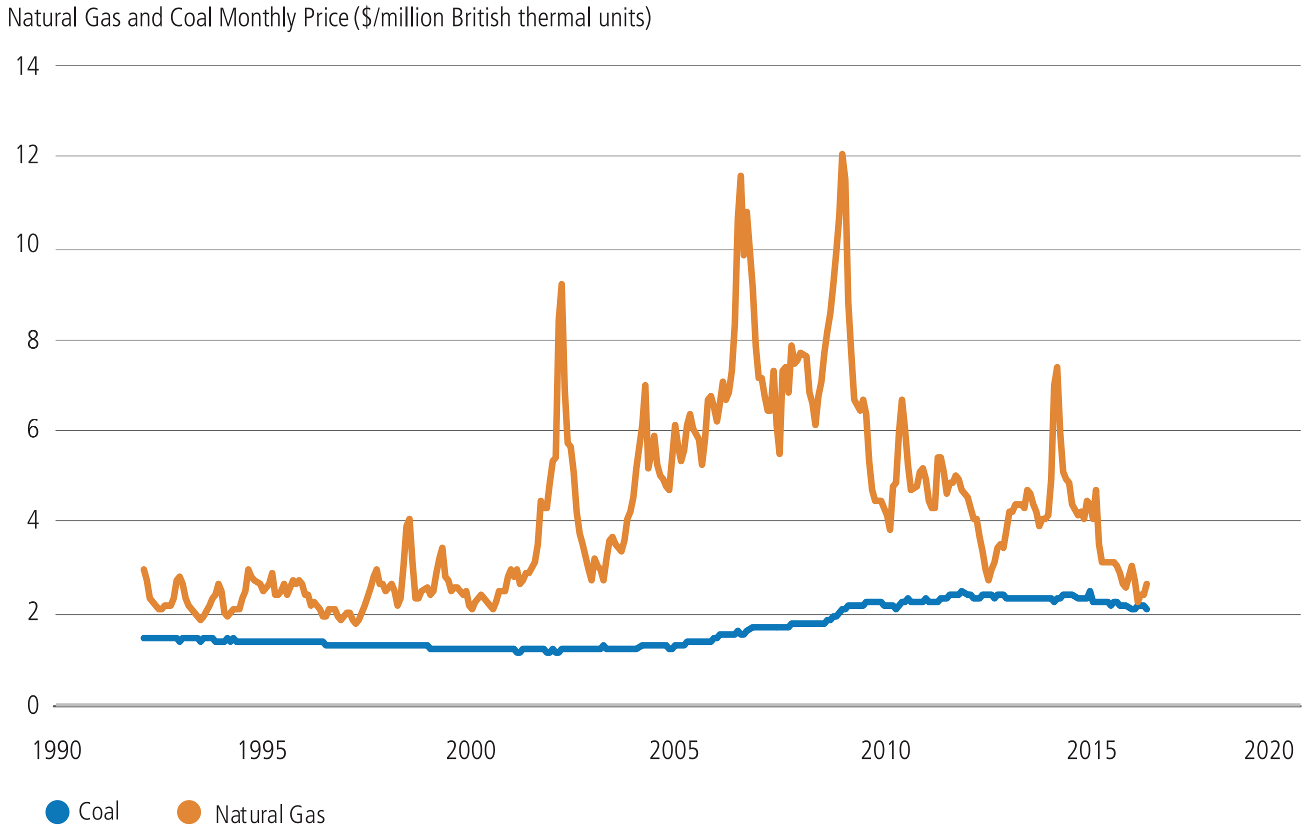
[o] Lee Buchsbaum, "Supporting Coal Power Plant Workers through Plant Closures," *Power*, June 1, 2016, http://www.powermag.com/supporting-coal-power-plant-workers-plant-closures/?pagenum=1.

[p] Lee Buchsbaum, "Supporting Coal Power Plant Workers through Plant Closures," *Power*, June 1, 2016, http://www.powermag.com/supporting-coal-power-plant-workers-plant-closures/?pagenum=1.

Natural Gas Employment Trends Reflect Shale Boom

Beginning around 2009, the influx of new supply from unconventional sources reduced natural gas prices to pre-2000 low price levels (Figure 5-9).[93] Low prices relative to coal increased demand for natural gas from the electric power system—now the largest consumer of natural gas in the United States. From 2008 to 2015, electricity generation from natural gas rose 51 percent.[94]

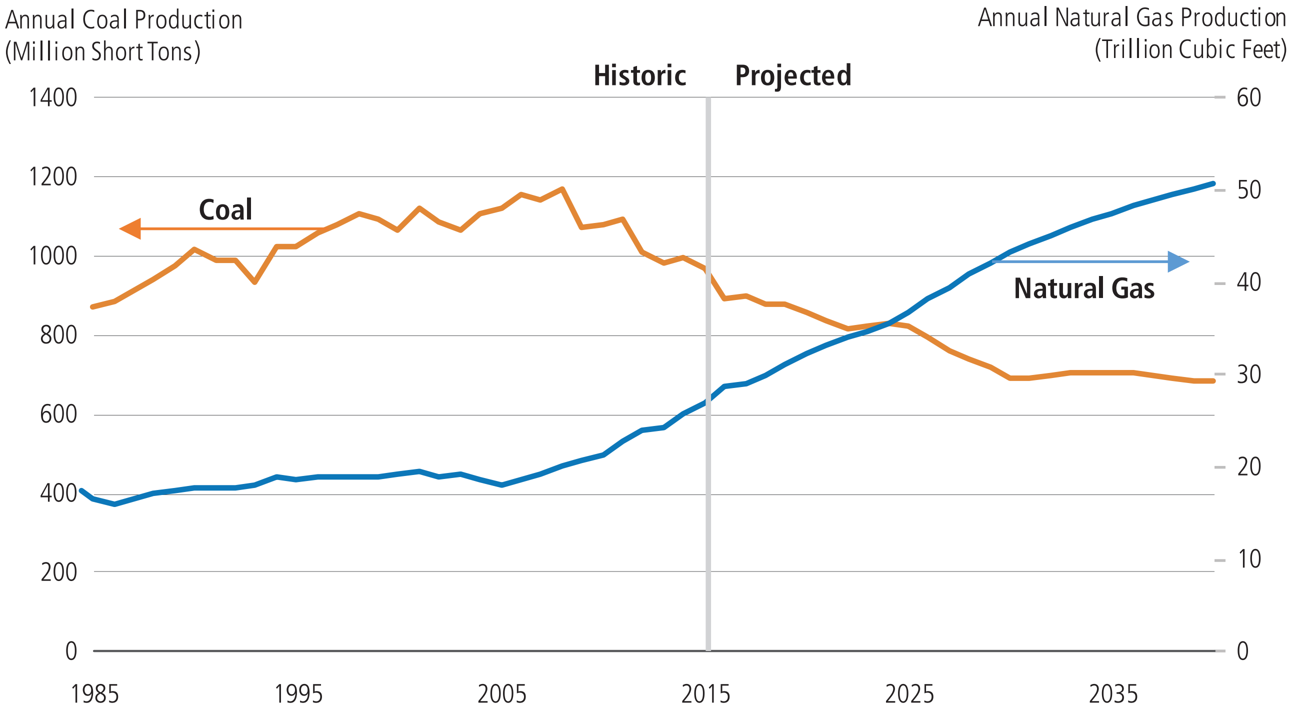
Figure 5-9. Average Monthly Cost of Delivered Fossil Fuels in the U.S. Electricity Industry, 1993–2015[95]



Natural gas prices fell back to pre-2000 prices around 2008. This price drop and increase in the price of coal has made natural gas more competitive than coal in many regions of the country.

The changing relative prices of natural gas and coal and the subsequent change in generation mix led to a large net increase in jobs over the last decade. The natural gas and oil extraction industry added about 80,000 jobs from 2004 to 2014.[96] When support activities, pipeline construction, and associated machinery construction are included, this number increases to about 400,000.[97] Recently, natural gas and oil extraction employment has declined by around 25,000 jobs between early 2015 through November 2016.[98] However, unlike coal production, natural gas production is projected to increase over the coming decades, sustaining natural gas industry employment (Figure 5-10).[99, 100]

Figure 5-10. Historic and Projected Annual Coal and Natural Gas Production, 1985–2040[101, 102, 103]



Coal production is projected to decline in the coming years in the business-as-usual scenario shown here, while natural gas production is forecast to increase substantially. These changes imply the employment prospects within these two industries. Though the oil and gas industry has lost a substantial number of jobs in 2015 and 2016, the industry is forecast to increase production in the long term.

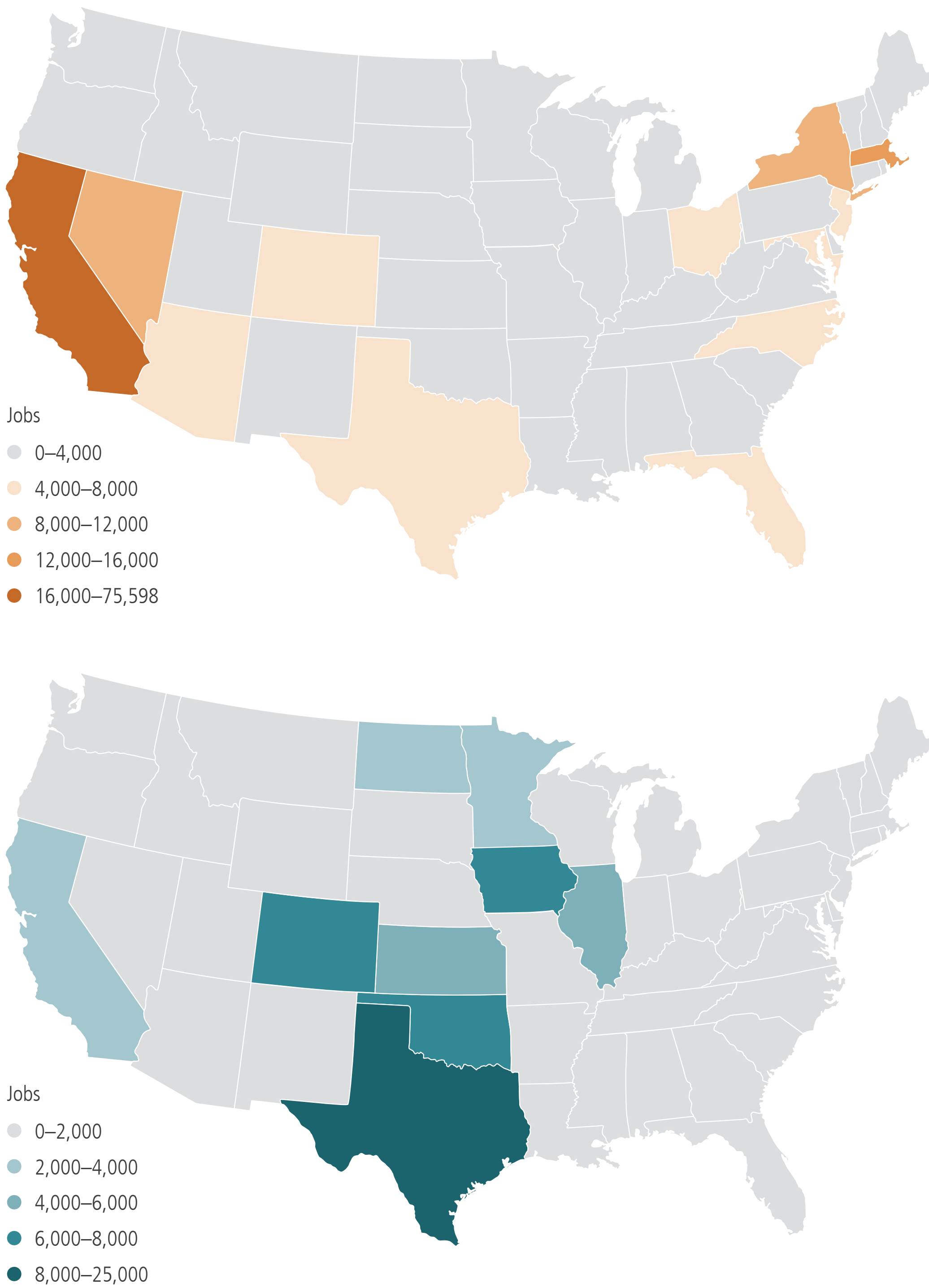
Despite potential employment growth from the expected increase in natural gas production in the coming years, jobs in the natural gas industry pose several workforce challenges. As revealed by the recent shale boom, jobs in the oil and natural gas production industry shift location regularly—posing challenges for employees and the economies of the areas where they live and work.[104] Rapid influx of workers can strain local housing availability, and subsequent outflows of workers can leave partially constructed housing in its wake.[105] While average incomes in oil and gas extraction are high (Table 5-1), job security is low, as the industry fluctuates in response to global markets and as extraction regions experience boom and bust cycles.[106] These rapid transitions are characteristic of the oil and natural gas industry, while changes in the coal industry have played out over longer periods.

Sector Employment in Renewable Energy Continues to Grow

In 2016, the traditional energy sector employed approximately 4.1 million workers. Of these, electric power generation and fuels technologies directly employed more than 1.9 million workers. And, job growth in the renewable energy industry remains strong. Wind power constituted the largest portion of generation capacity additions in 2015.[107] Employment in the solar industry has grown over 20 percent annually from 2013 to 2015. From 2010 to 2015, the solar industry created 115,000 new jobs. In 2016, just under 375,000 individuals worked, in whole or in part, for solar firms, with more than 260,000 of those employees spending most of their time on solar. There were an additional 108,000 workers employed at wind firms across the Nation. The solar workforce increased by 25 percent in 2016, while wind employment increased by 32 percent.[108] Of the 375,000 individuals working in solar, nearly half of these are in the solar installation industry, requiring distinct skillsets compared to traditional generation technologies. Solar industry jobs are relatively high paying compared to all jobs nationally, with a significant range of earnings across occupations within the industry.

Currently, renewable energy jobs are geographically concentrated according to high-value wind and solar resources and state-specific renewable portfolio standards; over half of all the solar jobs in the United States are found in only four states (Figure 5-11).[109]

Figure 5-11. Distribution of Solar Industry Jobs (top) and Wind Industry Jobs (bottom) by State, 2015[110, 111]



Solar industry jobs are primarily located on the coasts, while wind industry jobs are prevalent in the central United States. Together, wind and solar employment cover much of the United States. Job locations are driven by resource availability and by state policies.

Coal, Natural Gas, and Renewable Energy Shifts Create a Mismatch in Electricity System Job Opportunities

While there is potential for long-term job growth in renewable energy and natural gas extraction and further declines in coal mining, these jobs are not substitutable. Several factors prevent employment opportunities in the renewables and natural gas industries from reaching those communities most affected by erosion of job opportunities:

- **The geographic locations of electricity sector job losses and gains are currently not well correlated.**

  Job losses from the coal mining industry are largely concentrated in southern Appalachia, while growth in natural gas extraction and the renewable energy industry is located elsewhere.

- **Income discrepancies between industries is a challenge for reemployment.**

  The median wage for solar installers is higher than the median wage across all occupations. It remains more than 20 percent less than the median wage for coal mining jobs,[112] and U.S. solar manufacturing jobs generally pay 10 percent less than U.S. manufacturing jobs.[113] While there is an income discrepancy between coal and solar jobs, solar jobs are rapidly increasing. Retraining and creating more localized solar jobs is important.

- **The skills required for employment vary between industries experiencing growth and those experiencing decline.**

  Natural gas and coal jobs are largely extraction focused; whereas, wind and solar energy jobs are significantly manufacturing based (almost 50 percent for wind and 40 percent for solar) and construction based (20 percent for wind and almost 30 percent for solar).[114] Significant retraining would be required to transition between these jobs.

Employment in the Nuclear Industry

The "U.S. Energy and Employment Report" finds that 68,000 people are employed in the nuclear generation industry.[q] Employment in the industry may fall as nuclear power plants retire. Since 2013, six nuclear reactors have shut down prior to the end of their existing licenses. Another 10 reactors have made closure announcements to cease operation over the next 10 years; 8 will close before the end of their current operating licenses. Recent state actions, pending any legal challenges, may enable four of those to continue operating. However, the net employment impact of plant closures may be mitigated through employee retirements and transfers to other power generation facilities.[r]

Construction of nuclear power plants requires thousands of skilled construction workers.[s] To ensure an adequate supply of highly trained workers for the construction of nuclear reactor units at Plant Vogtle in Georgia, North America's Building Trades Unions and Georgia Power created an apprenticeship-readiness training program under the Helmets to Hardhats initiative. The program focuses on increasing workforce inclusiveness and providing job opportunities to veterans.[t]

Employment in uranium production (mining, milling, and processing) has trended with production levels. Though employment numbers are unknown prior to 1993, uranium production over the last two decades was a fraction of average annual production from 1960 to the early 1980s.[u] The uranium production industry employed 625 people in 2015, down from a 21st-century peak of 1,563 in 2008.[v]

Employment trends in the uranium industry closely mirror resource prices; these have fallen from a peak of over $100 per pound of triuranium octoxide (U3O8) in 2007 to below $30 in 2015. Prices are anticipated to remain low due to growing inventories owned by nuclear power owners and operators. Total inventories in 2015 were enough to fuel 2 years of nuclear power production at use-rate averages over the last decade.[w]

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q BW Research, *U.S. Energy and Employment Report* (Washington, DC: Department of Energy, January 2017).

r Elizabeth McAndrew-Benavides, "NEI's 2015 Nuclear Workforce Survey" (presented on behalf of the Nuclear Energy Institute, October 2015), https://www.nei.org/CorporateSite/media/filefolder/Backgrounders/Presentations/NEI-s-2015-Nuclear-Workforce-Survey-Presentation-to-the-NRC-October-2015.pdf?ext=.pdf.

s "Nuclear Job Opportunities, Plant Vogtle Units 3 & 4," Georgia Power, accessed November 21, 2016, https://www.georgiapower.com/about-energy/energy-sources/nuclear/jobs.cshtml.

t "Building Trades Apprenticeship-Readiness Program," Commercial Construction & Renovation, accessed November 21, 2016, http://www.ccr-mag.com/augusta-building-trades-apprenticeship-readiness-program/.

u Doug Bonnar, "U.S. Uranium Production Is Near Historic Low as Imports Continue to Fuel U.S. Reactors," *Today in Energy*, Energy Information Administration, June 1, 2016, http://www.eia.gov/todayinenergy/detail.php?id=26472.

v Energy Information Administration (EIA), *2015 Domestic Uranium Production Report* (Washington, DC: EIA, May 2016), https://www.eia.gov/uranium/production/annual/pdf/dupr.pdf.

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How Government and Industry Can Respond to Recent Changes

The broader changes in the electricity industry have created both new opportunities and new challenges for the electricity industry workforce. Opportunities include new workforce potential in the renewable energy industry and ICT; challenges include the skills gap for deploying and operating new technologies, the shift in the geographic location of jobs, and the need to recruit and retain an inclusive workforce. The government working with industry could help provide skills training, workforce data, and support for communities experiencing economic dislocation.

Skills Training and Workforce Development

Companies, industry representatives, and labor unions have pursued a variety of skills training and workforce development programs to overcome workforce skills deficiencies.

Many utilities operate their own line worker schools, joint labor management apprenticeship programs, and other training programs, while others recruit from line worker training schools that offer introductory programs.[115] Additional programs include a uniform nuclear curriculum program and a power plant technology program.[116] In FY 2014, 7,253 apprentices were enrolled in registered apprenticeship programs for line installer/repairers, line maintainers, and line erectors.[117]

In 2006, the major industry trade associations and many leading companies formed the nonprofit Center for Energy Workforce Development (CEWD): "CEWD was formed to help utilities work together to develop solutions to the coming workforce shortage in the utility industry. It is the first partnership between utilities, their associations, contractors, and unions to focus on the need to build a skilled workforce pipeline that will meet future industry needs."[118] Today, CEWD includes the five major utility trade associations, the industry's two principal unions, and more than 100 companies that employ over 90 percent of utility workers. CEWD is organized through more than 30 state consortia that are focused on working with local educational institutions, their union apprenticeship programs, and other stakeholders to create a high-quality, diversified workforce.

Construction industry training programs are particularly important for energy efficiency. Nationally, North America's Building Trades Unions operate over 1,600 Joint Apprenticeship Training Committees (JATC) with their construction employers. These JATC's train 74 percent of all construction apprentices in the United States at a cost of $1.3 billion annually.[119]

As the electricity industry relies increasingly on ICT components in creating a smart grid, the labor intensity of the electricity grid of the 21st century may decrease. Critically important industries that face similar challenges have already used redesigned work processes and innovative workforce practices to increase efficiency. The increased use of technology—for example smart meters to reduce the need for meter readers, smart grid components that isolate faults and reduce outages, or aerial inspection technology to improve damage assessments—might also increase workforce efficiency.

Smart Grid Workforce Training and Development under the American Recovery and Reinvestment Act of 2009

In 2010, the Department of Energy awarded nearly $100 million of funding appropriated under the American Recovery and Reinvestment Act of 2009 to support 54 workforce training programs in the utility and electrical manufacturing industries. Funding for these programs was cost-shared with community colleges, universities, utilities, and manufacturers, and it is estimated to have trained approximately 30,000 people.[x]

[x] "Obama Administration Announces Nearly $100 Million for Smart Grid Workforce Training and Development," Department of Energy, April 8, 2010, http://energy.gov/articles/obama-administration-announces-nearly-100-million-smart-grid-workforce-training-and.

Electricity System Workforce Outreach and Inclusion Programs

In addition to government programs, private partnerships with nonprofit organizations are also focused on increasing the inclusiveness of the energy sector workforce. GRID Alternatives, together with SunEdison, created the Realizing an Inclusive Solar Economy Initiative, which focuses on recruiting members of underrepresented communities for jobs in the solar industry—providing solar installation training, working with the solar industry to identify needed skills for the trainings, linking trained candidates with available employers, and ensuring the retention of a diverse workforce in the industry.[120]

Additional targeted initiatives include the Utility Industry Workforce Initiative, where CEWD joined with the Departments of Energy, Labor, Defense, and Veterans Affairs; the International Brotherhood of Electrical Workers; and the Utility Workers Union of America to increase hiring rates of veterans in the industry.[121] Helmets to Hardhats, run by the North American Building Trades Unions, also trains veterans for the construction and utility industries.[122]

Department of Energy Workforce Inclusion Programs

Several outreach programs have been established to build a more inclusive work environment in the energy sector. The Department of Energy (DOE) launched the Minorities in Energy Initiative in 2013 to "strive to ensure that our energy workforce more fully reflects the diversity and strengths of the country."[y] DOE, through the National Nuclear Security Agency, also sponsors the Minority Serving Institutes Partnership Program and the Cybersecurity Consortium at Historically Black Colleges and Universities.[z] In 2014, DOE also created the Solar Ready Vets® program through its SunShot Initiative.[aa] The program trains exiting service members to become solar installers and, through the Department of Defense SkillBridge program, has developed a program that provides on-base training during the last six months of service. Other programs are more broadly focused on improving participation among women and minorities in science, technology, engineering, and mathematics (STEM) fields and career pathways. Specific DOE initiatives for STEM outreach include the Clean Energy Education & Empowerment initiative and the Mickey Leland Energy Fellowship Program.[ab]

[y] "Introducing the Minorities in Energy Initiative," Department of Energy, accessed December 12, 2016, http://energy.gov/articles/introducing-minorities-energy-initiative.

[z] Carenda L Martin, "Labs Team Up with Historically Black Colleges and Universities in Cybersecurity Consortium," Lawrence Livermore National Laboratory, January 23, 2015, https://www.llnl.gov/news/labs-team-historically-black-colleges-and-universities-cybersecurity-consortium.

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Federal Workforce Data and Coordinated Programs

In response to the lack of high-quality and discrete energy jobs data, the Department of Energy launched the Jobs Strategy Council, which commissioned USEER, making significant strides in improving the availability of data and insights for the energy and electricity industry workforce.[123] The second edition of the report will provide more precise job categorization—particularly for natural gas industry employment estimates—and will be published in January 2017.

Title X of H.R. 6, the 2007 Energy Bill, established the Energy Efficiency and Renewable Energy Worker Training program for the Department of Labor to administer.[124] In addition to the training program, H.R. 6 required the Secretary of Labor to collect and analyze labor market data to track energy-related workforce trends, award competitive National Energy Training Partnerships Grants to implement training for economic self-sufficiency, and develop an energy efficiency and renewable energy industries workforce. Finally, the Secretary of Labor was required to award competitive grants to states to administer labor market research, information, and labor exchange research programs, as well as renewable energy and energy efficiency workforce development programs.[125] To date, this program remains unfunded by Congress.

Support for Communities Experiencing Economic Dislocation

The United States has a long history of providing adjustment and training programs to workers in industries undergoing transition. The Trade Adjustment Assistance program for workers in trade-exposed industries with increased import competition was established in 1962, and the broader Job Training Partnership Act was passed in 1982.[126] The Clean Air Employment Transition Assistance Program, included in the Clean Air Act Amendments of 1990 and subsequently repealed, provided training, adjustment assistance, employment services, and needs-related payments to workers who lost jobs due to a business's compliance with the Clean Air Act.[127, 128] Current changes in the electricity sector are rapid and significant; targeted assistance may aid in addressing this transition. An alternative approach for older workers in regions with few economic opportunities could also provide a financial bridge to retirement in areas of rapid transition.

ARC is a regional economic development agency created in 1965 to help the Appalachian region reach socioeconomic parity with the rest of the Nation. ARC funds business development, workforce development, infrastructure investment, and community capacity building through Federal appropriations. Despite ongoing economic challenges in the region, ARC's non-highway appropriated budget has fallen from roughly $600 million in the early 1970s to below $100 million in the 1980s. Its budget has averaged below $100 million per year until 2016 when it grew to $146 million.[129, 130]

The continued fiscal difficulties of coal miner pensions threaten the solvency of PBGC. Ensuring the continued fiscal health of PBGC would support retired workers and their spouses and provide sources of economic wealth in communities with decreasing sources of local government revenues.

While local governments experience losses in tax revenue, it is essential to ensure that children have access to adequate education. The Federal Government previously assisted in similar situations through the now-expired Department of Agriculture Secure Rural Schools (SRS) program, which provided grants to schools in communities that were suffering from the precipitous decline in logging on Federal land in the 1990s.[131] In FY 2015, the SRS program paid $222 million to localities in 41 states and Puerto Rico to invest in school systems and road infrastructure.[132, 133] The amount of support required in coal communities is likely significantly less than in the SRS program, which reached 9 million children.[134] All of the central Appalachian states spend within 10 percent of the U.S. average of $10,600 per student per year, and fewer than 100,000 students live in counties where at least 1 percent of the population works in coal mining.[135, 136, 137]

The AML Fund's inability to fully support reclamation of lands disrupted by the coal mining industry has the potential to leave communities in regions with declining local revenues with polluted and unsafe lands and few means to repair the damage. Ensuring funding and appropriate design for the AML Fund will help prevent mines that were once a source of prosperity for these communities from becoming sources of sustained financial and community health challenges.

The Partnership for Opportunity and Workforce Economic Revitalization (POWER) Initiative

The POWER Initiative is a coordinated Federal effort designed to assist communities that are negatively impacted by changes in the coal and electricity industries by funding investments in economic revitalization and workforce training in coal communities across the United States. The Appalachian Regional Commission and the Department of Commerce's Economic Development Administration administer the program.[ac] Several first and second round grantees provide workforce development and training opportunities for workers displaced by the contraction of the coal industry in addition to economic development planning assistance.[ad]

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The recommendations based on the analysis in this chapter are covered in Chapter VII (*A 21st-Century Electricity System: Conclusions and Recommendations*).

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Chapter VI

ENHANCING ELECTRICITY INTEGRATION IN NORTH AMERICA

This chapter details the interconnectivity of the United States', Canada's, and Mexico's electricity systems, as well as opportunities for enhancing integration.[a] First, the chapter outlines the existing consensus between the nations to improve integration and the regional variation in transmission capacity that exists. The next two sections explore the integration of the United States with Canada and Mexico, respectively, and provide in-depth discussions of relevant country-specific policies. The chapter concludes with possible policy options to improve integration, as well as ongoing and potential opportunities for collaboration.

[a] Due to the nature of electricity system interconnections and for simplicity of terminology, the term "North America" will be used in this chapter to refer narrowly to the continental United States, Canada, and Mexico.

FINDINGS IN BRIEF:
Enhancing Electricity Integration in North America

- Integration of the Canadian, Mexican, and U.S. power systems historically occurred by gradual, ad-hoc, and regional adjustments implemented by an array of regional, public, and private stakeholders, reflecting the complex and fragmented jurisdictions in all countries. Many opportunities for enhanced integration have included a collection of stakeholders and were pursued on a subregional basis.
- One model for power sector collaboration across national borders is demonstrated by the reliability planning under the North American Electric Reliability Corporation; however, this engagement has been limited to Canada, the United States, and the Baja California region of Mexico. The Canadian, Mexican, and U.S. governments have all made significant climate commitments and have indicated a desire to shift toward greater renewable energy penetration. In June 2016, the United States, Canada, and Mexico announced a goal for North America to strive to achieve 50 percent clean power generation by 2025. Greater cross-border integration could be a tool to maximize gains from the deployment of clean energy generation and energy efficiency, but the complexity and current asymmetry of national and subnational policy frameworks may impede implementation.
- The design of domestic U.S. clean energy policies, both at the Federal and state level, has implications for cross-border trade and continental emissions reductions. Currently, there are significant disparities between U.S. states' policies for recognition or exclusion of international clean energy imports.
- Continued study of the context and levels of integration of each subregional, cross-border interconnection will allow for a deeper understanding of policies that have shaped current levels of cross-border trade (Table 6-1).
- Canada has additional hydropower resources that could be exported to the United States to provide a reliable source of firm, low-carbon energy. There are concerns among stakeholders that increased imports of Canadian hydropower could reduce U.S. clean energy competitiveness; however, there are examples of arrangements where Canadian hydropower decreases curtailments of U.S. clean resources.
- Trade has been increasing across the North American bulk power system, but cross-border flows, especially between Canada and the United States, are now using the full capacity of existing transmission infrastructure.
- Under a low-carbon future scenario, current modeling results show that transmission with Canada becomes increasingly important for sustaining emissions reductions and has a significant impact on the generation mix in border regions.
- While many electricity system models exist for the United States (and in some cases, the United States and Canada), detailed modeling tools to explore the economic, social, and/or reliability impacts of electricity trade across all of North America are currently insufficient to inform opportunities for enhancing integration.
- While extensive integration between the United States and Canada can inform the potential for increased future U.S.-Mexico integration, these situations are fundamentally dissimilar in four main ways: (1) the lack of a dominant exporting country on the U.S.-Mexican border, (2) the different regional approaches to integration on the U.S. side, (3) the nascent regulatory framework in Mexico, and (4) the differing legal instruments for open-access transmission agreements and reliability coordination between the United States and Mexico.
- Mexico's ongoing electric utility industry reforms could have significant impacts on the future of cross-border integration. The reforms are focused on the overall goal of competitiveness, with the twin objectives of reducing electricity costs and developing more clean energy. A transition in Mexico from oil to natural gas in electricity generation could have tremendous impacts on the manufacturing sector, reducing electricity prices, boosting manufacturing output, and increasing overall gross domestic product for Mexico.

FINDINGS IN BRIEF:
Enhancing Electricity Integration in North America (continued)

- Mexico's increasing importation of U.S. natural gas could be an economic and environmental opportunity for both sides by offsetting expensive and high greenhouse gas–emitting diesel generation in Mexico and creating economic opportunities for U.S. exporters. The resulting reduction in electricity costs in Mexico could also boost overall North American competitiveness.
- The Electric Reliability Council of Texas could benefit from greater integration with Mexico through access to enhanced imports, or as a business opportunity for power exporters.
- California's ambitious clean energy policy provides an opportunity for energy exporters in Mexico, especially in the Baja California region, to supply clean energy, dispatchable power, or essential reliability services.

Cross-Border Electricity Integration

The potential for electricity integration to provide economic benefits and support the development of more modern and resilient energy infrastructure has been a long-standing theme for North American diplomacy.[1, 2] There is consensus between leaders of Mexico, Canada, and the United States that electricity integration brings great value to all three nations, but the details of planning and implementing electricity integration require the navigation of national, regional, and local interests through the engagement of a broad set of public and private stakeholders.[3]

Consensus to Enhance North American Electricity Integration

Leaders in the United States, Canada, and Mexico have publicly and repeatedly affirmed support for the concept of increasing energy integration,[4] and there is a general understanding across the continent that the benefits of cross-border electricity trade can be improved with deeper system integration. In June 2016, at the North American Leaders' Summit, President Barack Obama, President Enrique Peña Nieto, and Prime Minister Justin Trudeau signed a statement agreeing to collaborate on cross-border transmission projects in order to achieve the mutual goal of advancing clean and secure power. In particular, the United States, Canada, and Mexico announced a goal for North America to strive to achieve 50 percent clean power generation by 2025.

A number of additional recent developments make a discussion of cross-border electricity integration[b] especially relevant:

- The completion of transformational energy reforms in Mexico in the oil, gas, and electricity sectors.
- Canada's framework on clean growth and climate change, charting an accelerated path to achieve deep greenhouse gas (GHG) emissions reductions and green infrastructure development.
- The shale gas boom in the United States, which presents new opportunities for natural gas generation, as well as raises questions about land use and emissions.
- The Paris Agreement and the steps needed to implement nationally determined contributions globally.

[b] While the discussion of power sector integration has been of intense international interest, moving from aspirational objectives to actionable policy steps requires a clear, yet nuanced, definition of "integration" (or its close homologue, "harmonization"). While these terms are commonly discussed among a broad range of cross-border power sector stakeholders, there is no single definition for their use. For the purposes of this discussion, we define integration to include basic information sharing in policy making and planning, as well as the coordination of policies and decision making, often with the result of enhancing flows of cross-border trade. For the power sector, this includes any level of coordination in planning, system operations, or regulation.

- All three countries' sustained interest in stimulating strategic opportunities in clean energy development and energy efficiency.[5]
- The acceleration of the deployment of renewable energy technologies, which creates opportunities for grid management through integration.

Regional Variation in Integration across North America

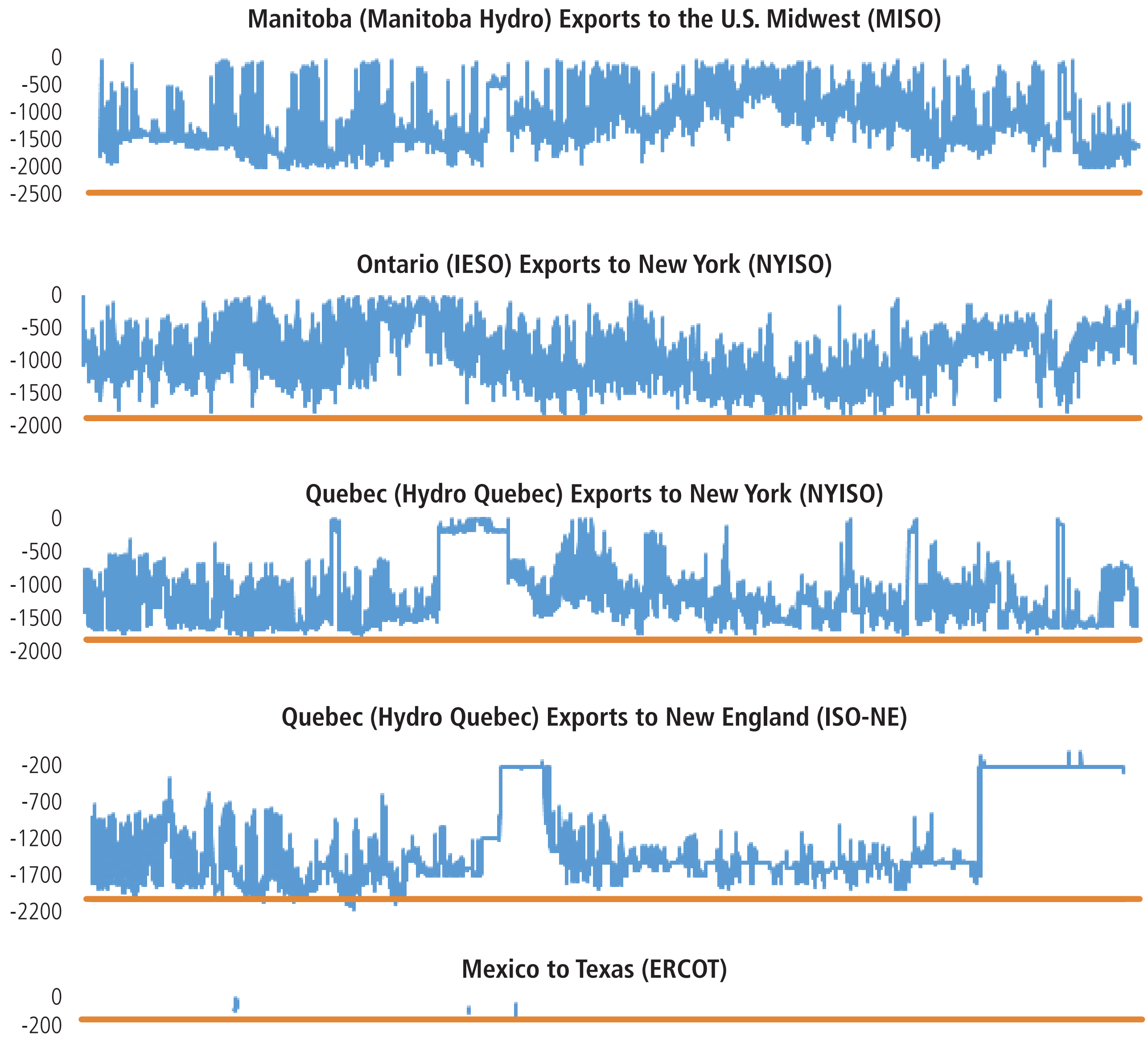
The North American electricity system is heterogeneous; operations and planning primarily take place through regional entities, and every part of the system has evolved with different characteristics and structures.[6] This leads to complex and asymmetrical jurisdictions and regulations, as well as cases in which international, cross-border coordination is sometimes greater than subregional coordination within a specific country. U.S.-Canadian integration is often greater than between Canadian provinces.[7]

A subregional lens is necessary to understand the contextual variety of the integration and interconnections between Canada and the U.S. Pacific Northwest, Midwest, and Northeast regions, as well Mexico and the southern border region with Arizona, California, New Mexico, and Texas. These different levels of integration range from physical, asynchronous interconnections geared toward emergency trade (such as in the Electric Reliability Council of Texas [ERCOT]-Mexico cross-border interactions) to extensive, synchronous interconnections that enable Canadian cross-border participation in U.S. competitive electricity markets (e.g., the Manitoba Hydro-Midcontinent Independent System Operator [ISO]). Because of this diversity, there are additional opportunities for enhanced integration that should be examined to maximize the benefits for the largest number of stakeholders for the least cost.

Additional cross-border transmission infrastructure with Canada, for example, is projected to lead to lower overall system costs in U.S. border regions, and it could enhance reliability, backstop variable renewable energy development, and enable lower overall emissions of U.S. power consumption.[8, 9] Greater cross-border planning of transmission and operations between the United States and Mexico could maximize efficiencies for commercial opportunities for U.S. generators to sell into a higher-priced market, while lowering the electricity costs paid by industrial consumers in Mexico.[10, 11] Additional electricity trading between Mexico and the United States could enhance long-term price stability and have impacts on other market factors. Coordination of the United States' and Mexico's clean energy incentives and programs, such as clean energy certificates, could lead to additional opportunities for clean energy research, development, and deployment, as well as reductions in carbon emissions.[12]

The barriers to deepening integration are also regionally nuanced. Increasing cross-border integration, especially increasing cross-border trade, raises important questions about the economic impacts of enhanced integration on domestic power generators and jobs; the reliability of power supply; the environment; costs for consumers; and increased reliance on international sources of power. In most border regions, increasing electricity flows would require the construction of additional transmission infrastructure (Figure 6-1) since current lines between the United States and Canada are operating at or near capacity, and the connections between the United States and Mexico tend to have low capacity. Developers of new infrastructure will need to strategically align planning across borders in order to overcome opposition.

Figure 6-1. Transmission Capacity and Electricity Trade across Major Interconnections, June 2015–May 2016



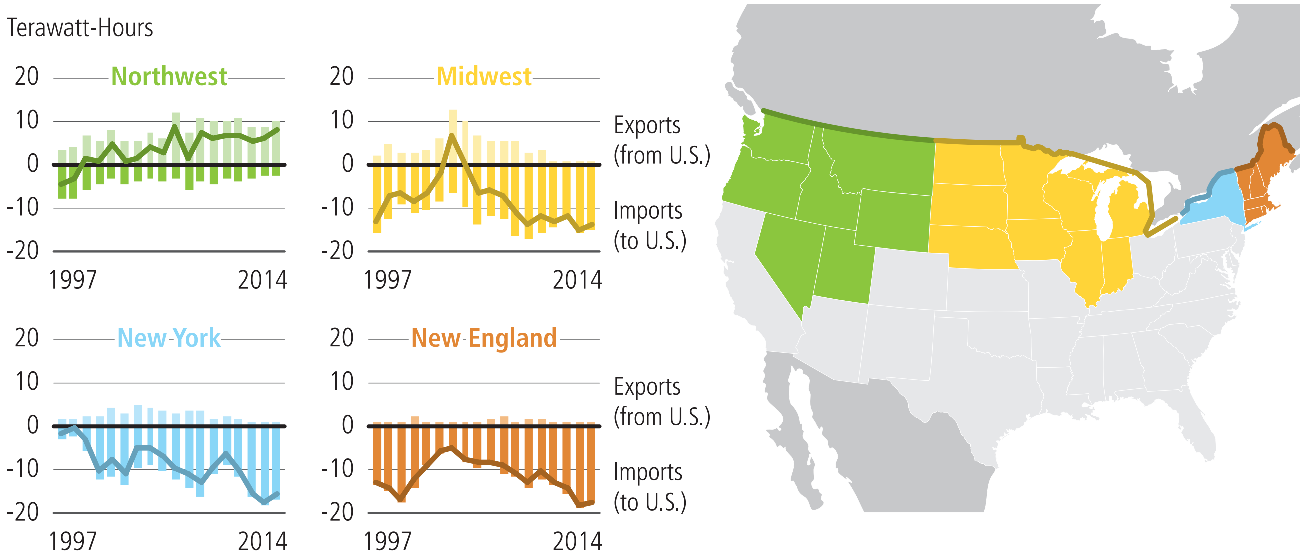
Blue lines show hourly export data from Canada and Mexico to the United States in negative megawatt-hours; orange lines indicate maximum export capacity, recorded hourly from June 9, 2015, to May 19, 2016. As the blue lines reach the orange limit of maximum capacity, transmission in that region is full and cannot be expanded on current lines. The proximity of hourly export flows to the maximum export capacity suggests that transmission lines are often fully utilized, especially in the northeastern United States. Flat-lined regions in Hydro Quebec figures are attributed to maintenance outages.

Acronyms: Midcontinent Independent System Operator (MISO), Independent Electricity System Operator (IESO), New York Independent System Operator (NYISO), Independent System Operator New England (ISO-NE), Electric Reliability Council of Texas (ERCOT).

U.S.-Canada Integration

The United States and Canada serve as a global model of highly functional, cross-border electricity coordination. Cross-border electricity trade and coordination of operations, policy, and regulatory planning are extensive, mature, and efficient, and they have led to economic and reliability benefits on both sides of the border.[13] Significant levels of cross-border transmission interconnect both countries, and electricity trade has been growing overall since 2005, increasingly dominated by flows from Canada to the United States.[14, 15] Total U.S.-Canada trade (including flows in both directions) in 2015 was 77 million megawatt-hours (MWh), accounting for a total of U.S. dollars (USD) $2.6 billion in revenues (Canadian dollars $3.4 billion).[16] With the notable exception of trade in the Pacific Northwest, which continues to be bidirectional (with the United States acting as a net exporter to Canada since 1999), in all other regions Canadian exports to the United States have significantly overtaken flows in the opposite direction (Figure 6-2).[17]

Figure 6-2. Overall U.S. Electricity Trade with Canada in Four Regions[18]



The graphs show U.S. electricity trade with Canada (1997–2014) in the Northwest, Midwest, New York, and New England. While the Pacific Northwest has been steadily increasing electricity exports to Canada, the Midwest, New York, and New England have been increasing imports over time.

Historical Overview

Recent trends in U.S.-Canada electricity trade reinforce a longer historical trajectory. Since the first electricity developments led to trade between the two countries in the early 1900s, private Canadian hydropower generators have prioritized exports to the United States over pan-Canadian trade due to a number of factors.[19] In accordance with Section 92A of the Canadian Constitutions Act of 1867, Canadian provinces have near-complete authority over their individual electricity systems. Many hydropower-producing provinces (such as British Columbia and Quebec) have vertically integrated utilities with regulated pricing structures. Markets with more diversified generation mixes (such as Ontario and Alberta), however, have implemented varying levels of restructuring, resulting in a system in which neighboring provinces often host asymmetrical market structures that aren't conducive to trade.[20] Transmission infrastructure development is determined by Canada's spatial population distribution: 75 percent of the Canadian population lives within 100 miles of the U.S. border and is clustered along the coasts.[21] Canadian hydropower producers—who have the greatest potential to increase capacity to serve other loads—have focused on extending transmission the short distances from Canadian population centers to the U.S. border rather than on more costly east-west transmission to other provinces.[c, 22]

[c] The Maritime Link Project, which links New Foundland, Labrador, and Nova Scotia, as well as discussions about exporting hydropower from British Columbia Hydro's Site C Clean Energy Project to Alberta, suggest this might be changing.

The high level of north-south integration between Canada and the United States, guided by jurisdictional, population, and geographic factors, means that cross-border coordination often surpasses east-west coordination among provinces, states, or ISOs within either country.[23] Primary interconnections link single Canadian provinces to markets in the United States: the Pacific Northwest to British Columbia; Manitoba to Midcontinent ISO; Ontario and Quebec to New York ISO; and Quebec to ISO New England.

These high levels of integration between the United States and Canada exist across the border and are facilitated in a variety of ways. For example, since 1964 the Columbia River Treaty has contributed substantially to the economic progress and safety of both countries through coordinated flood-risk management and clean, renewable hydropower within the Columbia River Basin in the Pacific Northwest. Ongoing negotiations on a new formal treaty with Canada to extend this arrangement beyond 2024 are critically important to the economy of the Pacific Northwest region, particularly for flood management and hydropower optimization.

The significant level of integration between the United States and Canada also has reliability implications. Two large-scale, cross-border blackouts—the Great Northeast Blackout of 1965 and the Northeast Blackout of 2003—among other factors, significantly shaped the current policies regarding reliability. Those events played a role in spurring the subsequent establishment of the North American Electric Reliability Corporation (NERC), the Energy Policy Act of 1992, and the Federal Energy Regulatory Commission (FERC) orders to open transmission access.[24] See the Appendix (*Electricity System Overview*) for additional detail on these events.

Benefits and Barriers to Increasing Cross-Border Electricity Trade

There is high potential to increase Canadian hydropower exports to the United States. The Canadian Hydropower Association estimates that Canada has a technical hydropower-generation potential that could more than triple current levels, up to 236 gigawatts.[25] As a resource, hydropower has several advantages: it is flexible, reliable, and cost-competitive with other sources of power, and it produces nearly zero carbon emissions.[26, 27] Hydro reservoirs can provide energy storage, and hydropower generation can be adjusted relatively quickly, making it a natural complement to intermittent resources such as solar and wind power.[28] Some dams also serve additional functions, such as managing flood control or storing potable water. Already, the climate and energy security benefits of Canadian-U.S. hydropower trade may be substantial. By one estimate, trade in hydropower between Quebec and its neighbors (New England, New York, Ontario, and New Brunswick) can be credited with 20.6 megatonnes of avoided emissions from 2006–2008.[29]

Electricity imports can serve as a cost-effective supply for wholesale power markets in the United States. The External Market Monitor of ISO New England concluded that importing electricity from Quebec and New Brunswick "reduces wholesale power costs for electricity consumers in New England."[30] Similarly, a New England States Committee on Electricity study on incremental hydroelectric imports from Canada found average annual economic benefits associated with reduced electricity prices in New England to be in the range of USD $103 million to $471 million.[31]

Cross-border trade between the United States and Canada is mature and highly integrated, but enhancing integration—especially with the objective of increasing cross-border trade—faces interrelated barriers. First, there are concerns from generators within the United States that increasing cross-border trade would have a negative impact on domestic markets and give Canadian suppliers market power.[32] In the 2000s, Canadian hydropower was viewed as one of the most cost-effective electricity sources, which presented a double-edged sword: it could lower prices for U.S. customers, but it could also outcompete U.S. generators in the natural gas and renewable energy sectors. In recent years, low U.S. natural gas prices have shifted the business case for increasing cross-border trade by reducing the extent to which imports from Canada would lower costs for electricity users.[d, 33] Continued, thorough examination of the long-term implications of integration for consumers and generators will be needed in the future.

Second, increasing electricity trade would require additional transmission capacity. While several transmission projects have already been proposed to increase capacity in the Midwest and Northeast, the complexity of these projects raises a variety of stakeholder concerns that lead to long development times and unexpected delays.[34] Concerns range from the environmental impacts of transmission infrastructure to the potential implications of greater Canadian imports on local and regional economic development.

Siting and permitting decisions are made at the state and local level, including for international transmission lines. Continued integration and transformation of the North American electricity system requires effective siting and permitting capabilities at all levels of government. Planning and permitting new cross-border transmission infrastructure, including managing ecological impacts across jurisdictions and with a wide range of domestic and international stakeholders, is uniquely challenging. State, provincial, local, and tribal governments, assisted by Federal agencies, need to build capacity to minimize safety and security consequences and protect the environment, while limiting permitting-related delays.[35, 36] Government efforts at the Federal and local levels should ensure that project developers have a clear understanding of expectations, best practices, and priorities during the permitting of cross-border transmission projects. The issuance of recent cross-border Presidential permits for the Great Northern Transmission Line[37] in Minnesota and the New England Clean Power Link[38] in Vermont are both examples of the application of collaborative principles of early engagement with stakeholders detailed in the new Integrated Interagency Pre-Application Process.[39] Additional study of and updated information on cross-border regulation can assist with establishing a clear understanding of requirements at the Federal and state levels for the permitting of cross-border transmission facilities.

Clean Electricity Development in the Cross-Border Context

Analysis of the economic and environmental impacts of increased levels of hydroelectric imports from Canada indicates that the potential for cumulative reductions in GHG emissions range from 58 million to 97 million megatonnes.[40] Many U.S states have established renewable portfolio standards (RPS), not only to reduce GHG emissions, but also to stimulate local development of clean electricity. Concerns about the negative environmental impacts of large-scale hydropower have led a number of states to adopt RPS that exclude large-scale hydropower, leading to a "non-counting" of Canadian hydropower, regardless of the positive impact such imports would have on the state's emissions. Currently, Minnesota, Vermont, and Wisconsin are the only U.S. northern border states that have RPS that allow for the accounting of some forms of large-scale hydropower, including imports from Canada, as a clean energy resource.[41]

There are examples of Canadian hydropower supporting greater renewable energy development in the United States.[e] A 2013 Midcontinent ISO/Manitoba Hydro study explored the potential for Canadian hydropower to provide balancing for U.S. intermittent energy (primarily wind) and found that greater deployment supporting such an arrangement could provide economic and environmental benefits on both sides of the border, with annual modified production cost savings ranging from $228 million to $455 million for 2027, and annual load cost savings ranging from $183 million to $1,302 million for 2027.[42] Variations in planning and market design may require a different approach by region. In addition, lessons learned from examining the creation of economic and environmental benefits across international borders should be explored and disseminated when possible.

[d] According to the Energy Information Administration, natural gas prices for electric power fell from USD $9.26 per thousand cubic feet in 2008 to USD $3.37 per thousand cubic feet in 2015.

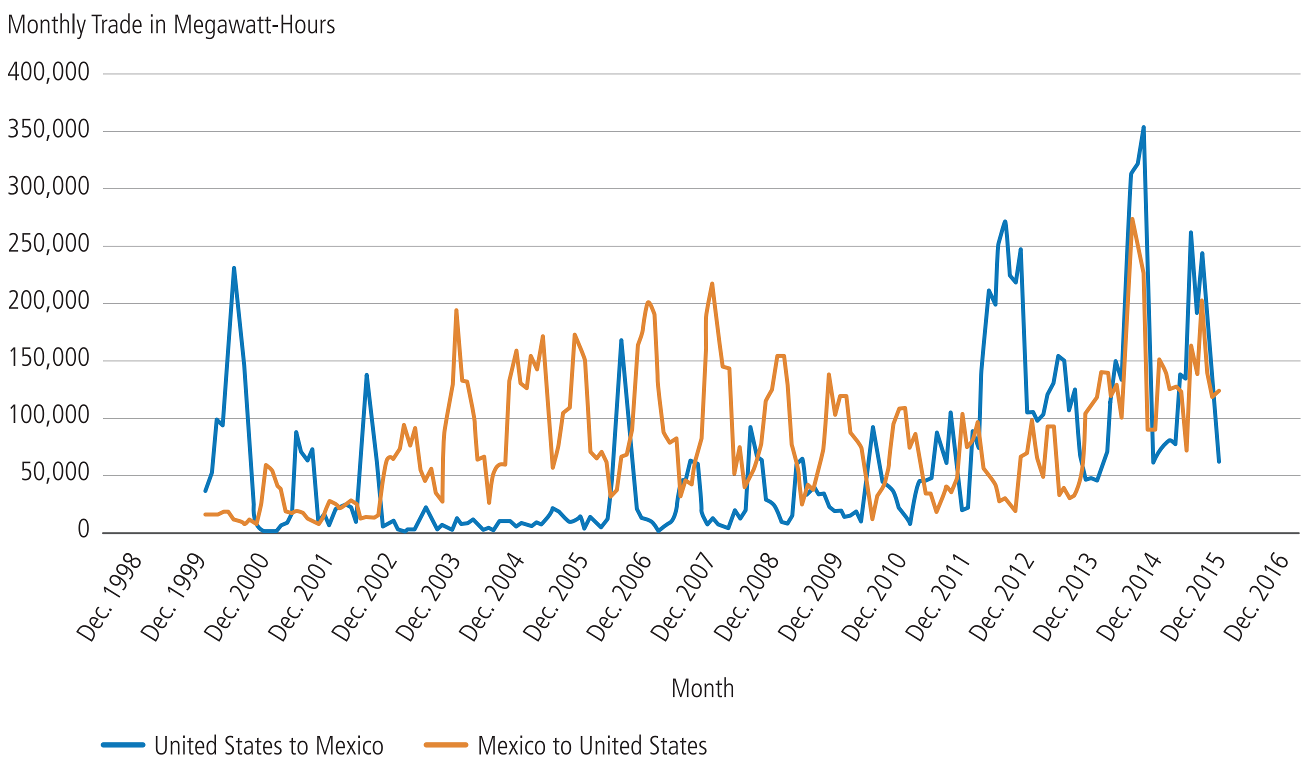
[e] This association is also suggested by the preliminary Regional Energy Deployment System projection shown for New York ISO in Figure 6-6.

U.S.-Mexico Integration

Due to a combination of historical, geographic, and resource factors, there is significantly less electricity integration between the United States and Mexico than between the United States and Canada. According to the Energy Information Administration (EIA), in 2015 the United States and Mexico traded approximately 7.69 million MWh total (compared to 77.2 million MWh traded between the United States and Canada), with the United States exporting 0.39 million MWh and importing 7.3 million MWh.[f]

A number of factors explain the differences: both Canada's and Mexico's border regions have experienced electricity shortages and lack reliable excess-generation resources[43] to export to the other; Mexico's states along the U.S. border have some of the lowest population densities in the country;[44, 45] and the border regions include areas with low (or insufficient) levels of existing transmission capacity. Two U.S. states—Texas and California—dominate the cross-border interactions with very different visions for integration. ERCOT shares the longest border with Mexico of any U.S. state, but all transmission connections between the Mexican grid and ERCOT are asynchronous, and trades are primarily for emergency backup, as illustrated in Figure 6-3. Because Baja California is not connected to the rest of the Mexican federal grid, robust California-Baja California cross-border integration may not lead to more integration opportunities in the absence of more domestic, long-distance transmission in Mexico.

Figure 6-3. Electricity Flows Between the United States and Mexico[46]



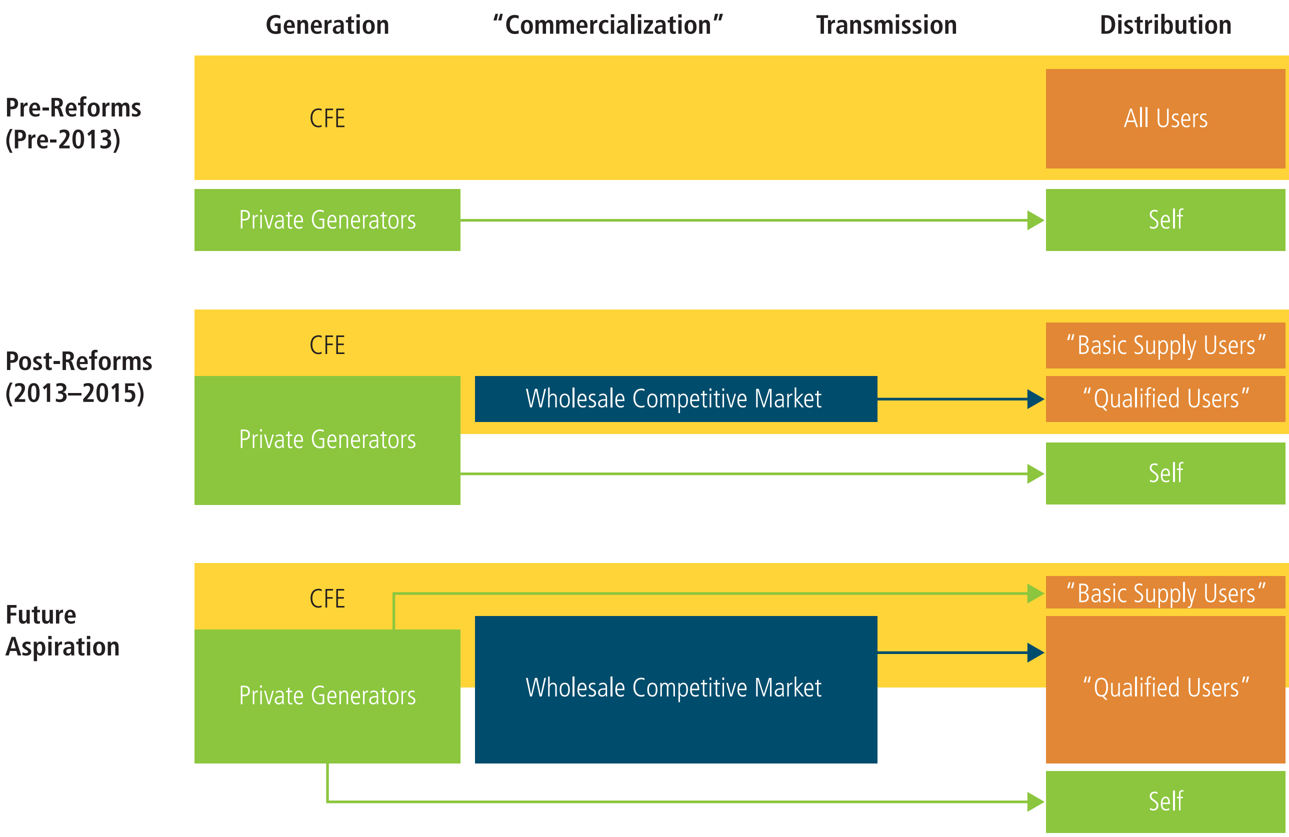
Monthly cross-border electricity trade between the United States and Mexico shows a number of differences with U.S.-Canada trade. For example, U.S.-Mexico trade occurs at lower volumes and is more sporadic and bidirectional. These are common features of trade flows that result when cross-border transmission is primarily used for emergency backup power. One important commonality, however, is that both U.S.-Mexican trade and U.S.-Canadian trade have been increasing since 2011.

[f] U.S. and Mexican estimates of U.S.-Mexico electricity trade vary significantly—a disparity that is being addressed by energy information institutions in both countries under the North American Energy Information Cooperation. Mexico's regulatory agency (Comisión Reguladora de Energía) and wholesale market operator (El Centro Nacional de Control de Energía) estimate total trade to be 4 million MWh in 2014, nearly double the EIA estimate.

Mexico's Energy Industry Reforms

Mexico's 2013 energy industry reforms, which included transformational structural reforms across the oil, gas, and power sectors, are highly relevant to cross-border electricity integration.[g] Until 2013, the Mexican Federal Electricity Commission (CFE)—the vertically integrated, state-owned utility—served as the sole producer, provider, and distributor of electricity in Mexico,[47] and private participation in the sector was reserved for the state except in limited situations (small power production, cogeneration, and independent power production). The existing framework, however, faced significant stress in the 1990s and early 2000s, caused by a mixture of external and structural factors, including high energy prices, low industrial competitiveness, government subsidization of electricity, lagging domestic fossil fuel production, and underinvestment in the power sector. Projected growth of power demand over the next decade led the government to pass extensive energy reforms in 2013, followed by a series of implementing laws that unbundled CFE and established a new wholesale electricity market to foster competition with private-sector participation (Figure 6-4).

Figure 6-4. Structural Changes Following Mexico's Energy Industry Reforms

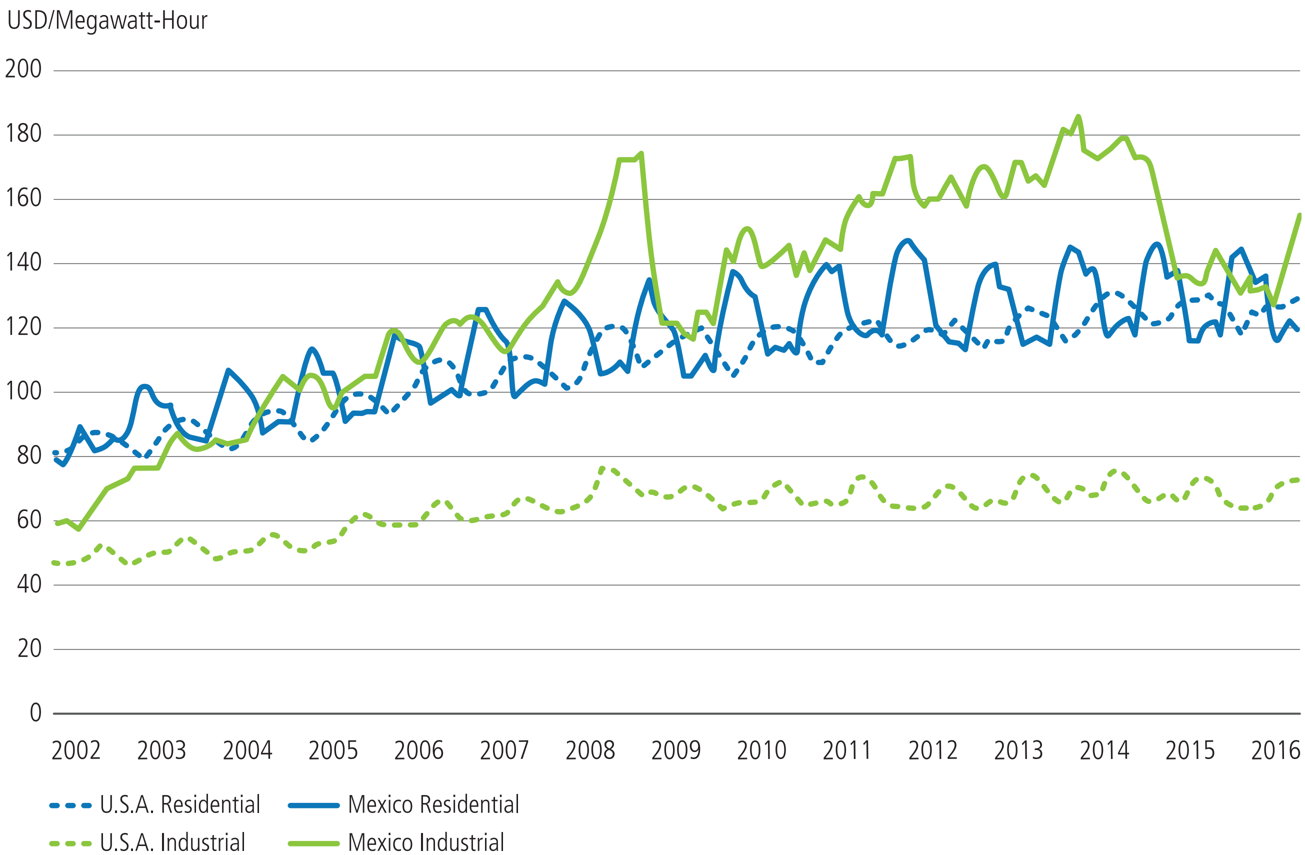


This figure is a simplified schematic, showing the adjustments in the Mexican power sector, pre-reforms, post-reforms, and future aspirations. Pre-reforms, CFE was vertically integrated and responsible for the generation, commercialization, transmission, and distribution of electricity to nearly all users, with exceptions for some forms of self-generation. The reforms created a wholesale competitive electricity market in which private generators can participate and divided users into "basic supply" users (those who consume under a given threshold and continue to receive direct service from CFE) and "qualified users" (those who consume over that threshold and are serviced by the wholesale competitive market). Over time, the wholesale market is intended to supply the majority of consumers. CFE continues to maintain control over transmission and distribution post-reforms.

[g] Unlike U.S. and Canadian power sector governance, which defers a number of authorities to state and provincial governments, Mexico's federal government is more centralized and also has near-complete authority in the power sector.

Under the new framework, the private sector is now free to participate in all aspects of the generation and sale of electricity, while CFE maintains physical control of transmission and distribution infrastructure and remains the sole provider to residential users with regulated tariffs, and the National Energy Control Center is now the ISO in charge of the operational control and administration of the new wholesale electricity market.[48] Many power sector stakeholders have called the reforms groundbreaking and admirable, including for reducing the strain of electricity consumption costs on industry in Mexico (Figure 6-5).[49]

Figure 6-5. Industrial and Residential Electricity Rates in the United States and Mexico, 1993–2013[50]



Different policies regarding industrial electricity and residential tariffs in the United States and Mexico, as well as different electricity generation sources (over the given period, Mexico used greater diesel/heavy fuel oil-fired generation, while the United States was more reliant on coal and natural gas) have led to a significant differential between U.S. and Mexican electricity rates. Of particular note, industrial rates in Mexico were slightly less than double U.S. rates in 2013, which impacts Mexican industrial competitiveness. Rates include government subsidies to Mexican residential consumers.

Reforms are focused on the overall goal of competitiveness, with twin objectives of helping consumers pay less for electricity and supporting cleaner electricity.[51] Currently, the industrial sector in Mexico faces costs per megawatt-hour of electricity that are almost double electricity costs in the United States, making production and goods more expensive for all of North America. In seeking lower energy prices for its consumers, Mexico is focusing on switching from fuel oil and diesel-fired generation in the power sector to natural gas (in part through greater imports from the United States[52]), reducing transmission and distribution losses (estimated at 16 percent of total generation in 2010), and increasing renewable energy deployment.[53] The impacts for Mexico's northern border region, specifically, could be significant as the region includes a number of industrial centers in Ciudad Juárez, Matamoros, Mexicali, Nogales, Nuevo Laredo, Reynosa, Tecate, and Tijuana.[54] One economic analysis estimates that transitioning from oil to natural gas for electricity production could have tremendous impacts on the manufacturing sector, where it could reduce electricity prices by 13 percent, boost manufacturing output by up to 3.9 percent, and increase overall gross domestic product by up to 0.6 percent.[55, 56]

Mexico is already seeing reductions in electricity prices; though the recent low oil and natural gas prices are likely a contributing factor, this trend is also likely to be stimulated by the reforms. From December 2014 to December 2015, electricity rates fell between 30 percent and 42 percent for industry. The wholesale electricity market also began to operate in January 2016, and renewable electricity generation capacity increased by 8.5 percent from 2013–2014 alone.[57] However, a differential in prices still exists: in the first 6 months of 2016, average wholesale prices in most locations of Mexico ranged from $48/MWh to $60/MWh,[58] while in Texas the ERCOT North 345-kilovolt peak wholesale prices over the same period were $22/MWh.[59]

Projected Actions and Potential Opportunities

Mexico's energy industry reforms may shift the cost-benefit analysis of enhanced integration in meaningful ways: these reforms were intended to increase generation in northern Mexico (including a number of industrial centers), stimulate private-sector investment in the power industry, lower energy costs, increase flows of natural gas from the United States, and increase renewable energy and energy efficiency deployment. All of these objectives could have implications for the attractiveness of increasing cross-border coordination and electricity trade.

According to analysis done by EIA, Mexico plans to build an additional 57 gigawatts of generation capacity from 2016 to 2030 and double natural gas imports from the United States from 2013 to 2018,[60] which will lead to a decline in electricity subsidies. The Program for Development of the National Electricity System, an annual report known by its Spanish acronym "PRODESEN," also demonstrates the intent to increase transmission capacity within Mexico, with some developments that could have impacts on cross-border trade, including connection of the Baja California Peninsula to the Mexican federal system by 2021 and construction of a new 150-megawatt asynchronous connection between Nogales, Sonora, and Arizona.[61, 62] The Mexican government is also studying the possibility of a larger east-west transmission line along the U.S. border, with the objective of enhancing transmission capacity in northern Mexico and facilitating cross-border trade.[63] Policy, regulatory, infrastructure, and economic changes in Mexico may lead to a number of other new opportunities.

The smart grid is a key area of focus; the PRODESEN report supports a smart grid program every 3 years to evaluate projects for the integration of new technologies into transmission, new wide-area monitoring systems, diagnostics and protections coordination using phasor measurements, and automation and modernization of substations. These investments will likely stimulate interest among U.S. generators to export electricity to Mexico, increase potential for flows from Mexico to the United States to supply U.S. demand for clean energy and essential reliability services, expand trade flows in both directions to enhance reliability, improve cooperation to stimulate clean energy development, and reduce GHG emissions. Mexico's increasing importation of U.S. natural gas has been and will remain an economic and environmental opportunity for both sides by offsetting expensive and high GHG-emitting diesel generation in Mexico and creating economic opportunities for U.S. exporters. The resulting reduction in electricity costs in Mexico could boost overall North American competitiveness and opportunities to integrate supply chains.[64]

Mexico has also established a program of clean energy certificates, which bears a resemblance to California's renewable energy credit system. Mexico's Transition Strategy has a significant focus on promoting clean technologies and fuels, with the goal of reaching 35 percent clean energy generation by 2024.[65] A variety of tools, such as the Clean Energy Zone Atlas, will help Mexico plan for the development of clean energy power plants and the expansion of the grid, similar to the Competitive Renewable Energy Zones in Texas. Two long-term clean energy auctions in 2016 produced record-low prices for energy, capacity, and clean energy certificates, and in the first auction, contracts were awarded with an average certificate price of USD $47.76; these projects will start operations in 2018. In the second auction, renewable projects—including solar, wind, geothermal, hydro, and combined-cycle natural gas (only for capacity)—produced three record-low prices for Latin America: a wind price of $32/MWh and a solar price of $27/MWh. These recent auction results indicate the opportunities in Mexico for renewable energy development. There are even instances where projects in Mexico qualify for California's RPS—the Energia Sierra Juarez project, a wind farm constructed miles from the California border, is one example of a Mexican project that has received certification to qualify. The Mexican government is fully committed to capitalizing on these opportunities, and its federal authority is sufficient to implement widespread changes.

There are several challenges raised by enhanced cross-border electricity integration with Mexico. Mexico's sector continues to experience high levels of technical and non-technical losses,[66] and it will need significant investments to improve system functionality to achieve greater efficiencies, especially in a scenario that includes significant increases in power trading with the United States' bulk power system. Mexico has different protections for open access to transmission from the United States and Canada. Though rules exist for access to government-owned transmission in Mexico, these are dissimilar to FERC Order Nos. 888 and 890.[67, 68] Additionally, both sides of the border have experienced power shortages in the past decade, suggesting that at this time neither border region has developed significant and reliable excess power to sell to the other on a firm basis.

The limitations of trade between Texas and the rest of the United States, vis-à-vis the Federal Power Act, do not apply to, and therefore are not a limitation on, ERCOT's electricity trade with Mexico. Though ERCOT has maintained a more isolated domestic trade strategy for electricity, the same Federal Power Act issues that drive these policies should not impact ERCOT-Mexico trade in electricity. The combination of challenges to trade, even though ERCOT shares the longest border with Mexico of any U.S. state, suggests that it will take a very compelling business case to enhance cross-border flows.

Emerging Integration Opportunities across North America

The extensive electricity integration that already exists between the United States and Canada, and the potential to increase existing integration between the United States and Mexico, suggest that North America has much to gain from collaborative planning, strategy, and cooperation in the power sector.

Carbon Trading and Pricing to Address Emissions in Mexico and Canada

In recent months, the federal governments of both Canada and Mexico have announced plans for new policies to address carbon dioxide emissions (Table 6-1). For several years, provinces and the private sector have pursued various forms of carbon accounting, charging, and trading. The electricity sector has and will play an important leading role in reducing economy-wide emissions of carbon dioxide. Given the highly integrated nature of the U.S.-Canada electricity system and the increasingly integrated state of the U.S.-Mexico electricity system, it will be important to explore the effects of implementing new federal carbon reduction policies across North America.

Subregional carbon markets are present all around the United States, including in states that border Mexico and Canada. The Regional Greenhouse Gas Initiative was the first mandatory carbon market in the United States, and it includes a cap-and-trade program for carbon dioxide emissions from power generators in the Northeast, Delaware, and Maryland (see Chapter III, *Building a Clean Electricity Future*, for additional detail). California and Quebec have had linked carbon markets since 2014, and Ontario will join those markets in 2018. Mexico and the province of Manitoba are also considering joining. As these arrangements evolve, the implications of these new markets for carbon trading should be examined further.

Table 6-1. New Carbon Trading and Pricing Policies in Canada and Mexico Are a First for North American Federal Governments

Canada	Mexico
	
Most of Canada's provinces have implemented initiatives to reduce carbon dioxide emissions from the power sector,[h] and 80 percent of Canadians live in a province where there is pollution pricing.[i] In September 2016, the federal government announced a "floor" carbon tax that will be introduced in 2018 at $10/ton of carbon. Under the federal program, the carbon price will rise $10/ton per year until 2022, when the price will freeze at $50/ton. Provinces have considerable implementation flexibility. The price can be in the form of a specific tax or levy, or as a cap-and-trade program, provided provinces set emissions caps that correspond to the expected reductions from the carbon price. The carbon tax will be revenue-neutral for the federal government, which will return funds to provinces from federally imposed carbon taxes. Any province can also levy the carbon tax and collect revenue itself, without involving the federal government, to meet the carbon pricing requirement.[j, k] A number of provinces, including British Columbia,[l] Alberta,[m] Ottawa, and Quebec,[n] are already in compliance with a carbon price for 2018, though the rising federal price of carbon will necessitate additional action from all provinces by 2022.	Mexico introduced a carbon tax on the use of fossil fuels in 2014. The initial price on carbon was set at U.S. dollars $3.5/ton of carbon.[o] In November 2016, Mexico launched its first federal initiative to deal with carbon, a pilot project with voluntary participation for study purposes of Mexico's new cap-and-trade program. The information will inform implementation of the 2018 launch of Mexico's new cap-and-trade program. The program is being guided by the Secretariat of Environment, the Mexican Stock Exchange, and the Mexican Carbon Platform, a private trading platform established in 2003. The platform involves voluntary participation of approximately 60 companies from various industries, including steel, cement, and chemicals, which combine to generate 70 million tons of carbon dioxide annually. Historically, the state of Baja California has been involved in California's carbon trading and clean energy policies for several years. To formally launch the cap-and-trade program in 2 years, Mexico will need to establish a cap on greenhouse gas emissions and create a program for monitoring and verification.[69, 70]

The electricity sector has and will continue to play an important leading role in reducing economy-wide emissions of carbon dioxide across North America. This table briefly describes recent announcements and actions by the federal governments of Canada and Mexico to address carbon dioxide emissions from the electricity system.

[h] Prince Edward Island has no current targets or initiatives in place; the territory of Nunavut is implementing climate adaptation strategies that do not address power generation. All other provinces and territories either have some form of emissions-reduction target and/or carbon pricing in place, including but not limited to mass-based targets, cap-and-trading, and RPS. Two territories, Northwest Territories and Yukon Territory, have voluntary energy efficiency targets in place for households and businesses that will reduce emissions from the power sector.

[i] "Government of Canada Announces Pan-Canadian Pricing on Carbon Pollution," Government of Canada, Ministry of Environment and Climate Change, October 3, 2016, http://news.gc.ca/web/article-en.do?nid=1132149.

[j] The Canadian Press, "5 things to know about Canada's carbon pricing plans," *Toronto Star*, October 3, 2016, https://www.thestar.com/news/canada/2016/10/03/5-things-to-know-about-canadas-carbon-pricing-plans.html.

[k] Bruce Campion-Smith, "Justin Trudeau's Liberals unveil plan to price carbon," *Toronto Star*, October 3, 2016, https://www.thestar.com/news/canada/2016/10/03/justin-trudeaus-liberals-unveil-plan-to-price-carbon.html.

[l] British Columbia currently has a carbon tax of $30/tonne.

[m] Alberta will levy a carbon tax on fuels at a rate of $20/tonne beginning in January 2017. One year later, the levy will increase to $30/tonne.

[n] Carbon was trading at $17 Canadian/tonne in May 2016 for the cap-and-trade market that includes Quebec and will include Ottawa (according to the International Carbon Action Partnership).

[o] Government of Mexico, Tax on Fossil Fuels, enacted in the Special Tax for Production and Services Law, Congress of Mexico, 2014.

Improving Grid Security and Reliability

Protecting the grid against vulnerabilities is a shared responsibility across North America. Most recently, the United States and Canada have agreed upon goals to (1) protect today's electricity grid and enhance preparedness, (2) manage contingencies and enhance response and recovery efforts, and (3) build a more secure and resilient future electric grid.[71] The joint U.S.-Canada Grid Security Strategy promotes improvements to information sharing, vulnerability assessment, emergency response and continuity, and management of new and evolving risks from grid technologies and design.[72]

The United States and Canada have developed respective national action plans to address and improve grid security. Going forward, there are key areas of mutual interest where joint cooperation can continue to grow between the United States and Canada. These include the Department of Energy (DOE) and Natural Resources Canada working in coordination with the Department of Homeland Security and Public Safety Canada to:

- Inform and support the private energy sector in response to a significant cyber incident
- Improve tools, frameworks, protocols, and methods for information sharing, risk assessment, and situational awareness
- Coordinate with existing table-top exercise formats
- Develop standardized curricula and training materials for utilities to educate their workforces on protection against threats, including cybersecurity.

Coordination of grid security efforts can lead to a more proactive approach to addressing emerging threats across North America. As Mexico's interconnections with the United States grow in number and capacity, it will be important for ongoing discussions of grid security goals and objectives to be informed by Mexico's experiences and perspective.

Mexico is working closely with NERC to achieve well-interconnected, secure, and stable electricity grids. Currently, an interministerial body (the Ministry of Energy, the System Operator, and the Regulatory Commission) has been set to produce a first version of Mexico's proposal of a memorandum of understanding with NERC. Along with this proposal, the group is working very closely with the staff of DOE, FERC, and the Western Electricity Coordinating Council to ensure consistency with other specific agreements.

As more interconnections are planned and built between the United States, Canada, and Mexico, the North America bulk power system must not only remain secure, but reliable as well. High-level cooperation between all three countries on energy issues should maintain a focus on the shared goal of a reliable electricity system for the continent. From coordination on high-level principles for reliability, to modeling and analysis to inform operations of the future bulk power system, cooperation across North America on reliability will complement efforts to improve security and ensure economic competitiveness.

Policy Options for North America

There are a variety of policy options that all three countries, and the United States individually, can take to support targeted action to enhance integration: (1) engagement—often high level and internationally through bilateral and trilateral dialogues and other cooperation mechanisms; (2) analysis—both cooperative and independent—carried out through working groups and projects; and (3) policy-level actions—primarily executed by domestic federal and state entities. Specific recommendations are described more thoroughly in Chapter VII (*A 21st-Century Electricity System: Conclusions and Recommendations*).

Additionally, while many detailed electricity sector modeling tools exist for the United States (and in some cases, the United States and Canada), modeling tools capable of analyzing the economic, environmental, social, or reliability impacts of electricity integration throughout North America are relatively coarse. Improved models would lead to more informative and useful results to enable better stakeholder decisions.

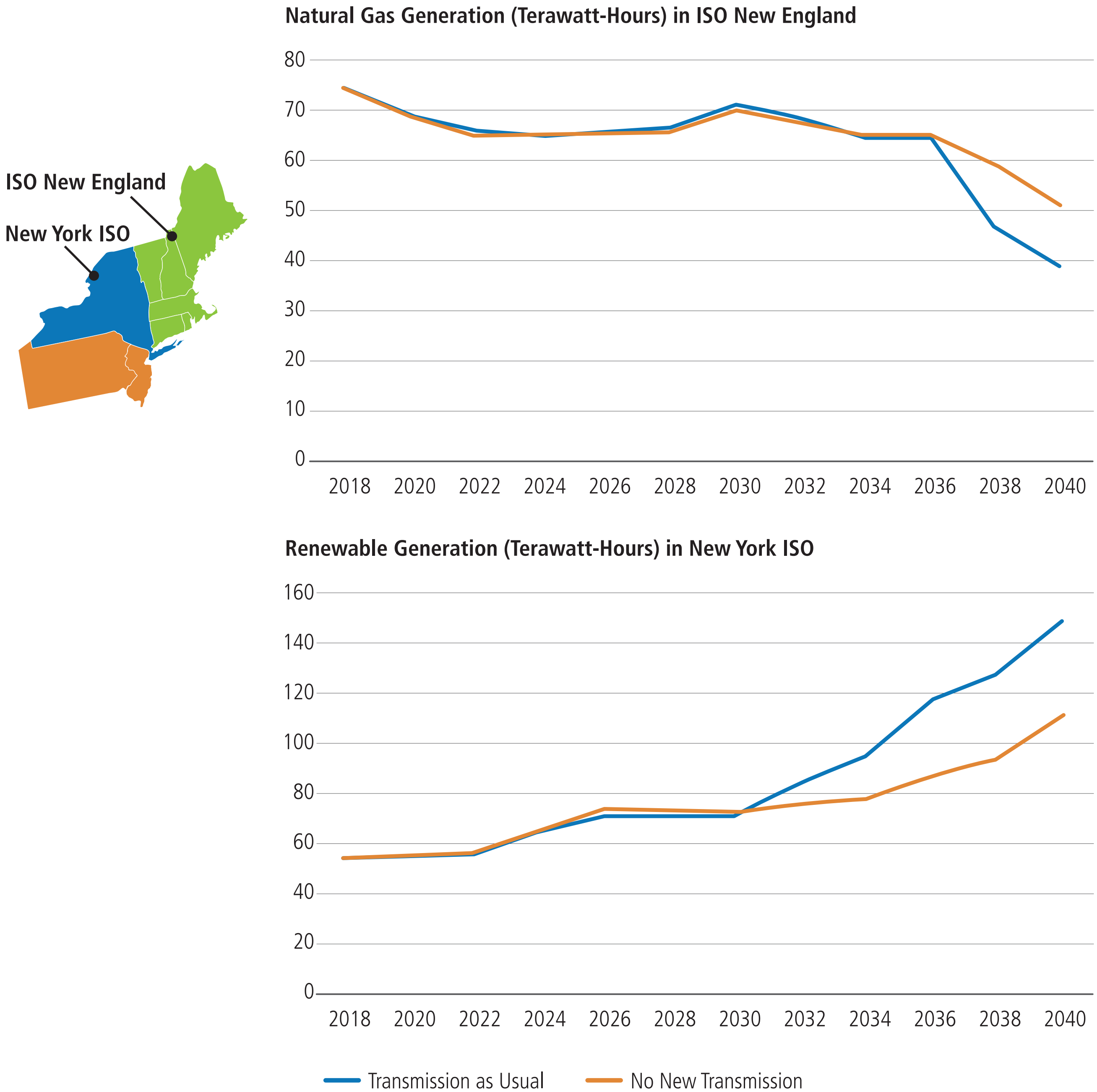
Analysis of Cross-Border Electricity Policy

While there is a diversity of power sector modeling tools to analyze U.S. grid or market operations at varying levels of detail and accuracy, such tools do not yet exist at a robust level for the combined power system of Canada, Mexico, and the United States, limiting the ability of modeling to estimate costs and benefits of increasing cross-border trade.[73] One exception is the Regional Energy Deployment System (ReEDS), which does represent both the United States' and Canada's power systems.[74] Sample, preliminary analysis from this model is highlighted in Figure 6-6. DOE's Office of Energy Efficiency and Renewable Energy is working with the National Renewable Energy Laboratory to expand this model to Mexico in cooperation with the Mexican Secretariat of Energy and the Mexican National Energy Control Center. Final results will be used to understand the implications of a variety of U.S.-Mexican energy scenarios, inform decision making about renewable energy integration and cross-border energy markets, and establish the analytical framework for long-term strategic thinking about a shared North American energy future.

DOE, Natural Resources Canada, and Mexico's Secretariat for Energy are also supporting a 3-year effort through the North American Renewable Integration Study (NARIS) to share data and enable modeling and analysis of coordinated planning and operations across North America under high-market-penetration renewable energy scenarios. The ReEDS United States, Canada, and Mexico models will be used to inform the NARIS study scenarios. The NARIS study will be completed in 2018.

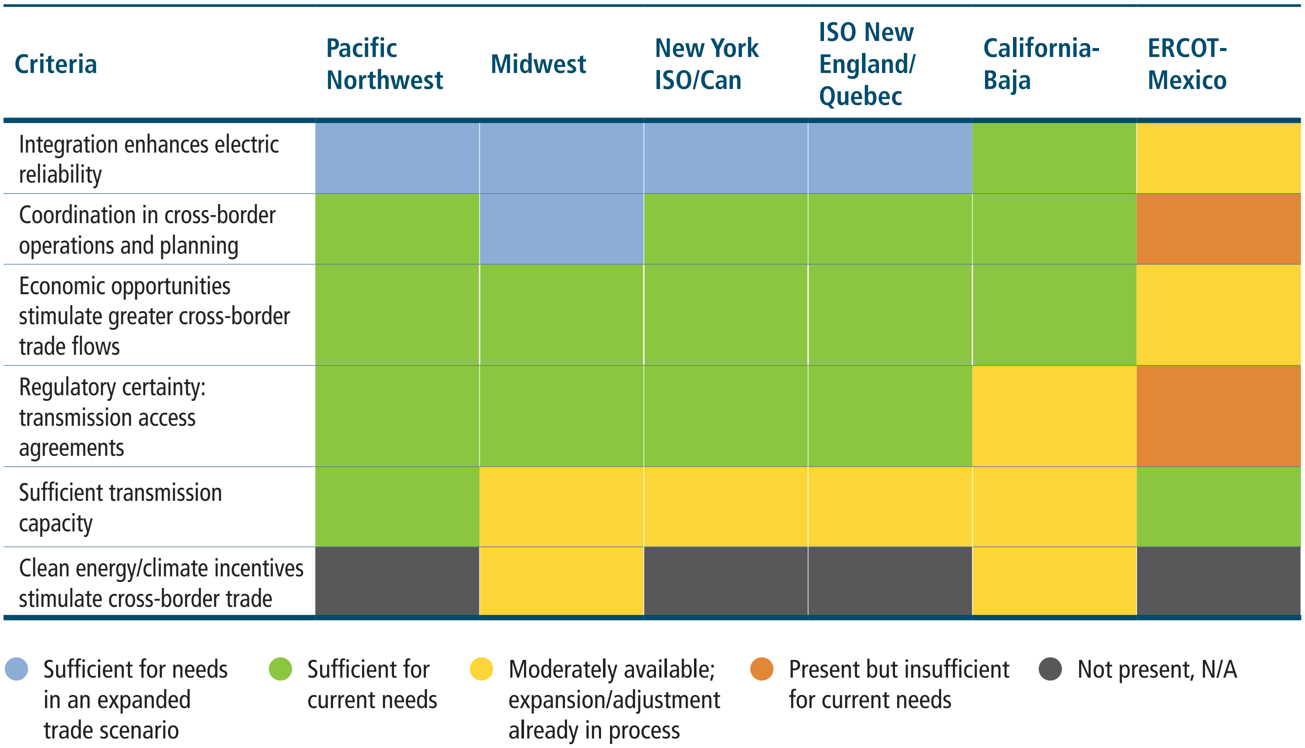
Though not scenario-based, complementary qualitative analyses (Table 6-2) can allow policymakers to understand the current status of integration and the relevance of specific factors to impact cross-border trade opportunities.

Figure 6-6. Possible Long-Term Impacts of Cross-Border Transmission on Regional Generation Mix in the United States, 2018–2040



Under a low-carbon future scenario, results from ReEDS show that transmission with Canada becomes increasingly important for sustaining emissions reductions and has a significant impact on the generation mix in border regions. In ISO New England, greater cross-border transmission capacity reduces domestic natural gas generation. In New York ISO, additional transmission capacity with Canada is associated with an increase in domestic renewable generation.

Table 6-2. Analysis of Variables That Have Led to Current Levels of Cross-Border Trade in Cross-Border Trade Relationships



The analysis, done by DOE's Office of Energy Policy and Systems Analysis, demonstrates the variables that have contributed to differences in the level of cross-border integration observed in each cross-border interaction, with robust cross-border integration between the United States and Canadian counterparts, and less developed integration between the United States and Mexico. Cross-border ties with Arizona and New Mexico were not included due to their small capacity.

Table 6-2 assesses the degree to which cross-border electricity trade in each region has met the criteria that must be present in order to increase international trade in electricity. Cross-border trade in electricity must provide for customer demand across the border, enhance reliability, provide sufficient transmission capacity, coordinate cross-border operations and planning, and provide regulatory certainty. Additionally, incentives for clean energy can also influence cross-border trade and have been included in this table. Looking at the assessment, it is clear that some key factors required for enhanced integration are still emerging on the U.S.-Mexico border, while supporting factors for cross-border trade in regions shared by the United States and Canada are already in place. This table points also to areas for further work and cooperation among regional stakeholders and governments, including for transmission capacity development.

The extraordinary complexity of the North America bulk power system means that policymakers and other stakeholders will require robust and extensive analysis to understand the implications of any specific action. Three main elements comprise what is necessary for analysis:

- Access to consistent energy information and data from all three countries (including information regarding generation, transmission, and distribution functions and expansion plans, electricity flows, and pricing).
- Access to information on existing policy, regulatory, and operational features of the power system at the national, state/provincial, ISO, and local levels.
- Rigorous power sector modeling capabilities that can provide estimates of economic, environmental, social, and operational benefits and costs at varying levels of detail.

Descriptions of analyses that will enhance North American electricity integration can be found in Chapter VII (*A 21st-Century Electricity System: Conclusions and Recommendations*).

Electricity Engagement between Canada, Mexico, and the United States

Engagement between Canada, Mexico, and the United States will serve to align national objectives. For example, trilateral and bilateral dialogues or mechanisms for cooperation, including the North American Leaders' Summit, North America Energy Ministers' Meetings, and the Working Group on Climate Change and Energy; trilateral and bilateral memoranda of understanding; the U.S.-Canada Regulatory Cooperation Council; and bilateral dialogues with Canada (U.S.-Canada Clean Energy Dialogue, U.S.-Canada Energy Consultative Mechanism) and Mexico (U.S.-Mexico High Level Economic Dialogue, U.S.-Mexico Task Force on Clean Energy and Climate Policy, U.S.-Mexico Bilateral Framework on Clean Energy and Climate Change) provide a comprehensive set of diplomatic and working group opportunities for leaders to provide a high-level commitment to action, establish national priorities, establish working groups and task forces to explore specific topics in greater detail, and coordinate developments internationally. Additionally, meetings of leaders at which commitments are made, including the recent goal of 50 percent clean power generation by 2025 for North America, can provide an important forum for engagement. All of these efforts can help to align development and technical assistance efforts, expand networks beyond governments to include key stakeholders from the private sector and other relevant power sector institutions or multilateral development institutions, and stimulate new interest in analysis of other policy options.

Descriptions of recommended engagements to enhance North American electricity integration can be found in Chapter VII (*A 21st-Century Electricity System: Conclusions and Recommendations*).

Specific Policy-Level Actions

Finally, at the most granular level, specific policies can be implemented, strengthened, or adjusted to support enhanced integration. These policy actions range from domestic financial incentives that affect cross-border trade (e.g., tax policy, export tariffs, and clean energy incentives) to regulatory frameworks that could be improved to ensure more coordinated yet robust functioning of existing governance (e.g., permitting processes).

Descriptions of policy actions that will enhance North American electricity integration can be found in Chapter VII (*A 21st-Century Electricity System: Conclusions and Recommendations*).

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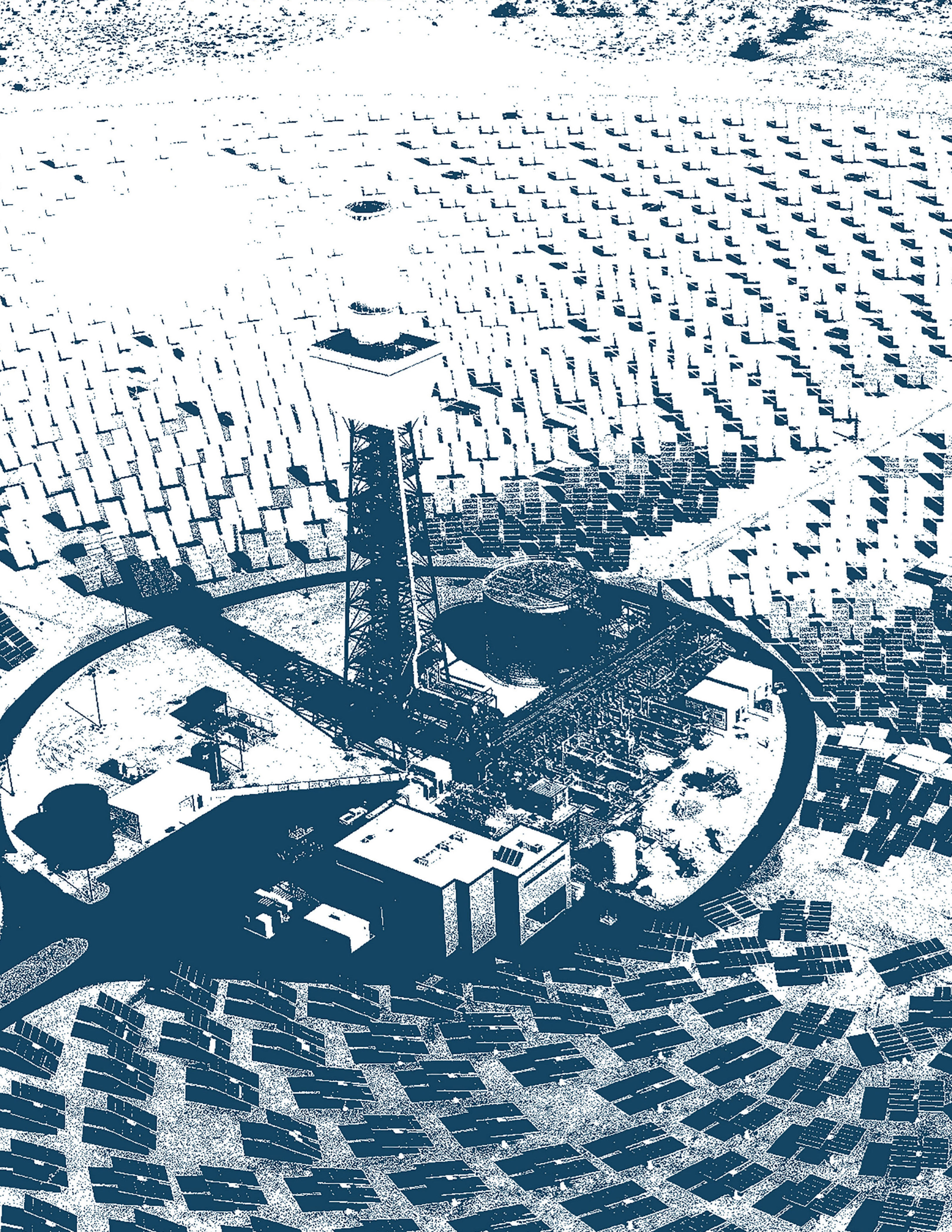


Chapter VII

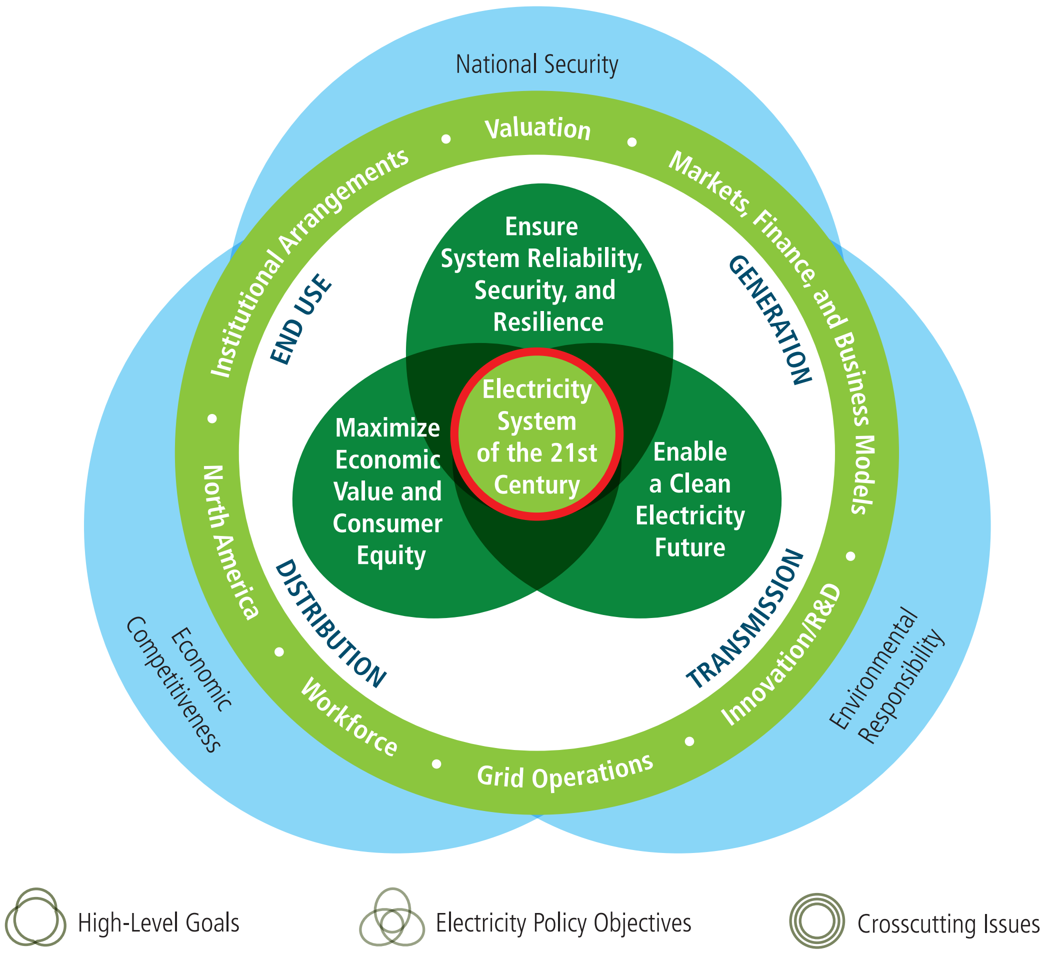
A 21ST-CENTURY ELECTRICITY SYSTEM: CONCLUSIONS AND RECOMMENDATIONS

This chapter highlights many recommendations that will enable the necessary modernization and transformation of the 21st-century electricity system. The 76 recommendations build on the analysis and findings in earlier chapters of this second installment of the Quadrennial Energy Review (QER 1.2). Many of the recommendations will provide the incremental building blocks for longer-term, planned changes and activities, undertaken in conjunction with state and local governments, policymakers, industry, and other stakeholders. The policy, research, and investment choices made today will establish critical pathways for decades.

Key National Security and Reliability Priorities for a 21st-Century Electricity Sector

The electricity sector is a complex system of overlapping interests, investments, and impacts that affect industry, businesses, consumers, and communities served by electricity providers. Accordingly, migration from the present state to a desired outcome for the 21st-century electricity sector (Figure 7-1) requires recognition of critical crosscutting factors that should be addressed as superordinate to the perspectives discussed in preceding chapters. These high-level, crosscutting issues and recommendations address national security, reliability, jurisdictional adjustments, technology investments, streamlined regulatory processes, better gathering and use of data and analysis, and realistic assistance solutions to enable key elements of a 21st-century electricity system.

Figure 7-1. Goals, Objectives, and Organization of QER 1.2



The central finding in the second installment of the Quadrennial Energy Review (QER 1.2) is as follows: "**As a critical and essential national asset, it is a strategic imperative to protect and enhance the value of the electricity system through modernization and transformation**."

The Electricity System as a National Security Concern

A set of actions and recommendations in QER 1.2 address the fundamental role of the Federal Government: promoting national security and ensuring the national defense. To this end, it is worth restating a key conclusion from Chapter I (*Transforming the Nation's Electricity System: The Second Installment of the Quadrennial Energy Review*) to illustrate the essential and growing role electricity now plays in this fundamental function of the Federal Government. The conclusion of a 2015 report from the Center for Naval Analyses notes,

> "Assuring that we have reliable, accessible, sustainable, and affordable electric power is a national security imperative. Our increased reliance on electric power in every sector of our lives, including communications, commerce, transportation, health and emergency services, in addition to homeland and national defense, means that large-scale disruptions of electrical power will have immediate costs to our economy and can place our security at risk. Whether it is the ability of first responders to answer the call to emergencies here in the United States, or the readiness and capability of our military service members to operate effectively in the U.S. or deployed in theater, these missions are directly linked to assured domestic electric power."[1]

The analysis in QER 1.2 reaches a similar conclusion: the reliability of the electric system underpins virtually every sector of the modern U.S. economy—from food production to banking to health care. Electricity is at the center of key infrastructure systems that support these activities—transportation, oil and gas production, water, finance, and information and communications technology. Electricity-dependent critical infrastructures represent the core underlying lifeline framework that supports the American economy and society.

The range of goods and services that involve grid communications and two-way electricity flows, including the Internet of Things (IoT), represents significant value creation and greatly supports and enhances our economy and global competitiveness. At the same time, these goods and services place new demands on the electric grid for high levels of reliability, smarter components, visibility, analytics, and system-wide planning. These features and services also introduce new vulnerabilities to our electricity system (e.g., accelerated time scales sufficient to require significant automation and cybersecurity) that rise to the level of national security concerns.

These vulnerabilities are underscored by the October 21, 2016, hacking incident of simple home devices. Figure 7-2 shows the location of key data centers that support the Internet (discussed in detail in Chapter I, *Transforming the Nation's Electricity System: The Second Installment of the Quadrennial Energy Review*), as well as the global impacts of this event. In this incident, the "Mirai" botnet used internet-connected devices, including baby monitors, to create the largest denial-of-service attack in history. The impact of this event was amplified by the U.S. Domain Name System company (called Dyn), infecting 100,000 IoT devices deployed throughout the world (Figure 7-3).[2] The IoT devices in foreign countries worked together to attack a U.S. company. This attack underscores the national security and economic vulnerabilities associated with interconnectedness and the growing proliferation of unhardened consumer devices on the distribution network that have the potential to infect bulk power systems.

Figure 7-2. Primary Data Centers for Major Service Providers[3]

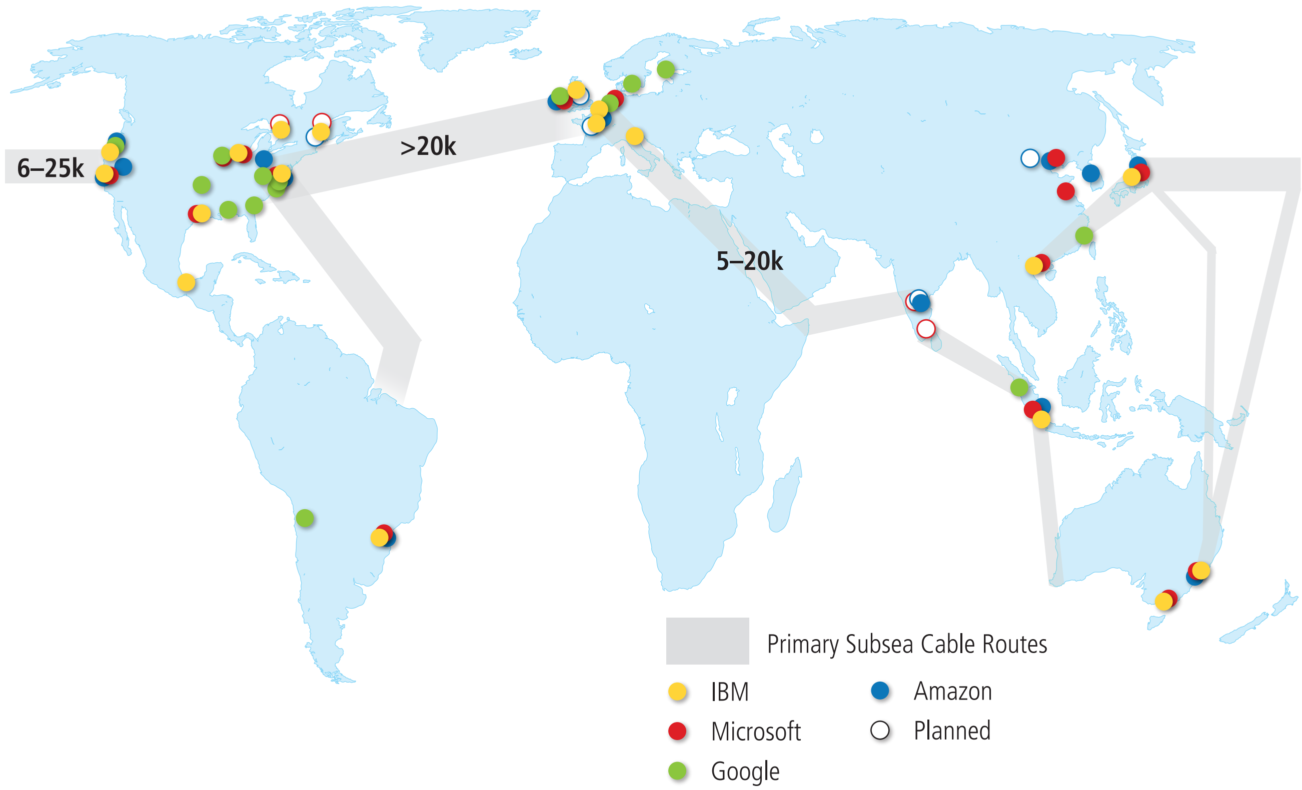
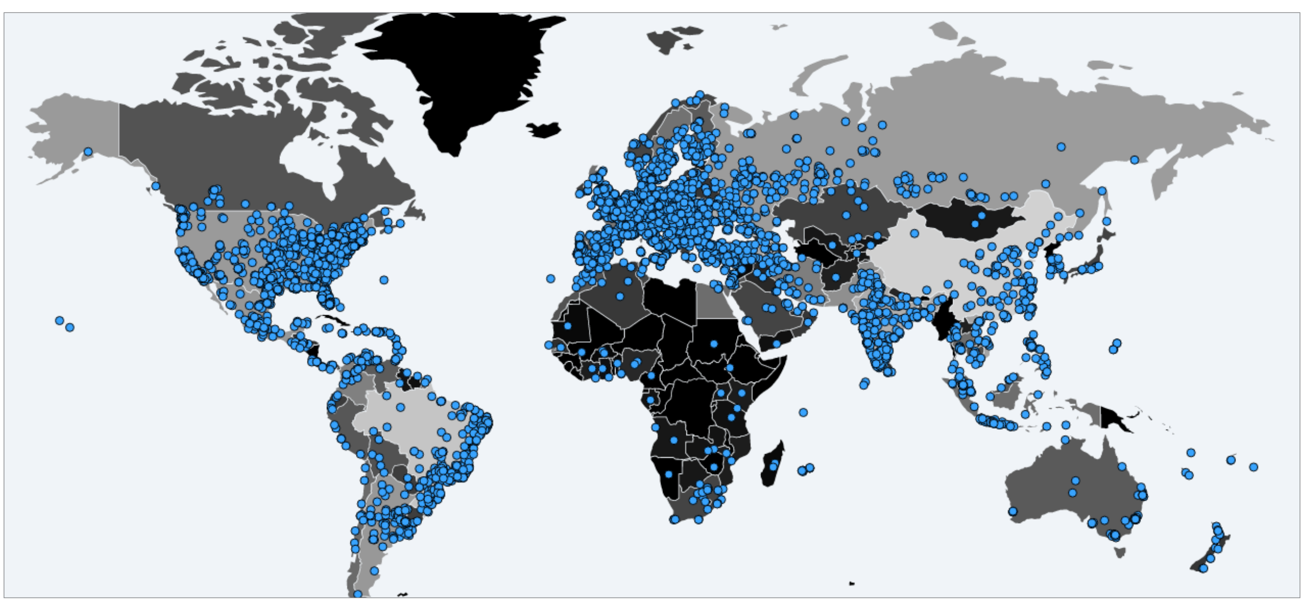


Figure 7-3. The Global Reach of the October 21, 2016, Hack[4]



The global internet is supported by a worldwide network of subsea cables and large-scale data centers operated by firms such as Amazon, Google, IBM, and Microsoft (Figure 7-2) This global reach and interconnectedness, however, also introduces vulnerabilities for U.S. assets and systems that can be affected by connected devices worldwide, as was seen in the October 21, 2016, "Mirai" botnet attack (Figure 7-3, with blue depicting the global impacts of the attack). The global exposure of the "internet of things" merits deliberate risk-management activities as the electric power sector becomes increasingly interconnected with global communications networks.

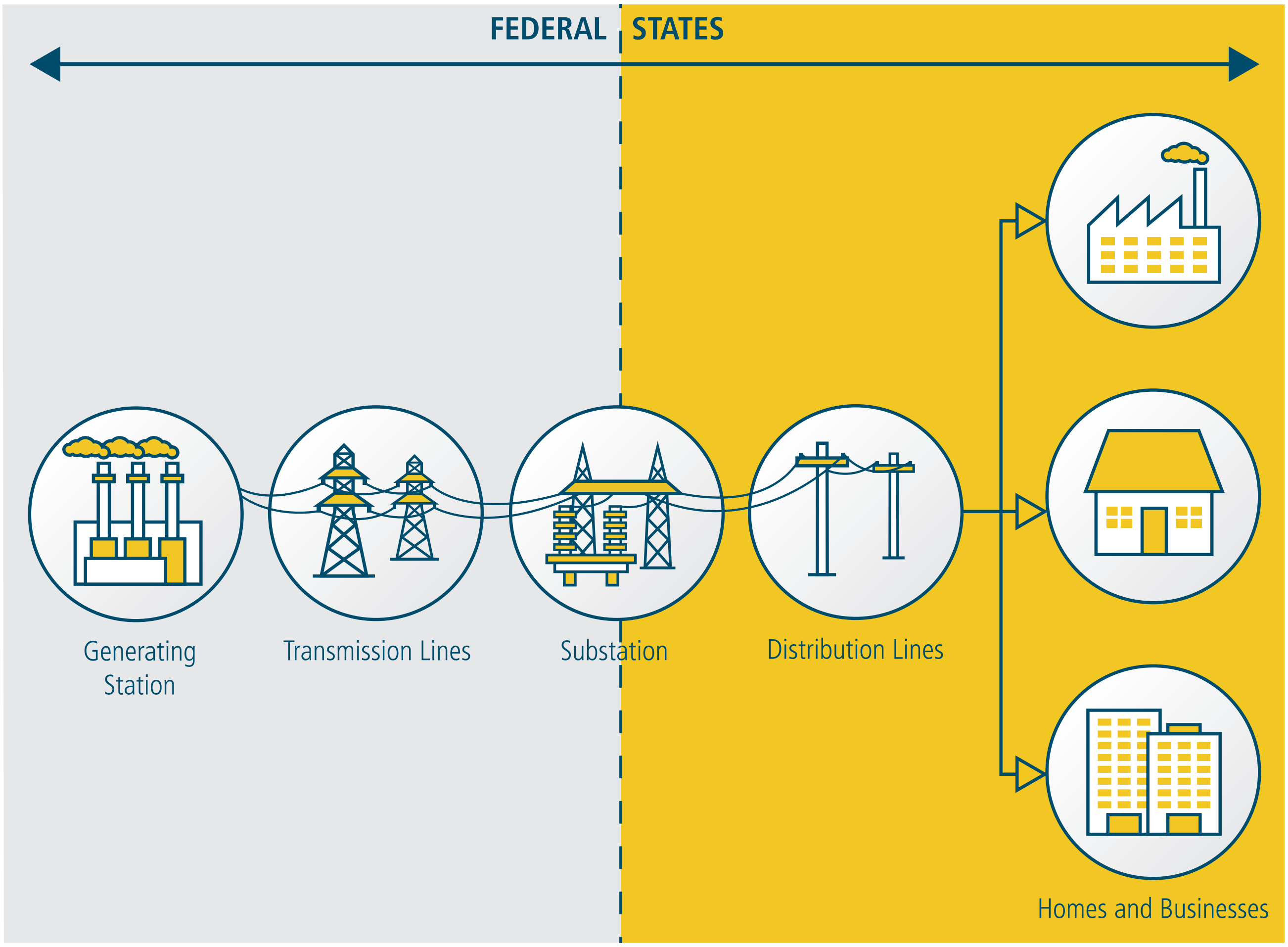
As noted in Chapter I (*Transforming the Nation's Electricity System: The Second Installment of the Quadrennial Energy Review*) and worth repeating here, Congress has recognized the national security implications of the electricity system in the Fixing America's Surface Transportation Act (FAST Act), passed in December 2015. To place the recommendations in QER 1.2 in context, it is important to repeat key language in the Act. The FAST Act gives the Secretary of Energy new emergency authorities for "critical electric infrastructure," where, upon a directive from the President, the Secretary may "with or without notice, hearing or report, issue such orders for emergency measures as are necessary…to protect or restore the reliability of critical electric infrastructure or of defense critical infrastructure during an emergency." These authorities apply to

> "the occurrence or *imminent danger of* [italics added]…electronic communication or an electromagnetic pulse, or a geomagnetic storm event that could disrupt the operation of those electronic devices or communications networks, including hardware, software, and data, that are essential to the reliability of critical electric infrastructure or of defense crucial electric infrastructure…the disruption of the operation of such devices or networks, with significant adverse effects on the reliability of critical electric infrastructure or of defense critical electric infrastructure…a direct physical attack on critical electric infrastructure or on defense critical infrastructure; and significant adverse effects on the reliability of critical electric infrastructure or of defense critical electric infrastructure as a result of such physical attack."[5]

Four essential observations should be made about these provisions. First, there are, in effect, anticipatory authorities in the law, described in the FAST Act as events that present "imminent danger." Second, the provisions of the law are tied to the *reliability* of critical electric infrastructure, directly linking reliability to security. Third, the increasing reliance of the electricity system on natural gas—it is now the number one primary fuel source for power generation for the first time—makes security information about related gas infrastructures a critical component for decision making under the FAST Act. Finally, cyber threats do not respect jurisdictional boundaries.

Figure 7-4 clearly illustrates the interconnectedness of the electricity system; the national security responsibilities included in the FAST Act must be addressed without regard to jurisdictional boundaries.

Figure 7-4. Current Jurisdictional Boundaries and the Security of the Electricity System[6]



The U.S. electricity sector regulatory authorities are generally split between the Federal Government for generation and transmission assets and states for distribution networks. The 2015 FAST Act specifies Federal authorities to address critical electric infrastructure emergencies.

In addition, the interconnectedness of our modern grid was underscored by the Supreme Court's decision on Federal Energy Regulatory Commission (FERC) Order No. 745. While the Court's majority opinion on Order No. 745 acknowledged that FERC, in this order, only addressed wholesale markets, it also noted,

> "It is a fact of economic life that the wholesale and retail markets in electricity, as in every other known product, are not hermetically sealed from each other…To the contrary, transactions that occur on the wholesale market have natural consequences at the retail level. And so too, of necessity, will FERC's regulation of those wholesale matters…When FERC regulates what takes place on the wholesale market, as part of carrying out its charge to improve how that market runs, then no matter the effect on retail rates, [the Federal Power Act] imposes no bar."[7]

Recent FERC actions are designed to address and clarify key security issues, as well as issues raised by two-way flows and a modern electricity system. FERC has issued an order pursuant to the FAST Act to control the availability of sensitive critical energy infrastructure information on "production, generation, transmission and distribution of energy," noting that a single critical energy infrastructure information process is "…the most efficient way to fulfill the statutory mandate of the FAST Act and to avoid any confusion that could result from different processes for different types of critical infrastructure information."[8] FERC has also taken steps to enable the aggregation of storage, including at customer facilities, examining the need to develop participation models consisting of market rules.[9]

Integrated Planning Needed to Address National Security Imperatives of the Electricity System

National security investments, regardless of scale, are costs that should be born, in part, by the Federal Government acting on behalf of all Americans. Sorting out how costs should be allocated will be a critical success factor in achieving and sustaining a secure grid throughout this century. New authorities must come with appropriate budgets for Federal responsibilities, and costs to be carried by ratepayers must be made explicit as well. Managing investment requirements while keeping affordability in mind must be a key concern of the Federal Government. While most analysts do not think that these costs will cause rate shocks, having mechanisms for clearly articulating the associated Federal and ratepayer costs will be important for security and public acceptance.

QER 1.2 discusses the limits of existing reliability and resilience planning methodologies and processes in Chapter IV (*Ensuring Electricity System Reliability, Security, and Resilience*). There are many planning methods currently used by utilities, ranging from integrated resource planning to more-focused procurement planning. Despite the breadth and depth of current and emerging planning methods, there are gaps in standards, operational definitions, and geographic scope. There are also several levels of planning as well, such as state-level regulatory planning; state energy office planning; independent system operator/regional transmission organization regional planning; North American Electric Reliability Corporation (NERC) regional planning; and FERC planning requirements, which affect all entities regulated by FERC. Still, when aligned with a map of the Nation, there are no adopted common demarcations that enable consistent and seamless planning related to grid security that can serve the need for a national security overlay.

Key Crosscutting Recommendations to Support the Security and Reliability of the Electricity System

Protect the Electricity System as a National Security Asset

The Federal Power Act provides a statutory foundation for an electricity reliability organization to develop reliability standards for the bulk power system. Pursuant to this authority, FERC has certified NERC as the Electric Reliability Organization. Under this arrangement, NERC and FERC have put into place a comprehensive set of binding reliability standards for the bulk power system over the past decade, including standards on cybersecurity and physical security. However, the Federal oversight authority is limited: FERC can approve or reject NERC-proposed reliability standards, but it cannot author or modify reliability standards.

The nature of a national security threat, however, as articulated in the FAST Act, stands in stark contrast to other major reliability events that have caused regional blackouts and reliability failures in the past. In the current environment, the U.S. grid faces imminent danger from cyber attacks, absent a discrete set of actions and clear authorities to inform both responses and threats. Widespread disruption of electric service because of a transmission failure initiated by a cyber attack at various points of entry could undermine U.S. lifeline networks, critical defense infrastructure, and much of the economy; it could also endanger the health and safety of millions of citizens. Also, natural gas plays an increasingly important role as fuel for the Nation's electricity system; a gas pipeline outage or malfunction due to a cyber attack could affect not only pipeline and related infrastructures, but also the reliability of the Nation's electricity system.

1. **Amend Federal Power Act authorities to reflect the national security importance of the Nation's electric grid.** Grid security is a national security concern—the clear and exclusive purview of the Federal Government. The Federal Power Act, as amended by the FAST Act, should be further amended by Congress to clarify and affirm the Department of Energy's (DOE's) authority to develop preparation and response capabilities. These capabilities will ensure that DOE is able to issue a grid-security emergency order to protect critical electric infrastructure from cyber attacks, physical incidents, electromagnetic pulses (EMPs), or geomagnetic storms. In this regard, Federal authorities should include the ability to address two-way flows that create vulnerabilities across the entire system. DOE should be supported in its development of exercises and its facilitation of the penetration testing necessary to fulfill FAST Act emergency authorities. In the area of cybersecurity, Congress should provide FERC with authority to modify NERC-proposed reliability standards—or to promulgate new standards directly—if it finds that expeditious action is needed to protect national security in the face of fast-developing new threats to the grid. This narrow expansion of FERC's authority would complement DOE's national security authorities related to grid-security emergencies affecting critical electric infrastructure and defense-critical electricity infrastructure. This approach would maintain the productive NERC-FERC structure for developing and enforcing reliability standards, but it would also ensure that the Federal Government could act directly, if necessary, to address national security issues.

2. **Collect information on security events to inform the President about emergency actions, as well as imminent dangers.** DOE should collect targeted data on critical cyber, physical, EMP, and geomagnetic disturbance events and threats to the electric grid to inform decision making in the event of an emergency or to inform the anticipatory authorities in the FAST Act. DOE should concurrently develop appropriate criteria, processes, and definitions for collecting these targeted data using a dedicated information-protection program to safeguard utility data consistent with FERC rules. Reporting will be done on a confidential basis. Updating will be required to address evolving threats. DOE will coordinate the development of analytical data-surveillance and data-protection tools with the National Labs, states, universities, industry, Federal agencies, and other organizations as appropriate.

3. **Adopt integrated electricity security planning and standards.** FERC should, by rule, adopt standards requiring integrated electricity security planning on a regional basis to the extent consistent with its statutory authority. Such requirements would enhance DOE's effectiveness in carrying out its responsibilities and authorities to address national security imperatives and new vulnerabilities created by (1) two-way flows of information and electricity and (2) the transactive role of customers and key suppliers (such as those providing stored fuel for strategic generators). Important national security considerations warrant careful consideration of how generation, transmission, distribution, and end-user assets are protected from cybersecurity risks. Vulnerabilities of distribution and behind-the-meter assets, which may provide an increasing number of potential entry points for access to utility control systems, are threats that can adversely affect the operation of the transmission system; for these vulnerabilities, a careful review of protections is required. To adequately address and support the security requirements of the FAST Act and DOE's implementation of the FAST Act, this review should be performed on an integrated basis, rather than separating the review into the bulk power system and other assets.

   To ensure that there are no unnecessary vulnerabilities associated with state-to-state or utility-to-utility variations in protections, integrated electricity security planning should be undertaken to cover the entire United States, including Alaska, Hawaii, and U.S. territories. FERC should consider having existing regional organizations undertake such planning, as it deems appropriate. FERC should evaluate whether the costs of implementing security measures identified in the integrated electricity security plan are appropriate for regional cost allocation, where such measures are found to enhance the security of the regional transmission electric system.

To the extent necessary, appropriate statutes should be amended to clearly authorize FERC to adopt such integrated electricity security planning requirements. However, FERC should immediately begin to advance this initiative to the maximum extent possible under its current authority by initiating a dialogue, including discussions with DOE and state authorities, and driving consensus on Integrated Electricity Security Plans.

4. **Assess natural gas/electricity system infrastructure interdependencies for cybersecurity protections.** DOE, pursuant to FAST Act authorities and in coordination with FERC, should assess current cybersecurity protections for U.S. natural gas pipelines and associated infrastructure to determine whether additional or mandatory measures are needed to protect the electricity system. If the assessment concludes that additional cybersecurity protections—including mandatory cybersecurity protocols—for natural gas pipelines and associated infrastructure are necessary to protect the electricity system, such measures and protocols should be developed and implemented. This work should build on existing assessments, including those underway at the Transportation Security Administration.

Increase Financing Options for Grid Modernization

Estimates of total investment requirements necessary for grid modernization range from a low of about $350 billion to a high of about $500 billion.[10, 11] Grid modernization is the platform for the 21st-century electricity system, bringing significant value associated with lower electricity bills due to fuel and efficiency savings, more electricity choices, and fewer and shorter outages. The Federal Government currently plays a role in providing tax incentives for the deployment of clean energy technologies (discussed further in Chapter III, *Building a Clean Electricity Future*), as well as Federal credit assistance to facilitate early deployment of innovative technologies.

5. **Expand DOE's loan guarantee program and make it more flexible to assist in the initial deployment of innovative grid technologies and systems.** The design of the current DOE loan guarantee program is focused primarily on financing the deployment of innovative generation technologies. Most DOE loan guarantee recipients, for example, are structured as special project entities that can raise equity outside of regulated business structures and can provide credit security in the form of power purchase agreements. This financing model is not amenable to grid-modernization financing by regulated entities, especially in cases of some technological uncertainty associated with initial commercial deployments. In addition, there will be an ongoing need for innovation in grid technologies beyond the likely availability of current DOE loan guarantee authority. Also, the limitations of the loan program restrict the program to a very small and ever-changing portion of new transmission capacity; more projects and innovation are necessary to transform the grid.

   Modifications to the current DOE Title XVII loan guarantee program are needed to (1) reduce restrictions on numbers/types of projects and time frames (e.g., in order to adequately address innovative transmission capacity needs), and (2) provide clear statutory authority for lending to other public or public/private entities that support transmission and other grid-modernization projects (e.g., state agencies, regional power pools) through on-lending or equity investing. By their nature, transmission projects, especially big projects, involve many entities and jurisdictions. Statutory clarification is needed on indirect lending authorities to such entities for multi-jurisdictional projects.

   Some of the benefits of grid modernization are realized over time, as the electricity system itself is changed by technology and market innovations. Additional funding resources would bridge the gap between investment costs and realization of benefits, and they would enable utilities to invest in grid modernization. A relatively low-cost, permanent Federal financing system could be established by setting up a revolving loan fund with one-time seed capital.

Increase Technology Demonstrations and Utility/Investor Confidence

The future electric grid will require that utilities deploy a wide range of new, capital-intensive technologies. Primary technologies are needed to support increased reliability, security, value creation, consumer preferences, and system optimization and integration at the distribution level. Demonstrating the technical readiness and economic viability of advanced technologies is needed to inspire the confidence of utilities and investors.

6. **Significantly expand existing programs to demonstrate the integration and optimization of distribution system technologies.** The complexity of the issues facing distribution systems—including new technologies, the need for systems approaches, and geographical differences in markets and regulatory structures—points to a significant need for multiple "solution sets" to enable two-way electricity flows on distribution systems; enhance value; maximize clean energy opportunities; optimize grid operations; and provide secure communications. DOE should build upon existing demonstration programs and reflect the Administration's commitment to the doubling of Federal clean energy innovation over 5 years as part of its Mission Innovation initiative. Doing so, DOE should develop a focused, cost-shared program for qualifying utilities to demonstrate advanced distribution-system technologies at the community scale. These technologies include advanced voltage control/optimization systems; dynamic protection schemes to manage reverse power flows, communications, sensors, storage, switching, and smart-inverter networks; and advanced distribution management systems, including automated substations.

   Demonstrations supported by the cost-shared, cooperative agreement program would be specifically designed to inform standards and regulations and increase regulatory and utility confidence in key technologies or technology systems. Under this program, utilities would have to make a positive business case for projects and obtain regulatory approvals for their proposed demonstrations. Preference would be given to multi-utility partnerships with diverse customer profiles and to projects that promote education and training in key academic disciplines that are essential for distribution-system transformation. Cybersecurity plans for all projects would be required and supported by programmatic review of plans and deployments.

   Existing DOE programs, including advanced distribution-management systems, microgrids, communications and sensors, storage, and cybersecurity, should be leveraged to provide technical assistance regarding technological issues, planning and performance evaluation, and institutional needs. A percentage of funding could be dedicated to small, publicly owned utilities. The program should be of sufficient size to have a material impact; it should start in fiscal year (FY) 2018 and be ramped up over the time period identified in the Mission Innovation initiative.

Build Capacity at the Federal, State, and Local Levels

The 21st-century electricity system is becoming increasingly transactive, and properly valuing attributes is key to an efficient system. Application of lessons learned that pair economic and system analysis will lead to a power system that cost-effectively serves customers while providing nationally valued public goods, e.g., reliability, resilience, and acceptable environmental performance.

Advances in electricity technologies (i.e., smart grid processes and solutions) require enhanced capabilities in human resources to ensure the cost-effective selection, deployment, and operations of key technologies.

7. **Provide funding assistance to enhance analytical capabilities in state public utility commissions (PUCs) and improve access to training and expertise for small rural electric cooperative and public power utilities.** Federal support should be provided to states and small utilities to enable them

to better manage the increasing complexities in the electricity system, such as integrating variable energy resources; incorporating energy efficiency, demand response (DR), and storage into planning; developing competencies in various technologies; and making investment and security decisions within uncertain parameters. These issues are highly technical and require a new knowledge base and skillset often within the domain of computer sciences, economics, and cybernetics. At the same time, these entities are dealing with the workforce issues of outside recruitment or retirement across the electricity industry, which QER 1.2 references. DOE should build and cultivate much-needed analytical capacity at the state level over a limited period of time by allocating funding to state PUCs to allow them to hire new or train existing analysts with more sophisticated and advanced skills and build institutional knowledge. Eligibility for state and local funding should be contingent upon demonstration of consideration for Integrated System Planning, which is outlined in this chapter. DOE should support these analysts through an online interactive education and training platform with access to nationally recognized experts. This platform would also be available and tailored to the needs of small utilities. On a national scale, these actions will serve to sustain system reliability and security and bolster resilience.

8. **Create a Center for Advanced Electric Power System Economics.** DOE should provide 2 years of seed funding for the formation of a center designed to provide social science advice and economic analysis on an increasingly transactive and dynamic 21st-century electricity system. The center should be modeled after the National Bureau of Economic Research and be managed by a university consortium. The consortium will establish and maintain a network of experts in economics, the social sciences, and the electricity system; these experts should be from academia, industry, nonprofit institutions, and the National Laboratories. The center will develop new methods where appropriate, serve as advisor and consultant to stakeholders preparing germane analyses, and foster the advancement of students and professionals who are developing expertise in these disciplines. The focus of the center will include power systems evaluation (e.g., valuation, benefit-cost, and competition analysis).

Inform Electricity System Governance in a Rapidly Changing Environment

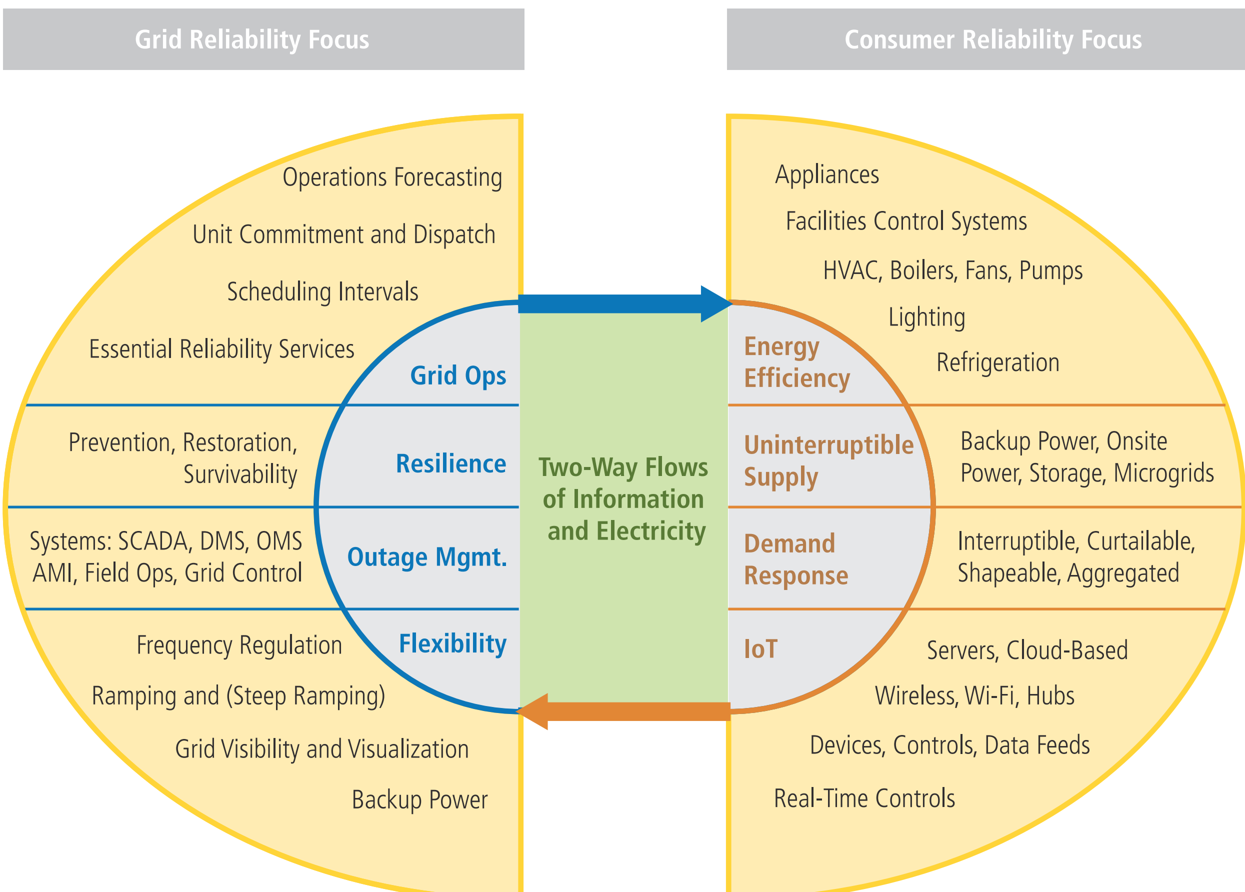
The rapid rate of change in the electricity sector today often exceeds the ability of institutions and governance structures to respond in a manner sufficient to meet critical national goals and objectives. This is particularly true in the resolution of jurisdictional disputes over responsible price formation and valuation. Clarification and harmonization of roles and responsibilities for developing pricing can reduce market uncertainty, facilitate the achievement of policy goals, and reduce costs to ratepayers.

9. **Establish a Federal advisory committee on alignment of responsibilities for rates and resource adequacy.** DOE, in collaboration with the National Association of Regulatory Utility Commissioners, should convene a Federal advisory committee that reports to the Secretary or the Secretary's designee to examine potential jurisdictional concerns and issues associated with harmonizing wholesale and retail rates and tariffs. This advisory committee will evaluate and make recommendations (where appropriate) on the way in which the organized markets reflect state policy; pricing mechanisms for maintaining resource adequacy; state and Federal roles in pricing and operation of distributed energy resources (DER), storage, and microgrids; the role of aggregators; and mechanisms for implementing consumer protection across the various markets and jurisdictions. The advisory committee will represent a broad cross-section of industry and stakeholders. An annual report will be prepared by this advisory committee for the Secretary that identifies the impact of governance issues and recommends solutions.

Maximize Economic Value and Consumer Equity

Consumer options for electricity services have grown dramatically, enabled in part by the smart grid and the IoT, and supported by significant consumer demand. New consumer options range from building efficiency technologies that reduce consumer costs for high-quality electricity services, to distributed generation (DG) technologies, to technologies for dynamic energy management. In addition to technology options, different utility business models also have a significant impact on consumer value and compensation. Utilities still provide a majority (84 percent) of the electricity supplied nationwide;[12] however, in the 16 states and the District of Columbia where retail competition is allowed, 58 percent of industrial load, 44 percent of commercial load, and 7 percent of residential load have switched to competitive energy suppliers.[13] These technologies can create value for both grid operators and consumers; adequate and accurate valuation of these new services is essential for maximizing their value. As noted in Chapter IV (*Ensuring Electricity System Reliability, Security, and Resilience*), these two-way flows are affecting both consumer demands for reliability, as well as reliability requirements for grid operations. The key components of both consumer and grid reliability are highlighted in Figure 7-5.

Figure 7-5. Electric Service Reliability Increasingly Interactive between Grid and Consumer



The development and adoption of new consumer technologies and services has dramatically outpaced those of the grid. The electricity sector is adapting to the demands placed on the grid by the two-way flows with new market structures, technological solutions, interconnection and reliability standards, and complex grid controls enabled by widespread operational data. The evolution of technologies and services on both sides of the grid will likely continue at the same or an accelerated pace. Maintaining—or increasing—grid reliability in the midst of these changes will require new approaches in both the public and private sectors.

Acronyms: supervisory control and data acquisition (SCADA), distribution management system (DMS), outage management system (OMS), advanced metering infrastructure (AMI), heating, ventilation, and air conditioning (HVAC).

The two-way flows and different expectations about reliability between consumers and grid operators can benefit both grid operators and consumers if flows are transactional and collaborative. In the alternative, two-way flows can significantly complicate grid operations. Grid operators must adapt to increased consumer options that can both positively and negatively affect grid reliability by changing their systems, processes, and technologies. Only when each group equally understands the depth of grid and consumer interdependencies can the 21st-century electricity sector be fully realized.

Tailor and Increase Tools and Resources for States and Utilities to Effectively Address Transitions Underway in the Electricity System

States and electric utilities are responsible for making critical decisions regarding how to improve the reliability, affordability, and sustainability of the electric grid; officials from state agencies and utilities provided comments as part of the QER stakeholder process on the Federal role in informing these decisions. Technical assistance, improved regional consideration in program offerings, and new analysis for decision making will allow the Federal Government to respond to the needs of states and utilities in ensuring consumer value and equity in the electricity system of the 21st century.

10. **Improve energy management and DR in buildings and industry.** Communication-capable and programmable energy-management systems that monitor and control energy-using appliances and equipment have demonstrated substantial potential to reduce both volumetric (kilowatt-hours) and peak (kilowatt) electricity demand, delivering significant economic value and service benefits to both consumers and utilities. This joint DOE-Environmental Protection Agency (EPA) initiative could further accelerate the deployment of communications-capable control systems that can deliver improved energy management and DR for residential buildings, small-to-medium commercial buildings, and comparable industrial facilities.

11. **Create a multi-sector initiative to improve efficiency of miscellaneous electric loads (MELs) through research and development (R&D), testing, labeling, targeted incentives, and minimum standards.** MELs are a broad, rapidly growing, and poorly understood group of end users, which can be addressed by building upon existing DOE and EPA efforts. Working with utilities, states, manufacturers, and other key stakeholders, this DOE, Energy Information Administration (EIA), and EPA initiative could gather data, set priorities, and take action to increase R&D, improve testing and labeling, and implement targeted incentives and minimum standards. Together these actions could improve the efficiency and management of MELs in the residential, commercial, and industrial sectors.

12. **Increase Federal support for state efforts to quantitatively value and incorporate energy efficiency, DR, distributed storage, and DG into resource planning.** DOE and EPA should leverage existing programs to provide targeted capacity building and related analytical support to states on the merits of incorporating the value of energy efficiency, DR, distributed storage, and DG in resource planning; meeting environmental goals; and extracting additional value from advanced metering infrastructure networks and resulting data and digital services.

13. **Conduct an analysis of the potential for deployment of demand side (energy efficiency, DR, DG, storage) technologies.** While numerous studies have indicated significant cost-effective potential from energy efficiency investments, there is an incomplete patchwork of different energy efficiency potential studies and other distributed resources at the utility or state level that use a variety of methodologies. These studies, which typically consider only energy efficiency, do not take into account the potential to integrate energy efficiency investments with other consumer options, such as DR, DG, and onsite storage—technologies to which consumers have growing access. DOE, with input from EPA, should conduct a study of the national potential for demand-side resources with sufficient geographic resolution to more effectively value and integrate DER into state and national electricity policy, while meeting environmental goals.

14. **Increase state-level clean energy financing.** DOE and the Department of the Treasury, in coordination with other Federal agencies, will identify promising practices in the types of state-level policies, mechanisms, and incentives that support system evolution to a cleaner grid, e.g., property-assessed clean energy (PACE) financing. These efforts will provide states with the tools and potential solutions to better leverage state resources and deploy clean energy. As part of sharing promising practices, DOE and the Department of the Treasury would help standardize contracts/financing structures for nontraditional project structures.

15. **Evaluate the potential to further increase energy savings and reduce costs to consumers and manufacturers through appliance efficiency standards.** DOE's minimum appliance efficiency standards have resulted in significant energy savings for consumers and businesses across a wide range of products. DOE, working with the Department of the Treasury and EPA, will evaluate approaches for further increasing or optimizing energy savings to consumers, while reducing costs for manufacturers and consumers.

Expand Federal and State Financial Assistance to Ensure Electricity Access for Low-Income and Under-Served Americans

Analysis indicates that electricity costs represent a disproportionate share of total income for low-income Americans. Increased funding for proven, state-administered programs and enhanced data and tools for targeting assistance can reduce this "electricity burden." Ensuring that the costs of the rapid transition of the electricity system are not disproportionately borne by low-income Americans is a top priority; low-income Americans should also be able to share in the benefits from an electricity system transition.

16. **Increase Low Income Home Energy Assistance Program (LIHEAP) and Weatherization Assistance Program (WAP) funding.** Low-income Americans in areas across the country face disproportionate burdens from electricity costs. Congress should increase Federal support for low-income home weatherization, through DOE's WAP, over the next 5 years to weatherize 100,000 homes per year, including support for training and improving auditing tools. Congress should also create a mandatory contingency funding mechanism for LIHEAP, as described in the President's FY 2017 budget.

17. **Evaluate incentives to cut electricity bills for low- and moderate-income households.** The Federal Government should improve the coordination between WAP and LIHEAP to ensure optimal use of resources and increased benefits to households served. The Federal Government should encourage state and local governments to (1) take full advantage of the use of LIHEAP funds for weatherization, (2) use the National Renewable Energy Laboratory's solar savings-to-investment ratio calculator to identify cost-effective areas for solar projects, and (3) find other ways to make it easier for low-income households to access the long-term savings possible from energy efficiency and renewable energy. In particular, DOE should evaluate the impacts of utilizing WAP and LIHEAP to decrease energy bills (i.e., from energy efficiency retrofits and installing renewable energy projects). In addition, state and local governments should ensure human services providers educate low-income clients receiving bill assistance about opportunities to save on their electricity bills through energy efficiency and renewable energy programs, and they should actively encourage participation in those programs.

18. **Strengthen incentives for public housing authorities to invest in renewable energy and energy efficiency.** Small- and medium-sized housing authorities are often unable to participate in existing energy performance contracting (EPC) options because of a lack of capital or interest from energy services companies. This project would incentivize such public housing authorities to use existing resources to make energy upgrades by allowing them to retain energy cost savings outside of an EPC contract. Congress should authorize a pilot program to allow public housing authorities to retain a greater portion of the savings realized from investments in energy efficiency and renewable energy. The

Office of Public and Indian Housing at the Department of Housing and Urban Development (HUD) would focus the pilot on strengthening incentives for housing authorities, especially smaller and medium-sized housing authorities, to invest their Capital Fund dollars in energy efficiency or renewable energy. The pilot would provide an alternative to the long-standing EPC program, which has primarily served larger housing authorities.

19. **Improve HUD data and utility benchmarking.** In order to reduce taxpayer costs on tenant utility bill allowances, Congress should enact legislation allowing HUD and property owners to access whole-building, aggregated energy consumption and expenditure data for HUD-assisted properties (i.e., whole-building utility data) and appropriate funding for HUD to implement its utility benchmarking strategy, including building out the information technology (IT) systems needed to link current systems with benchmarking software.

20. **Encourage public-private partnerships to underwrite and support clean energy access for low- and moderate-income households.** The Federal Government should align public funding programs and encourage private-sector investment to help make energy efficiency and renewable energy accessible to households that do not qualify or are unlikely to be served by WAP. The bank regulatory agencies are encouraged to publicize recently issued Community Reinvestment Act guidance concerning loans financing renewable energy or energy efficiency improvements, which help reduce operational costs and maintain the affordability of single-family or multifamily housing.

21. **Provide assistance to address rural, islanded, and tribal community electricity needs.** The Tribal Indian Energy Loan Guarantee Program provides loan guarantees for renewable energy on Indian land and is authorized under the Energy Policy Act of 2005. Indian lands have over 9 million megawatts (MW) of renewable energy potential. Because of the lack of capital, only 125–130 MW have been built. Most tribes do not meet eligibility requirements for existing loan guarantee programs. Existing rural and islanded electricity systems generally rely on imported (nonlocal) diesel fuel oil and, consequently, are high in cost and produce significant emissions. Renewable electricity generation and other electricity technologies have the potential to lower cost and reduce emissions on such systems, yet they may require new technology capabilities or significant technical expertise to successfully integrate into such systems. The Federal Government should increase support for grants and technical assistance to allow isolated communities that rely on expensive diesel-generated electricity to install more renewable energy, such as wind, small-scale hydro, or solar energy.

Increase Electricity Access and Improve Electricity-Related Economic Development for Tribal Lands

The interdependencies of electricity access, health, economic wellbeing, and quality of life underscore the importance of universal access to electricity. While recent data on electricity access on tribal lands are limited, there are still areas that lack adequate access to electricity despite the Nation's commitment to full electrification, which dates back to the Rural Electrification Act of 1936. More recent anecdotal evidence suggests that the problem broadly persists. It is a moral imperative that the Federal Government support tribal leadership and utility authorities to provide basic electricity service for the tens of thousands of Native Americans who currently lack access to electricity and to foster the associated economic development on tribal lands. Federal agencies should also support renewable energy acceleration and economic development opportunities through renewable energy incentives, workforce development, financing program improvements, and improved consultation with tribes.

22. **Support the achievement of full tribal land electrification.** Over 10 years and building upon existing programs, DOE, the Department of the Interior (DOI), and the Department of Agriculture (USDA) will provide technical assistance for distribution infrastructure with the goal of supporting tribal communities' efforts to achieve complete electrification (Indian tribes, including Alaskan Natives, on

Indian lands), while respecting the sovereignty and culture of tribal and Alaska Native communities. DOE, DOI, and USDA should support development of distribution infrastructure to provide access to household electricity and electricity distribution that enable productive economic activity and public services.

23. Support advanced technology acceleration and economic development opportunities for tribal lands. While wind energy and solar energy have grown exponentially in recent years, tribes have not been able to fully take advantage of their wind or solar resources. DOE and DOI could accelerate renewable energy development on tribal lands and economic development in tribal communities through new incentives and financing support, workforce-development resources, and enhanced consultation with tribes.

Strengthen Rural Electricity and Broadband Infrastructure

The Federal Government has historically supported the expansion of access to affordable electricity and communications service in rural America, with major initiatives continuing today mainly through USDA. The lack of access to broadband in rural areas means that these consumers lack access to DR technologies, such as smart meters, smart thermostats, and other technologies, which can reduce pollution, help consumers save electricity, improve overall grid resilience and reliability, and enhance economic development. Broadband expansion into these regions would significantly advance grid modernization goals, while providing significant communications, connectivity, and educational benefits to numerous regions of the country. Supporting broadband access in sparsely populated rural areas, many of which are low-income areas, is not, however, profitable for the private sector. Federal support would help enhance security, environmental, and economic development goals.

24. **Leverage utility broadband build-out to expand public broadband access in rural areas.** Many rural areas presently lack access to public broadband service, which is required to take advantage of these consumer smart grid technologies. The Federal Government should continue to modernize Federal programs to expand support for rural broadband, smart grid, and smart home technologies. USDA should update guidance for the Rural Development Community Facility Program to make broadband projects eligible, revise regulations to expand eligibility for the Rural Utilities Service (RUS) Telecommunications Program, and expand financing for smart grid and communications improvements for energy management in the RUS Electric Program.

25. **Increase opportunities for small and rural utilities to utilize USDA's electricity financing programs.** USDA should develop and implement a strategy to remove barriers to participation in its RUS financing program for energy efficiency and renewable energy investments, which would support Congress' intent to provide Federal financial support for ratepayers served by small and rural utilities. DOE and USDA should strengthen collaboration on strategic priorities, including developing a strategy to increase the use of USDA's financing programs by borrowers and supporting the technical needs of small and rural utilities, in part through their industry stakeholders.

26. **Improve the competitiveness of USDA's financing for small and rural utilities.** Congress should give USDA's RUS the authority to refinance its loans to small and rural utilities to stay competitive and reflect economic changes in the broader economy. Congress should undertake legislative action to unlock USDA's renewable energy financing under Section 317(c) of the Rural Electrification Act.

Enable a Clean Electricity Future

Achieving a clean, affordable, and reliable electricity sector for the 21st century is a key national objective. The transition for accomplishing this objective is complicated and will require major changes in the generation resource mix; in the valuation of key services; and in the way the grid is operated. Managing this complex set of changes while ensuring affordability, reliability, and security for electricity consumers, will require focused investments, incentives, and policies in key areas, including the following: optimizing the management of many different types of generation; enhancing the visibility, integration, and valuation of load-shaping and consumer technologies; enabling the development and diffusion of distributed and utility-scale storage technologies; managing the large-scale integration of variable energy resources and DER into grid operations; and supporting the ongoing need for dispatchable baseload generation. This transition will also require a core investment in operational and predictive analytics, including control algorithms and granular grid-visualization tools. Clean electricity options from generation to end use need to be advanced through a combination of additional research, development, and demonstration (RD&D) across the portfolio of solutions and additional policy that encourages the most cost-effective options.

Transform the Electricity System through Leadership in National Clean Electricity Technology Innovation

Private-sector investment in clean energy technology faces many barriers; for example, prices do not reflect the costs and benefits of clean energy, investments are made in a highly regulated environment, and there are high capital costs and lengthy time horizons for R&D and capital stock turnover in comparison to many other sectors (e.g., IT). Increased investments in electricity technology innovation are essential for the transformation of the electricity system. Federal investments have a history of success and have been leveraged by the private sector to create significant economic value. Case studies on nuclear energy, shale gas, and solar photovoltaic power, among many other electricity-related technologies, demonstrate the instrumental role of Federal investment in early-stage R&D.

27. **Significantly increase Federal investment in clean electricity RD&D.** The current scale and speed of clean electricity innovation is short of what is needed for meeting the Nation's clean energy and climate goals; yet, there is a series of barriers to the private sector investing adequate amounts on its own. The American Energy Innovation Council in 2010 identified specific needs for government involvement in accelerating energy innovation, and it recommended that Federal clean energy funding be more than tripled as the minimum level required to maintain America's competitive edge. Pursuant to the Mission Innovation initiative, the Federal Government should double clean energy R&D funding across all relevant Federal agencies from $6.4 billion to $12.8 billion between FY 16 and FY 21.

28. **Implement regional clean energy innovation partnerships.** Create cost-shared, technology-neutral innovation partnerships based in multi-state regions. These partnerships intend to accelerate clean energy R&D, including electricity, by tailoring project portfolios to the needs, opportunities, innovative capabilities, and intellectual and economic infrastructure of those regions. The FY 17 DOE Mission Innovation request includes initial funding of $110 million for regional partnerships.

29. **Expand clean electricity innovation analysis and tools.** Improve the data, metrics, analysis, and tools used to plan DOE's investments in clean energy innovation. Although there is substantial research on the value and impact of innovation for individual technologies, there are few robust measures and quantitative assessments of energy innovation. Enhanced energy-innovation frameworks and models that include policy interactions are needed to characterize the relationship between inputs and outputs of energy innovation, help inform investment, and deploy scarce innovation dollars.

30. **Continue reducing barriers to deploy clean energy technologies.** Since 2008, the cost of solar, wind, storage, and electric vehicle (EV) technologies has decreased by more than 50 percent. DOE should continue working to cut the costs of solar, wind, storage, and EV technologies through its world-class programs. DOE should continue work to reduce the cost of solar more than 50 percent by 2030; make EVs cost-competitive with gasoline-powered cars by 2022; decrease the price of energy storage; and develop the next-generation wind technologies, including offshore technologies and tall turbines, to expand the geographic reach of cost-competitive wind.

31. **By 2030, reduce the electricity intensity of newly constructed residential and commercial buildings by at least 50 percent relative to typical new building construction today.** Buildings, which last for decades, account for significant portions of electricity demand and greenhouse gas emissions in the United States. Ensuring highly efficient new construction will capture decades of energy savings for American families and businesses. DOE, in consultation with EPA, should set a goal, establish baselines, and scale up activities to deploy energy-efficient technologies and DER in newly constructed residential and commercial buildings.

Address Challenges to Large-Scale, Centralized Clean Generation

Regardless of the energy source, there are a number of challenges to deploying large, centralized power-generation facilities. Lower electricity prices, largely related to low-cost natural gas, are reducing the economic viability of other clean generation resources, especially nuclear energy. Nuclear power currently provides 60 percent of zero-carbon generation in the United States. Hydropower is one of the oldest and most established forms of electricity generation, contributing 6 percent of the electricity generated in the United States in 2015 and 19 percent of zero-carbon generation. Non-hydropower renewables—including wind, solar, geothermal, and biomass—accounted for about 7 percent of electricity generated in the United States in 2015. Each of these technologies faces a range of siting constraints, licensing and permitting processes, or environmental concerns, which can be broad and extensive; this can make new large-scale deployments difficult. In some cases, these deployments can take a decade or more to build. A combination of Federal coordination, licensing support, analysis of financing opportunities, and RD&D can help address these barriers.

32. **Analyze financing for advanced large-scale generation.** Alternative financing and organizational structures should be explored for advanced large-scale generation, including small modular reactors, advanced reactors, enhanced geothermal, concentrated solar power, offshore wind, and advanced carbon capture and storage projects. Many of these new, larger systems require sponsors to make significant upfront capital investments, and several also contain technology risk, which creates barriers for lenders and regulators. For example, it is currently challenging for state PUCs to allow a regulated utility to begin construction on an advanced new nuclear or carbon capture and storage plant with guaranteed rate base recovery. DOE should analyze potential opportunities to support the financing options for advanced, large-scale generation by utilities and others, building upon existing programs where applicable.

33. **Increase funding for the life-extension R&D program to ensure maximum benefits from existing nuclear generation.** The existing DOE research program to resolve technical issues with regard to subsequent license renewals for existing nuclear plants should be significantly expanded to accommodate the expected increase in renewal applications. Expansion would also enable the continued operation of existing plants through technology development, as well as improve performance and reduce costs and the use of high-performance computing to simulate reactor processes.

34. **Increase support for advanced nuclear technology licensing at the Nuclear Regulatory Commission.** Congress should provide funding to the Nuclear Regulatory Commission for the certification and licensing of advanced reactors, including the development of advanced reactor certification and licensing criteria, and processes for general public outreach, as reflected in the President's FY 17 budget proposal. In addition, Congress should authorize and fund a program at DOE to support advanced reactor license applicants, especially in the development and submission of pre-applications.

35. **Develop environmental mitigation technologies for hydropower.** Increase funding for RD&D to better understand and mitigate the environmental impacts of new and existing hydropower projects. Continued operation of some existing facilities and deployment of new facilities depend upon demonstration and acceptance of environmental mitigation technologies and strategies for facilities of all sizes.

36. **Promote responsible operation, optimization, and development of non-Federal hydropower.** Organize a national dialogue to address potential licensing and re-licensing processes that would encourage the responsible operation, optimization, and development of non-Federal hydropower in a manner that maximizes opportunities for low-cost, low-carbon renewable energy production, economic stimulation, and environmental stewardship to provide long-term benefits for the Nation.

Address Significant Energy-Water Nexus Issues Affecting—and Affected by—the Electricity System

Electricity systems and water systems are, in many cases, interconnected. Water is a critical requirement for many electricity generation technologies. Two-thirds of total U.S. electricity generation—including many coal, natural gas, nuclear, concentrated solar power, and geothermal plants—requires water for cooling. In addition, carbon capture, utilization, and storage (CCUS) technologies have significant water demands. Electricity is also required for water and wastewater conveyance, treatment, and distribution. From a full-system perspective, the joint reliance of electricity and water systems can create vulnerabilities (e.g., drought impacts on thermoelectric generation and hydropower), but it can also create opportunities for each system to benefit from well-designed integration. Such challenges and opportunities can be addressed through improved policy integration; data collection; modeling; analysis; research, development, demonstration, and deployment (RDD&D); and engagement with stakeholders.

37. **Launch an electricity-related energy-water nexus policy partnership with Federal, state, and local partners.** DOE should create an electricity-related energy-water nexus policy partnership with states, related organizations, local governments, and other Federal agencies, where appropriate; this policy partnership would discuss ways to improve and better integrate existing energy and water policies with respect to goals, data, metrics, and compliance dates. Many energy and water policies are designed to address only energy or water, but not both, potentially leading to conflicting incentives and unintended consequences that could be avoided through more integrated policy design. In support of the partnership, DOE should develop an Integration Analysis Framework to map out broad, system-wide benefits and potential vulnerabilities of energy-water systems integration (at multiple temporal and spatial scales) to inform relevant decision makers. This analysis framework would serve to enable valuation of costs and benefits associated with energy-water systems.

38. **Support additional RDD&D to reduce water requirements for carbon capture technologies.** Provide additional funding to complement existing efforts in technology RDD&D to reduce water requirements of carbon capture systems, including capture systems themselves (solvents, membranes, materials), as well as integration of the capture system with the generation plant or industrial facility. Reduced water use at power plants and other industrial facilities outfitted with CCUS would lower water withdrawal and consumption out of natural water bodies and could make CCUS technology more attractive in water-scarce areas.

Provide Federal Incentives for a Range of Electricity-Related Technologies and Systems

A package of tax incentives targeted at specific market segments can support an all-of-the-above energy strategy by helping to reduce the costs of deploying and using innovative, commercially available energy technologies. The economies of scale and "learning by doing" promoted by such deployments support continued technology cost reductions and greater market competition.

39. **Expand tax incentives for renewable electricity, EVs, and energy efficiency.** Consistent with the current Administration's Green Book proposal, expand the list of technologies eligible for Federal tax incentives to include other sources of low-carbon generation beyond wind and solar, and extend the time frame for the Production Tax Credit (PTC) and Investment Tax Credit (ITC). The PTC should also be made refundable, available to otherwise eligible renewable electricity consumed directly by the producer, and also available to individuals who install solar electric or solar water-heating property on a dwelling. In addition, implement the proposed reform to the EV tax credits and extension of commercial building energy efficiency tax credits included in the President's FY 17 budget.

40. **Extend the time frame and the total capacity allowed under the PTC for nuclear generation.** Current law provides a $0.018/kilowatt-hour PTC for new nuclear plants placed in service by 2020 and places a capacity cap of 6,000 MW. Extend the eligibility date so that reactors placed in service after 2020 could qualify and increase the capacity cap.

41. **Provide tax credits for CCUS.** Provide a tax credit, such as the proposal to create $2 billion in refundable ITCs for 30 percent of eligible CCUS equipment and infrastructure in the President's FY 17 budget; create a refundable sequestration tax credit ($10 per metric ton for carbon dioxide that is stored and reused, and $50 per metric ton for carbon dioxide that is stored and not reused); index to inflation; or implement reforms to the existing 45Q tax credit that would achieve similar goals. Expand eligibility to include industrial-sector applications of CCUS.

42. **Assess business model inequities associated with Federal electricity financial incentives and public-private partnerships.** DOE should assess the current utilization of energy tax credits by ownership type, including the impact of proposed changes to the tax code on the ability of entities to utilize incentives. DOE should also identify options to increase the impact of tax credits on the deployment of clean energy assets. Relevant topics could include the usage of tax credits by tax-exempt entities, the exclusion of ITCs from normalization, Federal financing for public power and rural electric cooperative utilities, and the possibility for expanded use of public-private partnerships.

43. **Increase power purchasing authorities for the Federal Government from 10 to 20 years.** The Federal Government is currently subject to goals and mandates for the purchase of clean energy which, if achieved, can help to catalyze action in the private, state, and local sectors. However, widespread Federal Government clean energy purchases are constrained by generally applicable procurement rules that prohibit entering long-term contracts. Congress should authorize all Federal agencies to negotiate 20-year power purchasing authorities for clean energy.

Address a Range of Power Plant Siting Issues

The land-use requirements for different types of power generation reflect significant differences between the various types of infrastructure and their operational requirements.

44. **Evaluate and develop generation-siting best practices.** DOE and DOI should initiate a 2-year series of technical workshops to evaluate generation-siting best practices, environmental impacts, mitigation options, and risk to inform decision making by developers and regulators. The workshops will draw upon state and local permitting expertise and experience. They will issue reports to provide developers and regulators tools and best practices for streamlining and potentially standardizing underlying requirements for environmental impact studies and siting analysis. Permitting of projects should continue expeditiously during this process.

45. **Support improved regional and interregional transmission planning processes.** DOE should fund the development of a systematic monitoring program to enable valuation of new transmission facilities, measure the outcomes of FERC Order Nos. 890 and 1000, and develop methodologies to improve their effectiveness. The objective of FERC Order No. 1000 is to identify methods and approaches that enable the selection of the "best" set of transmission facilities (i.e., the more efficient or cost-effective transmission facilities selected in a regional transmission plan for purposes of cost allocation). It aims to accomplish this by (1) establishing requirements for regional transmission planning and interregional transmission coordination processes, and (2) opening transmission investment to non-incumbent owners. However, because implementation of FERC Order No. 1000 is in the early stages and no systematic monitoring system is in place, it is not possible to assess whether its requirements are having their intended effects. Success would mean that transmission planning and cost allocation would be effectively supporting transmission, while also reducing costs, sustaining or improving reliability, reducing congestion, and/or meeting transmission needs driven by public policy requirements.

46. **Modernize electricity transmission permitting procedures.** DOE should expand the domestic coverage of its Regulatory and Permitting Information Desktop (RAPID) Toolkit, which contains information related to critical state requirements. The Toolkit should be updated to include the 36 states that currently have no transmission-related information in the Toolkit. This would provide support for the Federal Permitting Improvement Steering Council, which was tasked with modernizing Federal infrastructure permitting to create efficient project delivery and improve outcomes. One step in reducing complexity is providing developers, government agencies, tribes, and other affected entities access to information relating to Federal and state policies and requirements that would expedite their involvement.

Ensure Electricity System Reliability, Security, and Resilience

System reliability has been an essential expectation of electricity consumers since the development of the modern electricity system. Reliability is formally defined through metrics describing power availability or outage duration, frequency, and extent of the outage. The utility industry is primarily responsible for ensuring system reliability through risk-management strategies to prevent disruptions from reasonably expected hazards. Risk-management practices need to keep pace with the emerging threat environment, particularly cybersecurity and severe weather associated with climate change. The grid's growing interconnectedness and incorporation of new energy resources also create new risks and vulnerabilities, even as they create significant new value to all users of the electricity system.

For these reasons, the traditional definitions of reliability alone may be insufficient to ensure future system integrity and available electricity services. U.S. policies, markets, and institutional arrangements must evolve to reflect this new reality. Actions and approaches are needed to integrate resilience concerns into system planning and reliability standards, prioritize investments in reliability and resilience, quantify the benefits of investments that address emerging or low-probability hazards, broaden the range of risk-reduction options, improve flexibility through activities both pre- and post-disruption, and ultimately, focus on maintaining and improving energy delivery outcomes for the customer under all conditions.

A focus on evolving hazards, new metrics, better analysis, finer data granularity, and strong interdependencies between grid operators and consumers frames the scale and scope of necessary sector transformation. These challenges could be mitigated through a combination of standards, risk-management methods and processes, and collaboration across industry, state, local, and Federal stakeholders.

Support Industry, State, Local, and Federal Efforts to Enhance Grid Security and Resilience

Some types of extreme weather events are projected to increase in frequency and intensity. Cyber threats to the electricity system are increasing in sophistication, magnitude, and frequency. Physical threats remain a concern. These challenges could be addressed through a combination of cost-benefit analyses, standards, and collaboration across industry, state, local, and Federal stakeholders. The following recommendations build upon and extend current initiatives, such as DOE's Grid Modernization Initiative and Partnership for Energy Sector Climate Resilience.

47. **Develop uniform methods for cost-benefit analysis of security and resilience investments for the electricity system.** DOE should develop methods for calculating the costs and benefits of investments in resilience solutions, as well as methods for managing the risks associated with many types of high-impact, low-frequency events or emerging and rapidly evolving threats related to climate change, cyber or physical attacks, or combined threats. This could be implemented in part through the establishment of a "community of practice" for valuation of electricity sector reliability and resilience, providing a stakeholder forum for sharing current practices and developing uniform valuation methods.

48. **Provide incentives for energy storage.** Provide a financial incentive to reduce the cost and support deployment of non-emitting energy storage. Qualified storage includes equipment that receives, stores, and delivers energy using batteries, compressed air, hydrogen storage (including hydrolysis), thermal energy storage, regenerative fuel cells, flywheels, capacitors, superconducting magnets, technologies, and systems that provide the verified services and benefits or technologies.

49. **Improve and upgrade existing Federal hydropower operations.** Fifty percent of U.S. hydropower is Federally owned. DOE, the Army Corps of Engineers, and the Bureau of Reclamation should convene relevant stakeholders to identify and discuss opportunities to improve existing Federal hydropower. Relevant topics to address include technology upgrades; increases in generation, capacity, and essential reliability service capabilities; operations and maintenance efficiency; acquisition improvements; funding flexibility; and mitigating impacts from hydropower.

50. **Account for emerging threats in reliability planning.** Reliability standards and planning requirements should be updated to increase electricity sector resilience to emerging and rapidly evolving hazards, like climate change and cyber and physical threats. The Federal Government should take formal steps to update reliability planning standards for the bulk power system. States, cooperatives, and public power should update or establish new requirements for resource planning and other planning processes for distribution systems. States should also update design standards for critical infrastructure and annually update Energy Assurance Plans accordingly. Similarly, standard-making organizations (e.g., the American National Standards Institute and the Institute of Electrical and Electronics Engineers [IEEE]) should take steps to evaluate whether new performance standards and testing procedures are needed to ensure that electrical equipment is resilient to rapidly evolving hazards.

51. **Support grants for small utilities facing cyber, physical, and climate threats.** Small utilities cover over 75 percent of the Nation's landmass, including sensitive and military installations.[a] The combination of large service territories, minimal staffing, limited budgets, lack of access to tax incentives, and low

[a] Although such facilities frequently have backup power capabilities, the durability of such backups is typically limited to fuel supplies on hand.

customer density presents challenges to small utilities addressing such new and evolving threats. DOE and USDA's RUS should work together to develop risk-management tools, provide grants for shared staff to implement solutions (such as through joint action and/or generation and transmission programs), and host workshops to facilitate knowledge transfer to support small utilities as they address these challenges.

52. **Support mutual assistance for recovering from disruptions caused by cyber threats.** Utilities have a long history of providing mutual assistance in the event of traditional disruptions, but as the grid becomes more reliant on digital technology, cyber and cyber-physical threats present new and distinct challenges to system restoration. DOE, in coordination with interagency partners and industry, should increase support for private-sector efforts to respond to significant cyber incidents on the electric system.

53. **Support the timely development of standards for grid-connected devices.** Common interoperability standards are critical to enabling the distribution system to accommodate the growth of grid-connected technologies at large scale and to potentially improve grid cybersecurity. DOE should work with the National Institute of Standards and Technology to increase the pace of standards development so that it aligns with the rapid development and deployment of grid-connected devices.

54. **Support development of an enhanced reliability service class for commercial customers.** When there is a power failure, a new and growing class of commercial customers lose significant economic value immediately. The electricity demand of individual commercial customers is of insufficient scale, however, to support options similar to those of large industrial customers, who can pay their utilities to install additional feeders to enhance service reliability. This lack of scale and rate options has led some commercial customers to pursue third-party options (e.g., storage, backup generators, onsite generation) to improve their electricity reliability. Associated grid defections could affect the overall customer and rate base. Analysis is needed to inform new rates for this class of customers. DOE should encourage states to consider having utilities offer enhanced reliability through commercial service packages that provide reduced outages, higher reliability, and quicker recovery for interested customers.

55. **Improve system reliability through analysis of backup-generation best practices.** Many industrial, commercial, and residential customers utilize onsite backup power generation during electricity disruptions. There have, however, been several high-profile failures of backup generation that have had significant impacts on consumers and businesses. Also, as load management grows in importance, so does the visibility of the level and reliability of backup generation, as well. Finally, key lifeline infrastructures and defense facilities depend on backup generation. DOE should conduct a nationwide study of backup generation; it should specifically identify related gaps and critical needs for consumers, critical infrastructure, and sensitive facilities. This analysis should further consider interconnection approaches for backup generation to improve overall system resilience and reliability through the update and adoption of IEEE 1547 interconnection standards. This analysis should also take into account cost-effectiveness and environmental performance. DOE should consider the outcomes of this analysis and provide recommendations on best practices for backup generation and on how to maximize its value for grid operations, lifeline networks, and consumers.

56. **Develop guidance, best practices, and protocols for select categories of distribution equipment and consumer grid-interactive devices.** Distribution system-wide outages could be induced by disrupting interconnected DER and their associated data feeds to the distribution grid, especially during critical peak demand or by causing lasting damage to a distribution transformer. DOE will do this in coordination with the National Institute of Standards and Technology and industry.

57. **Require states to consider the value of DER, funding for public purpose programs, energy and efficiency resource standards, and emerging risks in integrated resource or reliability planning under the Public Utility Regulatory Policies Act (PURPA).** PURPA section 111(d) establishes Federal standards for regulated electric utilities that State public PUCs "must consider." Because rates of distribution utilities are not directly regulated by the Federal Government, PURPA amendments serve to preserve the legal authority of the states to amend or establish new standards. Without statutorily dictating any final state decisions, Congress should amend PURPA to require state PUCs and nonregulated utilities to consider the following: (1) the costs and benefits of DER and alternatives in rate design and integrated resource planning, (2) stable funding for public purpose programs, (3) energy efficiency resource standards, and (4) emerging risks in integrated resource or reliability planning.

Improve Data for Grid Security and Resilience

As the Nation increasingly relies on electricity to power the economy and support consumer options and choices, the consequences of electricity outages are rising. The United States currently lacks sufficient data on all-hazard events and losses. Such data would help utility regulators, planners, and communities analyze and prioritize security and resilience investments.

58. **Establish Federal standards for maintaining and sharing common data on Presidentially declared natural disasters and physical attacks affecting the electricity system.** DOE and the Department of Homeland Security should improve the collection, curation, and accessibility of data related to the impacts of disasters along with detailed characterizations of the nature and cause of each disaster. By improving the availability and quality of historical disaster impact data, the government and its partners can develop improved risk models, as well as gain the ability to more effectively locate and more clearly understand points of vulnerability within existing systems. Defining data standards would increase the ability of Federal agencies to manage and share disaster impact data by making it possible to merge and query disparate data sets by common feature, such as Presidential disaster declaration number. Types of data that would be more readily available as a result of this effort include detailed characterization of the nature and cause of each disaster, as well as the extent and degree of associated impacts (such as power outages, fatalities, injuries, property losses), and other data to inform decision making that will help communities better prepare for and respond to future disasters.

59. **Enhance coordination between energy-sector information sharing and analysis centers and the intelligence communities to synthesize threat analysis and disseminate it to industry in a timely and useful manner**. The nature of cyberspace and its associated threats requires individuals, organizations, and the government to actively participate in incident response activities. Increased coordination would provide deeper analysis of threats based on both classified and unclassified data available from the operational and enterprise environments.

Encourage Cost-Effective Use of Advanced Technologies that Improve Transmission Operations

Permitting and planning are necessary but complex processes that can slow transmission development and increase costs. Other barriers restrain the use of new technologies that can increase transmission system-capacity utilization and improve reliability and security, as well as other planning priorities.

60. **Promote deployment of advanced technologies for new and existing transmission.** DOE should work with stakeholders to identify, analyze, and develop recommendations for removing barriers to the valuation and deployment of advanced technologies for new and existing transmission, such as those that enhance reliability, security, and affordability through visibility and control. DOE should explore a range of legislative and regulatory options and analytically test their potential effectiveness on both a stand-alone basis and a collective basis to enable deployment of technologies that cost-effectively

increase existing transmission-capacity utilization (i.e., remove barriers to technology solutions that enable greater transmission utilization of existing transmission capacity). In addition, DOE should identify and mitigate barriers to technologies that can increase transmission-capacity utilization and create a framework for future work based on the experiences of work in capacity utilization, synchrophasors, and storage.

Improve EIA's Electricity Data, Modeling, and Analysis Capabilities

EIA provides all levels of stakeholders—government, companies, and customers—with data to inform the evaluation and development of policies that affect the electricity grid. More timely and publicly accessible data on how system operations are changing and on how efficiency and renewable energy are specifically affecting them would facilitate the development of Federal and state policies and investments needed to ensure the reliability, resilience, and security of the grid. Substantially improved electricity transmission data and related analyses by EIA would support significant improvements in the effectiveness of a broad range of government policies and programs, including market design and transmission planning.

61. **Expand economic modeling capability for electricity.** EIA should be able to more accurately reflect the role of energy efficiency, DR, electricity storage, and a variety of DG technologies in current and future energy consumption to better inform investments and modeled policy scenarios.

62. **Expand EIA data collection on energy end uses.** EIA should expand the scope and frequency of its data collection on energy end uses and services in the residential, commercial, and industrial sectors, including the use of new data-collection methods and tools, in order to enable a more detailed representation by region, income, and other characteristics.

63. **Expand EIA hourly data collection on power system operations.** EIA should expand the scope of the current grid operations data collection to require (1) net generation by energy source (e.g., coal, solar, wind, natural gas, nuclear) and (2) subregional detail for large balancing authorities in order to inform investment decisions and provide higher-resolution and more quickly delivered data on how system operations are changing. EIA should continue to evaluate new definitions for National Energy Modeling Systems Electricity Market Module.

64. **Expand EIA data collection on electricity transmission.** EIA should improve the scope, frequency, and resolution of transmission data collection by (1) developing a regional transmission organization/independent system operator dashboard on the operation of centrally organized, wholesale power markets; (2) collecting and maintaining information on the utilization of the bulk transmission system that complements current data collection; and (3) improving reporting on transmission investment and on the functioning and outcomes of transmission planning activities, to enable analysis on whether transmission policies and regulations are achieving their intended effects. All proposed activities should be undertaken through processes that comply with existing data-collection protections.

65. **Support EIA's collection of additional data on electricity and water flow for water and wastewater utilities.** Electricity usage in delivering water services represents a significant portion of U.S. electricity consumption (estimated at 3 to 4 percent of total electricity consumption) and may present major opportunities for both efficiency and renewable generation; however, EIA does not currently collect this data in its surveys. EIA should expand its data collection to include annual electricity and annual water flow (millions of gallons) by water and wastewater utilities, in order to enable identification of new opportunities for electricity use and savings.

Electricity Workforce of the 21st Century: Changing Needs and New Opportunities

Support the Electricity Sector Workforce

The electricity sector is undergoing a number of significant shifts in structure, energy sources, and applications as the industry modernizes and evolves. The full potential of these shifts will, however, only be realized if the electricity sector workforce appropriately adapts and grows to meet the needs of the 21st-century electricity system. The Federal Government has an interest in the development of this workforce.

66. **Support cyber-physical systems (CPS) curriculum, training, and education for grid modernization and cybersecurity.** The December 2010 report of the President's Council of Advisors on Science and Technology, titled "Designing a Digital Future," highlighted the unique importance and challenges of CPS, such as the power grid. One of the challenges with such systems is the lack of a dedicated and trained, cross-disciplinary workforce skilled at comprehending, designing, and managing CPS. This presents an acute challenge in the realm of power-sector cybersecurity, where cyber and cyber-physical threats are presenting new and distinct challenges. Prevention, mitigation, and response and recovery efforts require a workforce that understands the unique electric sector IT and operational technology systems and challenges; however, the industry currently faces a shortage of such workers. The Federal Government—through the Department of Education, DOE, National Science Foundation, and others—should sponsor development and deployment of CPS and cybersecurity educational curricula with community colleges, universities, and institutions of higher education to meet the grid-modernization needs of the 21st-century electricity system; they can do this by offering grants and supporting programs for educational institutions to develop and deploy CPS and power-sector cybersecurity educational curricula.

67. **Enhance and align skills-based training and electricity sector workforce development.** The Federal Government has multiple resources that help address the difficulty employers are experiencing in hiring skilled workers in the electricity sector. To facilitate access to these Federal programs, the following steps should be taken:

    - DOE should, with other Federal agencies (e.g., the Department of Labor [DOL], National Science Foundation, Department of Commerce, Department of Education, and Department of Defense), coordinate Federal initiatives on electricity sector education and training, including programs to facilitate national training credentials in new electricity technologies.
    - DOL should expand its pre-apprenticeship programs.
    - DOE should expand its existing programs to increase the number of internships, fellowships, traineeships, and apprenticeships.
    - DOE, DOL, and the Department of Defense should work together to create workforce opportunities for veterans, to build a more inclusive workforce, and to bring clean energy job training to low- and moderate-income communities.
    - DOL and DOE should develop a single resource web portal to inform industry and potential employees about the multiple Federal agency workforce development initiatives and resources.

68. **Support Federal and regional approaches to electricity workforce development and transition assistance.** Changes in the electricity sector are increasing the need for a diverse and specialized workforce. To ensure electricity sector workers maintain the capabilities required to provide for reliable and affordable electricity in a rapidly changing environment, DOE (in partnership with other agencies) should facilitate programs and regional approaches for workforce development. Federal funding and technical support should enhance existing programs on workforce diversity; apprenticeship and apprenticeship-readiness programs; skills-based training and education; transition assistance; and curriculum development. Workforce assessment tools should be developed to complement training programs. Federal agencies should coordinate their efforts through the interagency Energy and Advanced Manufacturing Workforce Initiative, staffed by DOE. Unemployed workers nearing but not yet eligible for retirement may have difficulty retraining after careers built on specialized skills that are no longer in demand in the modern electricity industry. Retirement-transition assistance should be provided to these workers. Where possible, Federal agencies should leverage existing government, nongovernment, labor, and industry workforce consortia.

Meet Federal Commitments to Communities Affected by the Transformation of the Electricity Sector

To achieve the transition to the electricity sector of the 21st century smoothly, quickly, and fairly, the Federal Government should offer a synthesized package of incentives that address the needs of the most important stakeholders both within and outside the electricity sector. Many of these needs are addressed through other recommendations on this list, including incentives to reduce the cost of flexible and clean assets, encourage the deployment of new and improved technologies throughout the electricity supply chain, and train workers for 21st-century electricity jobs. Recognizing that the shift to the 21st-century electricity system can impact communities that depend on 20th-century resources, the following recommendations provide transition assistance for communities affected by the multi-decadal decline in coal production.

69. **Fulfill Federal commitment to fund coal miner retiree benefits.** Over the last 50 years, coal miners have repeatedly foregone increases in wages in exchange for pension and healthcare benefits. These benefits are now imperiled by (1) the recent bankruptcy of three of the largest public coal companies in America—allowing those companies to avoid fully funding their employees' benefit funds—and (2) the declining ratio of active contributing workers relative to beneficiaries in the health and pension funds. Recognizing the commitments to support coal miner retirement benefits made by the Federal Government in the 1946 Krug-Lewis Agreement, the 1992 Coal Industry Retiree Health Benefit Act, and the 2006 amendments to that act, and also recognizing the contribution that coal miners have made to the U.S. economy, the Administration strongly supports legislation that would transfer funds to the largest multi-employer health and pension fund serving retired coal miners and their families, thereby ensuring that it can continue paying benefits.

70. **Meet the Federal commitment to appropriate sufficient funding to accomplish the mission of the Abandoned Mine Lands (AML) Fund.** DOI's Office of Surface Mining Reclamation and Enforcement estimates that there are more than $4 billion worth of high-priority, health- and safety-related, abandoned coal mine lands in the United States. At the same time, the AML Fund has an unspent balance of $2.5 billion dedicated to reclaiming these sites. The AML fees should be returned to their original 1977 levels to raise additional reclamation funds, and disbursements from the AML Fund should be accelerated over the next 5 years, enhancing economic development in distressed coal communities through reclamation employment.

Enhancing Electricity Integration in North America

Increase North American Cooperation on Electric Grid and Clean Energy Issues

Cooperation on electricity is needed to strengthen the security and resilience of an integrated, cross-border electricity grid, as well as to provide increasing amounts of clean energy and improve economic competitiveness across North America. A clear understanding of the regulatory requirements at the Federal and state levels for the permitting of cross-border transmission facilities, a sharing of best practices, and an exploration of potential future cooperation on grid-management issues will limit uncertainties and improve policy coordination at the multilateral and international levels. This includes implementing the target established in the 2016 North American Leaders Summit to increase clean power to 50 percent of the electricity generated in North America by 2025.

71. **Increase U.S. and Mexican cooperation on reliability.** In 2005, the United States and Canada codified an international reliability framework based on an electricity reliability organization. As Mexico moves ahead with electricity reform and looks to expand their electricity system (including planning for international transmission), an international commitment to reliability would signal good progress toward improved electricity system management across North America. A commitment to working jointly on reliability was also included in the statement from the North American Leaders Summit in June 2016, where these leaders "committed to deepened electric reliability cooperation to strengthen the security and resilience of an increasingly integrated North American electricity grid."[14] The U.S. Government should increase cooperation on reliability between the United States and Mexico by establishing bilateral reliability principles between the United States and Mexico.

72. **Advance North American grid security.** In December 2016, the United States and Canada released a Joint United States–Canada Grid Security Strategy framing how these two countries plan to work together to strengthen the security and resilience of the electric grid. This plan included strategy against the growing threat from cyber attacks and climate change impacts. This recommendation aims to complete that objective through the sharing of best practices and exploration of potential future cooperation on grid security issues with Mexico, in parallel with implementation of the Joint United States–Canada Grid Security Strategy and domestic Action Plans.

73. **Promote North America clean energy infrastructure development by sharing best practices for community engagement.** Lessons learned from sharing across regional entities can be a challenge, but the Federal Government can provide a forum for that engagement. This recommendation proposes that the U.S. Government initiate a series of high-level meetings with Canada and Mexico to share best practices relating to community engagement for clean energy infrastructure development throughout North America.

74. **Promote permitting of cross-border transmission facilities.** The "Regulatory Side-by-Side Governing Permitting of Cross-Border Electricity Transmission Facilities between the United States and Canada" summarizes existing regulations as of the time of publication. The document has proved incredibly useful as a resource for other analytical efforts and in informing discussion about simplifying or harmonizing regulations. Expanding this work to Mexico as the energy reforms move ahead would be very helpful to developers and governments. In addition, high-level meetings to improve community engagement for infrastructure can be supported by an effort at DOE with partners in Canada and Mexico to complete and update the Regulatory Side-by-Side and expand the RAPID Toolkit to the North America cross-border context. Consistent with the "North American Climate, Clean Energy, and Environment Partnership Action Plan," DOE should promote permitting of cross-border transmission facilities by expanding the

RAPID Toolkit. Expansion of this toolkit will enable a clear understanding of the regulatory requirements at the Federal and state levels for the permitting of cross-border transmission facilities, in addition to those for bulk transmission.

75. **Modernize international cross-border transmission permitting processes.** Building upon Executive Order 13604, "Improving Performance of Federal Permitting and Review of Infrastructure Projects," a 2013 Presidential Memorandum titled "Transforming our Nation's Electric Grid through Improved Siting, Permitting, and Review" aims to modernize transmission permitting processes. The Presidential Memorandum directed Federal agencies to create the integrated interagency pre-application process (IIP) across the Federal Government (1) to help identify and address issues before the formal permitting process begins and (2) to improve coordination of permitting across Federal, state, and tribal governments. On September 21, 2016, DOE's Office of Electricity Delivery and Energy Reliability announced a final rule for the IIP. The IIP process encourages robust early coordination prior to the submission of a formal transmission permit application. That includes increased engagement with DOE as a coordinating agency, as well as relevant state, local, and tribal stakeholders. The principles of the IIP have already been successfully applied to two existing and recent Presidential permit applications for clean energy transmission. Building on these activities, DOE should modernize international cross-border transmission permitting processes by implementing a pre-application process and update the Presidential Permitting rules.

76. **Increase North American clean energy and technical coordination.** Technical discussions have the potential to support better coordination on clean energy and climate goals, primarily through the creation of more robust North American modeling capabilities and wider accounting of clean energy and carbon emissions associated with cross-border trade. Technical discussions can also continue and enhance cooperation on energy information exchange across North America. In addition, technical discussions should focus on increasing North America wholesale electricity markets' cooperation by sharing best practices for market development. As North America moves toward greater integration, there should be continued engagement on the cross-border impacts of climate and clean energy policies in order to limit uncertainties and improve policy coordination at the multilateral and international levels. There is a need for analytical tools and models that can estimate the value of technology deployment and summarize the impacts of policies in the clean energy and climate policy space. Specifically, models and studies are needed to examine (1) policy levers and incentives for clean energy and technologies to achieve climate goals; (2) the emissions impacts of jointly planning climate action and policies for climate and clean energy; (3) the impacts of cross-border trading on clean energy development, emissions, and the electricity system; and (4) the impacts of market policies, including cross-border trading schemes for carbon and emissions. With new modeling capabilities and through technical discussions, DOE should explore the impact of enhanced cross-border trade on greenhouse gas emissions, economic development (in all countries, and collectively), as well as system reliability. Specific analysis could model market structures and examine the interplay between short-term operational flexibility and long-term financial certainty; examine the impact of enhanced U.S. imports of Canadian hydropower on carbon emissions and U.S. renewable energy development; examine best practices for the development of wholesale electricity markets; study Mexico's integration into the Western Climate Initiative; and explore impacts on the U.S. renewable energy industry, end-use costs for consumers, and the impacts of adjustments in subnational policies on clean energy consumption across the continent.

Conclusion

The electricity sector has been, and will continue to be, an indispensable tool to enable the United States to meet its linked national goals. Thanks to technology innovation and more than a century of development, the electricity system is already an extraordinary national asset. It has supported significant progress toward economic prosperity, equity, environmental responsibility, and security and resilience. The QER 1.2 identifies many approaches that can build on this success to advance—and accelerate—the electricity system's role in meeting these goals.

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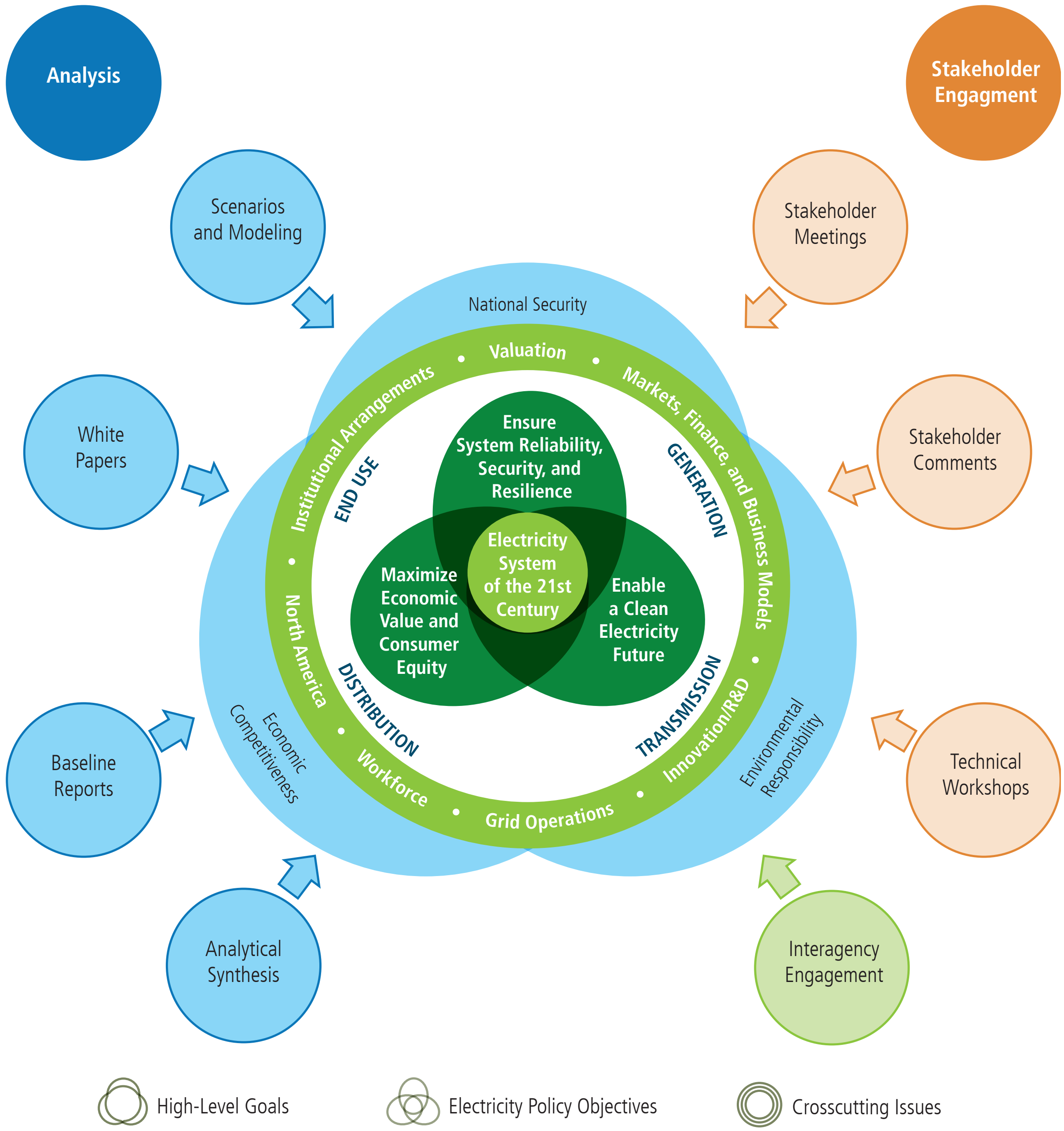
Chapter VIII

ANALYTICAL AND STAKEHOLDER PROCESS

This chapter describes the analyses and stakeholder engagement process that provided the substantive basis for this second installment of the Quadrennial Energy Review (QER 1.2). The first section describes the analytical work carried out for the QER 1.2, including baselines, models, topical reports, and white papers. The second section describes how the QER 1.2 process included engagement with a broad range of stakeholders across the Nation, through technical workshops, seven formal public stakeholder meetings, and the collection and consideration of public comments. This chapter is intended to document the process of developing the QER 1.2 and to provide transparency on the methods used to develop the material in the report.

Figure 8-1. Inputs to QER 1.2



This figure shows the analytical, stakeholder, and interagency efforts underpinning the QER 1.2.

Systems Analysis

The Administration-wide Quadrennial Energy Review (QER) is intended to enable the Federal Government to translate policy goals into a set of analytically based, integrated actions over a 4-year planning horizon. The White House Domestic Policy Council and Office of Science and Technology Policy jointly chair the interagency QER Task Force, while the Secretary of Energy provides an Executive Secretariat in the Department of Energy's (DOE's) Office of Energy Policy and Systems Analysis (EPSA). The QER involves a multi-agency review process, and more than 20 executive departments and agencies[a] play key roles in developing and implementing policies proposed in the QER. Unlike other Federal quadrennial review processes where analysis is done every 4 years, the QER is conducted through installments to allow for granular analysis of key energy subsectors. Serving as Secretariat, EPSA is responsible for coordinating activities related to the preparation of the report, including commissioning an extensive suite of policy analysis focused on the electricity system (Figure 8-1).

QER 1.2's analysis was completed over many months through the following methods:

- Commissioning five baseline reports to provide an overview of the current state of the electricity system
- Commissioning analyses, modeling, synthesis, and white papers from U.S. National Laboratories, energy consultants, and analytics firms
- Convening technical workshops with relevant stakeholders and producing write-ups of findings and stakeholder viewpoints
- Performing analysis and modeling within EPSA, in collaboration with partners across DOE and other Federal agencies, to generate analysis, policy working papers, and reports
- Meeting with EPSA and staff-level agency representatives and experts on the findings and recommendations proposed in QER 1.2.

Crosscutting Analysis

This section provides examples of major external analyses commissioned by EPSA that support the findings and recommendations within QER 1.2. The descriptions below categorize the analyses (with the caveat that most QER 1.2 analyses are crosscutting in nature and apply to more than one energy objective or sector).

Baselines

A series of EPSA baselines were developed to provide an overview of elements of the electricity system. These baselines helped inform QER 1.2 and focused on the following issue areas: generation, distribution, end use, markets, and climate and environment.[b] These baseline analyses identify major historical trends in the electricity sector and reflect the workings, characteristics, and issues of the current electricity system. These baselines provide a foundation for the analysis of systems and policy recommendations that form QER 1.2.

[a] The members of the Task Force include: (1) the Department of State; (2) the Department of the Treasury; (3) the Department of Defense; (4) the Department of the Interior; (5) the Department of Agriculture; (6) the Department of Commerce; (7) the Department of Labor; (8) the Department of Health and Human Services; (9) the Department of Housing and Urban Development; (10) the Department of Transportation; (11) the Department of Energy; (12) the Department of Veterans Affairs; (13) the Department of Homeland Security; (14) the Office of Management and Budget; (15) the National Economic Council; (16) the National Security Staff; (17) the Council on Environmental Quality; (18) the Council of Economic Advisers; (19) the Environmental Protection Agency; (20) the Small Business Administration; (21) the Army Corps of Engineers; (22) the National Science Foundation; and (23) such agencies and offices as the President may designate.

[b] The environmental baseline was divided into four volumes in the following categories: Greenhouse Gas Emissions, Solid Waste and Decommissioning, Energy-Water Nexus, and Environmental Quality.

Key Reports and Studies

QER 1.2 drew from multiple studies of the electricity system, including but not limited to the following:

Table 8-1. List of Chapter-Specific Analyses for QER 1.2[c]

Title	Performer
Context and Scope	
Accelerate Energy Productivity 2030	NREL
Principles for Creating and Evaluating Electric System Reliability Plans in the 21st Century	NREL, PNNL, ORNL
Cyber Threat and Vulnerability Analysis of the U.S. Electric Sector	INL
Energy Supply Chain Vulnerabilities: Framework and Case Study	ANL, ORNL, INL
Modernizing the Electric Distribution Utility to Support the Clean Energy Economy	EPSA
Harmonizing the Electricity Sectors across North America	RFF
Electricity Distribution System Baseline Report	PNNL
Electricity Generation Baseline Report	NREL, INL, NETL
Residential Electricity Bill Savings Opportunities from Distributed Electric Storage	EPSA
Establishing the Playing Field: Surveying Clean Energy-Related Economic Development Policy across the States	NREL
Security, System Resilience, and Reliability	
Assessing Cost and Benefits of Investments in Climate Resilience	ORNL
Utility Risk-Mitigation Strategies	Deloitte
Scoping Analytical Tools and Methods for Vulnerability Analysis of Linked Electric Generation and River Basin Systems	ORNL
Guide to Cybersecurity, Resilience, and Reliability for Small and Under-Resourced Utilities	NREL
Resilience of the U.S. Electricity System: A Multi-Hazard Perspective	ORNL, LANL, ANL, SNL, PNNL, BNL
Front-Line Resilience Perspectives: The Electric Grid	ANL
Clean Electricity Future	
Energy Efficiency under Alternative Carbon Policies: Incentives, Measurement, and Interregional Effects	NREL
Evaluating the CO_2 Emissions Reduction Potential and Cost of Power Sector Re-Dispatch	NREL
Literature Review of Studies That Include an 80% Reduction in GHGs by 2050	Energetics
Characterizing Energy Efficiency in Low-Income Communities	LBNL
Environment Baseline Vol. 4: Energy-Water Nexus	EPSA
Advanced Water Metering Infrastructure	NREL, INL, NETL

[c] Acronyms used in Table 8-1 include the following: NREL – National Renewable Energy Laboratory; PNNL – Pacific Northwest National Laboratory; ORNL – Oak Ridge National Laboratory; INL – Idaho National Laboratory; ANL – Argonne National Laboratory; EPSA – Office of Energy Policy and Systems Analysis; RFF – Resources for the Future; NETL – National Energy Technology Laboratory; LANL – Los Alamos National Laboratory; SNL – Sandia National Laboratories; BNL – Brookhaven National Laboratory; CO_2 – carbon dioxide; GHGs – greenhouse gases; LBNL – Lawrence Berkeley National Laboratory.

Title	Performer
Economic Value and Consumer Equity	
Energy Tax Policy	EPSA
Characterization of Regional Electric Markets	Pace Global
Review of the Economics Literature on U.S. Electricity Restructuring	University of California, Davis
DER and Rate Financial Analysis	EPSA
Recovery of Utility Fixed Costs: Utility, Consumer, Environmental, and Economist Perspectives	LBNL
Fixed-Cost Allocations and Rate-Making Instruments to Address Distributed Energy Resources	EPSA

The QER commissioned multiple studies across the electricity system, including but not limited to these reports for specific chapters.

Technical Workshops

As part of the crosscutting analysis conducted for QER 1.2, the QER Task Force flagged some topics deemed particularly complex for technical workshops to discuss further with stakeholders and industry experts. Technical workshops convened subject matter experts and relevant stakeholders to provide expert insights on various elements of the electricity system through the intensive analytical approach of these 1-day and 2-day symposia. Each technical workshop featured a roster of subject matter experts from industry, academia, the National Laboratories, and other relevant organizations.

Below are details about the topics, dates, and locations of the technical workshops that DOE held to inform QER 1.2:

Technical Workshop on Electricity and Information and Communication Technologies Convergence
June 15, 2015 – Washington, D.C.

DOE hosted a technical workshop to understand stakeholder issues on electricity and information and communications technology (ICT). The workshop sought to inform the completion of the Pacific Northwest National Laboratory white paper commissioned by DOE: *The Emerging Interdependence of the Electric Power Grid and Information and Communication Technology*. The second focus of the workshop was to elicit additional electricity and ICT research and policy analysis topics for potential examination within DOE. The workshop included participants from utilities, industry stakeholders, energy associations, and regulators.

The goal of this meeting was to leverage the inherent synergies between DOE's research and policy functions and gather expert input. Specifically, this workshop concerned the current status of deployment of electricity and ICT infrastructure, as well as trends and developments in market places, technologies, and regulations.

Electric Power in the United States and Canada: Opportunities for Regulatory Harmonization
October 20, 2015 – Boise, Idaho
October 27, 2015 – Albuquerque, New Mexico

DOE sponsored a workshop hosted by Resources for the Future—in concert with the International Institute for Sustainable Development and Boise State University—looking at the electricity sectors in the United States and Canada. The workshop had several purposes: (1) to identify gaps, best practices, and inconsistencies with regulations and electricity system planning across the United States, Canada, and Mexico; (2) to inform the creation of legal, regulatory, and policy roadmaps for harmonizing regulations and planning; and (3) to bring together individuals who can help implement greater harmonization. The two workshops examined policies, regulations, and planning associated with the electricity sector, and within that sector, environmental regulations (for air pollution, greenhouse gases [GHGs], and renewables). They also examined the regulations and processes associated with the operation and planning of the electricity system—including generation and transmission. DOE and Resources for the Future published a final paper summarizing the recommendations and observations of workshop participants in early 2016.

Low-Carbon Futures of the U.S. Energy System
January 14, 2016 – Washington, D.C.

In 2009, and subsequently in 2014, the Administration set GHG-emissions reduction targets in the range of 17 percent below 2005 levels by 2020 and 26 to 28 percent below 2005 levels by 2025. Both of these goals are intended to put the United States on a path toward 80 percent decarbonization by 2050. DOE hosted a 1-day workshop to better understand possible pathways to achieving substantial economy-wide GHG emissions reductions by 2050.

Participants from academia, DOE, the National Laboratories, and other interested stakeholder groups met to discuss two main topics: (1) potential pathways for substantial GHG reductions in electricity generation, and (2) how future end-use demand for electricity might shape the scale of required GHG emissions reductions in the electric power sector. There were two primary goals for the workshop. The first goal was to identify a set of representative pathways (and elements of such pathways) toward substantial economy-wide reductions in GHG emissions by 2050. The second goal was to identify the key characteristics, challenges, opportunities, and requirements of different pathways. The workshop informed analysis of the transition to a cleaner, low-carbon electricity system for QER 1.2.

Electricity Use in Rural and Islanded Communities
February 8–9, 2016, Washington, D.C.

The objective of this workshop was to help EPSA's public outreach efforts by focusing on communities with unique electricity challenges. The workshop explored challenges and opportunities for reducing electricity use and associated GHG emissions while improving electricity system reliability and resilience in rural and islanded communities. Although the statement of task mentioned design of microgrids for hospitals, universities, military bases, and other unified load centers, presenters covering microgrids were encouraged to describe potential applications serving isolated communities and towns in keeping with the theme of the workshop. The workshop assembled speakers from diverse locations that have rural or islanded energy issues, including Hawaii, Alaska, North Carolina, and Vermont, and they held expertise in many facets of electricity system design and operation. Speakers were encouraged to do the following: (1) identify and share best practices between rural and islanded electricity system users and operators, and (2) provide suggestions for Federal policies and research and development investments that could be implemented in both the near and long term.

The Future of Energy Efficiency
February 10, 2016 – Washington, D.C.

This session, held at a meeting of the National Association of State Energy Offices, provided a discussion of the role of energy efficiency in response to the emerging electric system challenges and opportunities that DOE intends to address in QER 1.2. The purposes of this workshop were to focus on issues related to electricity end use and to explore the potential for energy efficiency moving forward; barriers and opportunities to overcome; system benefits and the costs of increased energy efficiency deployment; and what policies or methods can be deployed to meet evolving consumer needs, and how these needs can be met while creating a more efficient system. Key themes and areas of interest from the discussion included evolving trends in electricity demand; benefits and costs for energy efficiency in a more integrated grid; options for increasing consumer value/equity/access to services; the potential for greater electrification and decarbonization of the economy; data access and security issues; the improvement of methods for valuing energy efficiency; and opportunities for new services and business models.

The Future of U.S. Bulk Power Markets

March 4, 2016 – Washington, D.C.

DOE, in coordination with Boston University's Institute for Sustainable Energy, hosted a technical workshop to gather input from current industry stakeholders on the future of the Nation's bulk power markets. The workshop also included distinct discussions on the state of transmission-planning efforts, essential reliability services (also known as ancillary services), and the potential for markets at the distribution-system level.

Participants from academia, industry associations, individual companies, public power, and state/Federal regulatory agencies were encouraged to discuss these topics and outline the major issues in their respective areas of expertise. The participants provided recommendations and feedback for ways in which DOE and the QER process could help alleviate those issues. The workshop ultimately informed the direction of subsequent analyses in support of QER 1.2, specifically with regard to transmission systems and resource adequacy constructs.

Workshop on Siting and Regulating Carbon Capture, Utilization, and Storage Infrastructure

April 8, 2016 – Washington, D.C.

DOE sponsored a workshop to identify and promote best practices for siting and regulating carbon dioxide (CO_2) infrastructure—including pipelines, enhanced oil recovery, and saline CO_2 storage sites. The purposes of this workshop were to foster communication and coordination, as well as to share lessons learned and best practices among states that are already involved in siting and regulating CO_2 infrastructure or that may have proposed future CO_2 infrastructure projects.

The workshop convened subject matter experts, industry representatives, Federal officials, and state agencies with jurisdiction over energy infrastructure planning, siting, and economic development. The aim of the workshop was to facilitate a knowledge exchange regarding CO_2 pipeline and storage-site infrastructure needs. The workshop also informed issues being addressed in QER 1.2, including discussions around CO_2-enhanced oil recovery and other storage sites, which serve as infrastructure for entities capturing CO_2.

Technical Workshop on Electricity Valuation

May 2–3, 2016 – Washington, D.C.

DOE hosted a technical workshop to understand stakeholder issues relevant to the valuation of electricity system technologies, products, and services. The workshop sought to examine four major topics: (1) valuing electricity system components and attributes, (2) valuing technologies for contributions to power quality and reliability, (3) managing electricity risks, and (4) valuation within the distribution system.

The workshop included stakeholders from state and Federal regulatory agencies, electric utilities, technology developers and manufacturers, universities, the National Laboratories, industry associations for consumers, and electricity system operators. The opening session began with a presentation on a proposed valuation methodology. During the workshop, participants provided their views on issues that must be adequately resolved to support higher penetration levels for advanced or distributed energy technologies. Participants also discussed the challenges associated with methods to value and plan for their integration. The workshop informed and improved analysis commissioned on valuation for QER 1.2.

QER 1.2 Finance Workshop

June 1, 2016 – New York, New York

As input to the QER 1.2, EPSA hosted a technical workshop to gather stakeholder views on power sector finance in the context of national energy objectives, a changing resource mix, and new technologies and business models. The discussion focused on financing required to deploy proven or advanced clean electricity technologies. Workshop participants included senior leaders from industry and investor communities, who were encouraged to provide examples of existing barriers and ideas on effective public policies and programs for U.S. electricity system modernization.

Participants emphasized that there is sufficient capital available for proven clean electricity projects with an identified revenue stream, but there is a revenue model problem for many projects and technologies. Some of the topics discussed included the potential role of grid-scale storage, challenges with large-scale nuclear, and the need for policy stability. Participants also encouraged a systems approach to modernization. They emphasized the need to provide assets with revenue streams (via price signals) for all services they provide to the grid so that asset valuations reflect their overall value to the system. The discussion included near-term, incremental changes to facilitate asset financing and deployment such as changes to the tax code, as well as longer-term policy and market changes such as incentive-based regulation, a clean capacity incentive, or pricing local reliability to provide an economic signal for customers to behave in ways that benefit the grid.

Technical Workshop on the Implications of Increasing Electric Sector Natural Gas Demand
June 7, 2016 – Washington, D.C.

This workshop explored how medium- and long-term planning is evolving given the trend of increased use of natural gas in the electric power sector. While there are favorable economic and environmental benefits to increased use of natural gas in electricity, potential challenges in infrastructure compatibility and reliability arise, as well. Stakeholders from both the natural gas and electric sectors from different regions of the country convened at this workshop. Participants then shared the practices, tools, and metrics that they employ in order to understand the interdependency between the electric and natural gas industries, as well as the approaches that stakeholders have implemented to resolve challenges and leverage opportunities.

Accelerate Energy Productivity 2030 Executive Review and Dialogue Session
June 28, 2016 – Washington, D.C.

The purpose of this session was not only to provide input to DOE from key industry representatives but also to build upon the work done under the Accelerate Energy Productivity 2030 partnership between DOE, the Alliance to Save Energy, and the Council on Competitiveness. Through the partnership, energy productivity has become an increasingly influential way to drive meaningful policy deployment in the United States and abroad. This session followed the 2014 announcement of the initiative at the 2014 American Energy and Manufacturing Competitiveness (AEMC) Summit by Secretary of Energy Ernest Moniz and the release of *Accelerate Energy Productivity 2030: A Strategic Roadmap for American Energy Innovation, Economic Growth* at the 2015 AEMC. Representatives at the session provided input on several issues relevant to the QER 1.2, including increased deployment of electric vehicles; electric utility rate design that supports deployment of new technologies; regulatory consistency and certainty; improvement of electric consumer equity; ensuring a strong electric sector workforce; the role of states in driving energy productivity; the role of incentives and consumer awareness in promoting clean energy technology; the importance of public-private partnerships; and improved access to financing for energy efficiency.

QER Stakeholder Engagement

In the Presidential Memorandum establishing the QER, President Obama directed the QER Task Force to "gather ideas and advice from state and local governments, tribes, large and small businesses, universities, National Laboratories, nongovernmental and labor organizations, consumers, and other stakeholders and interested parties." The President also ordered the QER Task Force to "develop an integrated outreach strategy that relies on both traditional meetings and the use of information technology."

In its role as Secretariat for the QER Task Force, EPSA undertook an open, transparent process for informing stakeholders of the purposes and scope of the QER 1.2.

This outreach process included the following:

- Informal meetings at DOE headquarters involving EPSA staff members and dozens of stakeholder groups from the electricity sector, such as academic researchers; local, state, and Federal governments; and regulatory agencies
- Briefings on the QER process at meetings with industry associations; groups of state officials; the offices of environmental groups; and with Members of Congress, their staffs, and the staffs of multiple relevant congressional committees
- A series of seven formal public stakeholder meetings, beginning in Washington, D.C., and extending to Boston, Massachusetts; Salt Lake City, Utah; Des Moines, Iowa; Austin, Texas; Los Angeles, California; and Atlanta, Georgia
- Special dialogues with officials in Canada and Mexico to discuss cross-border integration and international collaboration, given the extensive electricity integration that exists between the United States and Canada and opportunities present to increase integration between the United States and Mexico
- Speeches and briefings to interested groups in Washington, D.C., and across the country by the Secretary of Energy, the Director of the President's Office of Science and Technology Policy, other White House officials, and various members of DOE leadership
- The creation of a public comments portal to allow interested stakeholders and the general public to provide comments on individual stakeholder meetings, as well as outside experts to submit studies, reports, and data sets related to topics within the scope of the QER 1.2.

Formal Public Stakeholder Meetings

The most visible effort to engage stakeholders during the QER 1.2 process was the series of seven public meetings held around the country from February to May 2016. These meetings provided opportunities for the Administration to fully consider the unique challenges and opportunities facing each of the many geographically diverse segments of our Nation's electricity system. The regions selected for QER 1.2 stakeholder meetings were based on wholesale market footprints as a convenient approach to capturing the Nation's regional electricity diversity, which is also characterized by differing resource mixes, state policies, and a host of other factors.

The mixture of panel discussions and a public comment period framed multi-stakeholder discourse around deliberative analytical questions in QER 1.2 relating to the intersection of electricity and its role in promoting economic competitiveness, energy security, and environmental responsibility. The Administration sought public input on key questions relating to possible Federal actions that would address the challenges and take full advantage of the opportunities of this changing system to meet the Nation's objectives of reliable, affordable, and clean electricity.

Each meeting began with opening statements by the hosting Administration representatives, along with local, state, and national political leaders who participated at events in their parts of the country. Each meeting, with the exception of the kickoff meeting in Washington, D.C., had three panel discussions. The first two topics were the same for all regions (*Bulk Power Generation and Transmission Opportunities: How Can We Plan, Build, and Operate the Appropriate Amount for Future Needs?* and *Electricity Distribution and End-Use: How Do We Manage Challenges and Opportunities?*)—although content varied as there are significant regional differences. The third panel's topics were different for each session to highlight issues of regional importance. Each meeting concluded with an "open microphone" segment, during which members of the general public could make statements for the QER 1.2 record and had the opportunity to offer prepared presentations, studies, reports, and more for review by EPSA analysts and inclusion in the QER Library.

Federal Register notices announcing each formal public stakeholder meeting were published; these notices also were made available via the DOE QER website (http://energy.gov/epsa/quadrennial-energy-review-qer). DOE publicized the meetings by sending advisories to local media; using social media; and emailing state, local, and tribal governments, as well as representatives of energy stakeholders—both in the region of each meeting and in Washington, D.C.

In the interests of transparency and open government, court reporters produced a transcript for each meeting, and EPSA produced a summary of each meeting's presentations and discussions. The transcripts and summaries, along with links to the live-streamed recordings and panelists' prepared remarks and presentations, are available on the DOE QER website.

Following are details about the dates, topics, locations, and focus areas of the formal public stakeholder meetings organized by EPSA to inform QER 1.2 (Table 8-2).

Table 8-2. List of QER 1.2 Formal Public Stakeholder Meetings (with Topic, Location, Date, and Administration Officials)[d]

Location	Topic (Third Panel)	Date	Administration Chair(s) and Local/State/Congressional Officials
Washington, D.C.	Electricity: generation to end use	2/4/16	Secretary of Energy Ernest Moniz, Assistant to the President for Science and Technology Dr. John Holdren, Deputy Assistant to the President for Energy and Climate Change Dan Utech, and Representative Earl Blumenauer (D-OR)
Boston, MA	Resource adequacy	4/15/16	Secretary of Energy Ernest Moniz, Assistant to the President for Science and Technology Dr. John Holdren, and Governor Charlie Baker
Salt Lake City, UT	Cyber and physical security and resilience	4/25/16	Deputy Assistant to the President for Energy and Climate Change Dan Utech and Deputy Administrator of the USDA Rural Utilities Service Joshua Cohen
Des Moines, IA	Transmission development	5/6/16	Secretary of Energy Ernest Moniz, Governor Terry Branstad, Lieutenant Governor Kim Reynolds, Mayor T.M. Franklin Cownie, and USDA Rural Development Rural Business-Cooperative Service Administrator Sam Rikkers
Austin, TX	New technologies and actors in the grid edge space	5/9/16	Secretary of Energy Ernest Moniz, USDA Deputy Under Secretary for Rural Development Lillian Salerno, and Mayor Steve Adler (Austin)
Los Angeles, CA	Generating and delivering electricity to meet GHG targets	5/10/16	Deputy Secretary of Energy Elizabeth Sherwood-Randall, USDA Rural Development Rural Business-Cooperative Service Administrator Sam Rikkers, and Deputy Mayor for City Services Barbara Romero (Los Angeles)
Atlanta, GA	Financing new electricity infrastructure	5/24/16	Secretary of Energy Ernest Moniz and Deputy Administrator of the USDA Rural Utilities Service Joshua Cohen

Dates, topics, locations, and focus areas for the formal QER 1.2 Stakeholder Meetings.

[d] Acronyms used in Table 8-2 include the following: GHG–greenhouse gas; USDA–U.S. Department of Agriculture.

1. **Washington, D.C., Kickoff Meeting**

   February 4, 2016

   The Washington, D.C., public stakeholder meeting served as the formal kickoff meeting for QER 1.2, an integrated study of the U.S. electricity system from generation through end use. The meeting included two main panel discussions and a public comment period focused on the challenges and opportunities facing the electricity sector and its key role in promoting economic competitiveness, energy security, and environmental responsibility.

2. **Boston, Massachusetts**

   April 15, 2016

   The QER 1.2 public stakeholder meeting in Boston covered the footprint of the 21 states and District of Columbia that are, all or in part, in the regional transmission organization (RTO) PJM Interconnection, Independent System Operator (ISO) New England, or New York ISO. The third panel for the Boston public stakeholder meeting covered "Ensuring Resource Adequacy," highlighting the proper design and operation of the eastern RTO/ISO markets—with Federal and state policies and consumer demand creating momentum for low-carbon options—as crucial.

3. **Salt Lake City, Utah**

   April 25, 2016

   The Salt Lake City meeting covered the footprint of 13 of the 14 states (excluding California) that are, all or in part, in the Western Interconnection, and that are represented by the Western Electricity Coordinating Council. The third panel in the Salt Lake City public stakeholder meeting covered "Cyber/Physical Security and Resilience."

4. **Des Moines, Iowa**

   May 6, 2016

   The Des Moines meeting covered the footprint of the 20 states that are, all or in part, in the Southwest Power Pool and the Midcontinent ISO. The third panel in the Des Moines public stakeholder meeting covered "Transmission Development with an Evolving Generation Mix."

5. **Austin, Texas**

   May 9, 2016

   The Austin meeting covered the footprint of the State of Texas, grid operations, and the flow of energy—most of which is managed by the Electric Reliability Council of Texas. The third panel in the Austin public stakeholder meeting covered "New Technologies and Actors in the Grid Edge Space."

6. **Los Angeles, California**

   May 10, 2016

   The Los Angeles meeting covered the footprint of the State of California, grid operations, and the flow of energy—most of which is managed by the California ISO. The third panel for the Los Angeles public stakeholder meeting covered "Generating and Delivering Electricity in a High GHG-Reduction Environment."

7. **Atlanta, Georgia**

   May 24, 2016

   The Atlanta meeting covered the footprint of the 10 southeastern states that, all or in part, have bilateral wholesale electricity markets. The third panel for the Atlanta public stakeholder meeting covered "Financing New Electricity Infrastructure."

Comments Portal and QER Library

From the beginning of the QER 1.2 process, stakeholders and the general public were encouraged to offer suggestions, comments, insights, and criticisms on issues surrounding the electricity system. Public comments were collected through a web-based portal, which allowed stakeholders to share comments as well as studies, reports, data sets, and any additional materials from stakeholder organizations to help inform QER 1.2. All comments submitted to the portal are publicly available at https://energy.gov/epsa/comments-second-installment-quadrennial-energy-review.

EPSA received 295 total comments—including 215 total attachments comprising detailed reports and studies on behalf of trade associations, utilities, and energy companies; state and local governments; nonprofit organizations; and other stakeholders (totaling over 2,600 pages). EPSA reviewed each of the comments received. Insights and recommendations extracted from these comments and materials were grouped into multiple themes, namely issues with evolving generation mix; increased attention to cybersecurity and physical security; reliability needs during transformation; problems with organized wholesale markets; evolving transmission planning and investment; activity at distribution and end-use sector; valuation and rate reform; business models; evolving state and Federal regulations; and the Federal role.

QER Interagency Engagement

As outlined by the QER Presidential Memorandum, the President identified more than 20 executive departments and agencies that play key roles in developing and implementing policies governing energy resources and consumption, as well as associated environmental impacts. The President directed the QER Secretariat (1) to develop a comprehensive and integrated review of energy policy, based on interagency dialogue and active engagement of external stakeholders, and (2) to make recommendations on what additional actions it believes would be appropriate. The findings and recommendations in QER 1.2 are based on Task Force deliberations, meetings with staff-level agency representatives and experts, and information provided to the Secretariat and the Task Force by external stakeholders.

Throughout the development of QER 1.2, the White House convened regular interagency meetings and worked closely with the agencies' leadership and staff. Member agencies collaborated to develop QER 1.2 by providing information on topics within their statutory and regulatory jurisdiction or areas of particular expertise related to energy infrastructure transmission, storage, and distribution. Agencies delivered studies, data, and other information to be considered in policy analysis and modeling; reviewed analysis and findings; and leveraged the work of other relevant Administration initiatives. Led by the Office of Science and Technology Policy and the Domestic Policy Council, they collaboratively developed policy recommendations. A series of roundtable discussions was held with representatives from key departments and agencies to ensure a transparent and inclusive process in the development of policy recommendations.

Interagency members also partnered with the Secretariat on the seven formal public stakeholder meetings, opening the events and setting the focus for the expert panels that followed.

Appendix

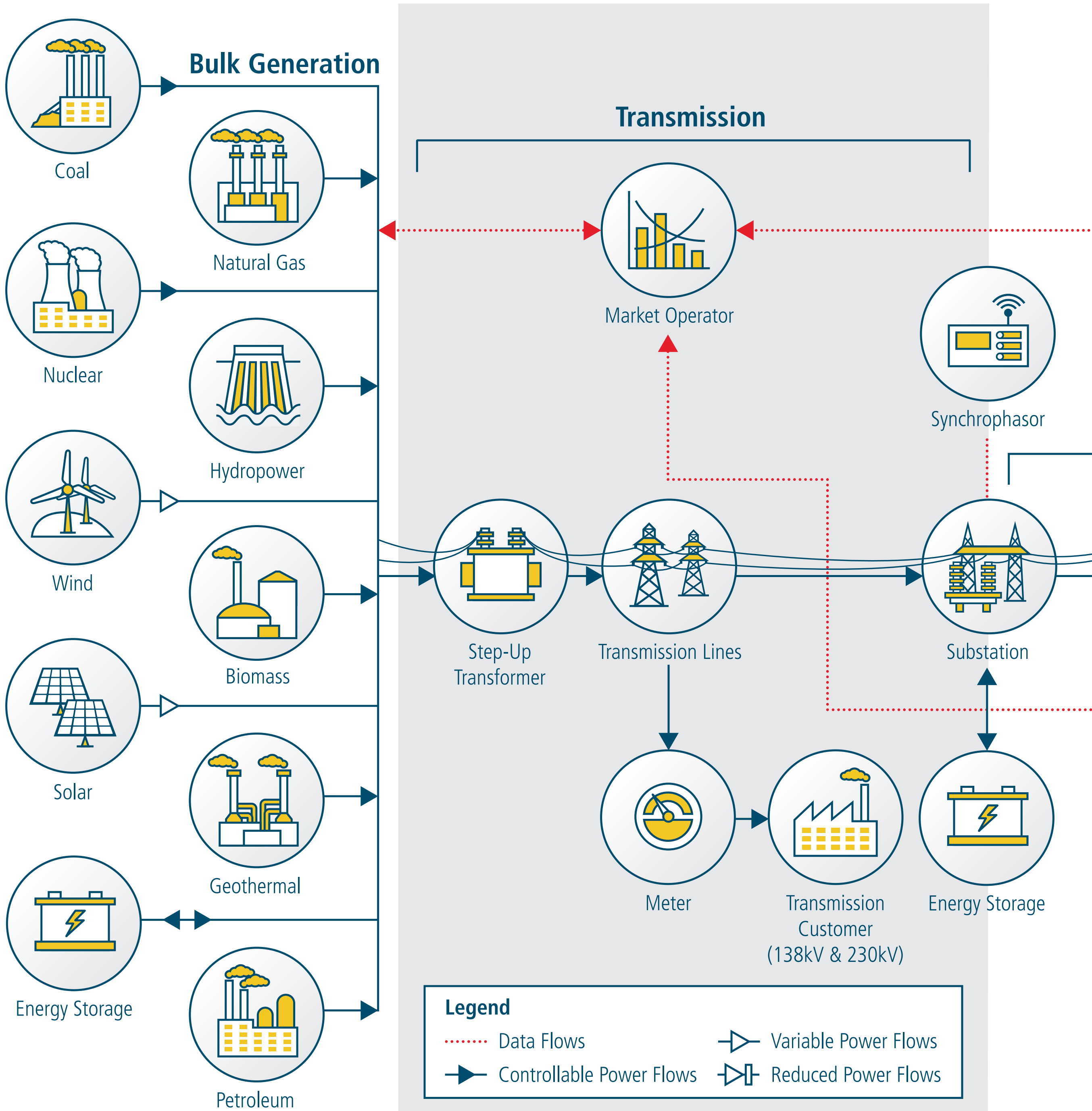
ELECTRICITY SYSTEM OVERVIEW

This appendix provides context for understanding the analysis and recommendations contained in the main body of the report. It is an overview of the Nation's existing electricity system, including its physical structure and elements, the history of its development, and major laws and jurisdictions governing its operation. It explores the Federal role in the resilience and security of the electric grid, and it describes the complex operations, business models, and market structures comprising the electricity system.

Elements of the Electricity System

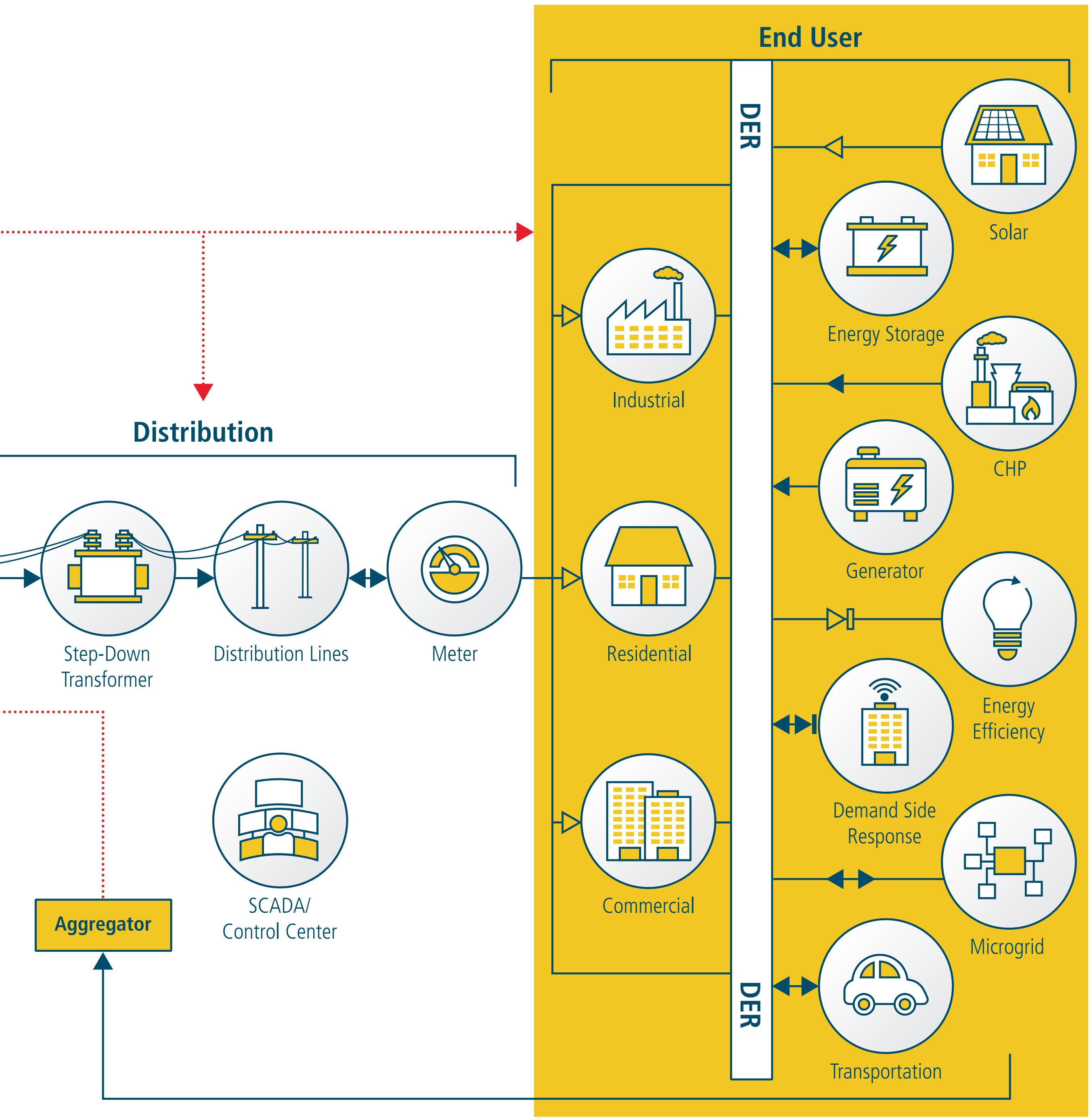
The U.S. electric power system is an immensely complex system-of-systems, comprising generation, transmission, and distribution subsystems and myriad institutions involved in its planning, operation, and oversight (Figure A-1). End use and distributed energy resources (DER) are also important parts of the electric power system.

Figure A-1. Schematic Representation of the U.S. Electric Power System



The electric power system comprises the following broad sets of systems: bulk generation, transmission, distribution, and end use (including DER).

Acronyms: combined heat and power (CHP), distributed energy resources (DER), kilovolts (kV), supervisory control and data acquisition (SCADA).


End User
DER
Solar
Energy Storage
Industrial
CHP
Distribution
Generator
Residential
Step-Down
Transformer
Distribution Lines
Meter
Energy
Efficiency
Demand Side
Response
SCADA/
Control Center
Commercial
Microgrid
Aggregator
DER
Transportation

Generation

Electricity generation accounts for the largest portion of U.S. primary energy use, using 80 percent of the Nation's domestically produced coal,[1] one-third of its natural gas, and nearly all of its nuclear and non-biomass renewable resource production. In 2014, 39 percent of the Nation's primary energy use was devoted to electricity generation, and electricity accounted for 18 percent of U.S. delivered energy.[2]

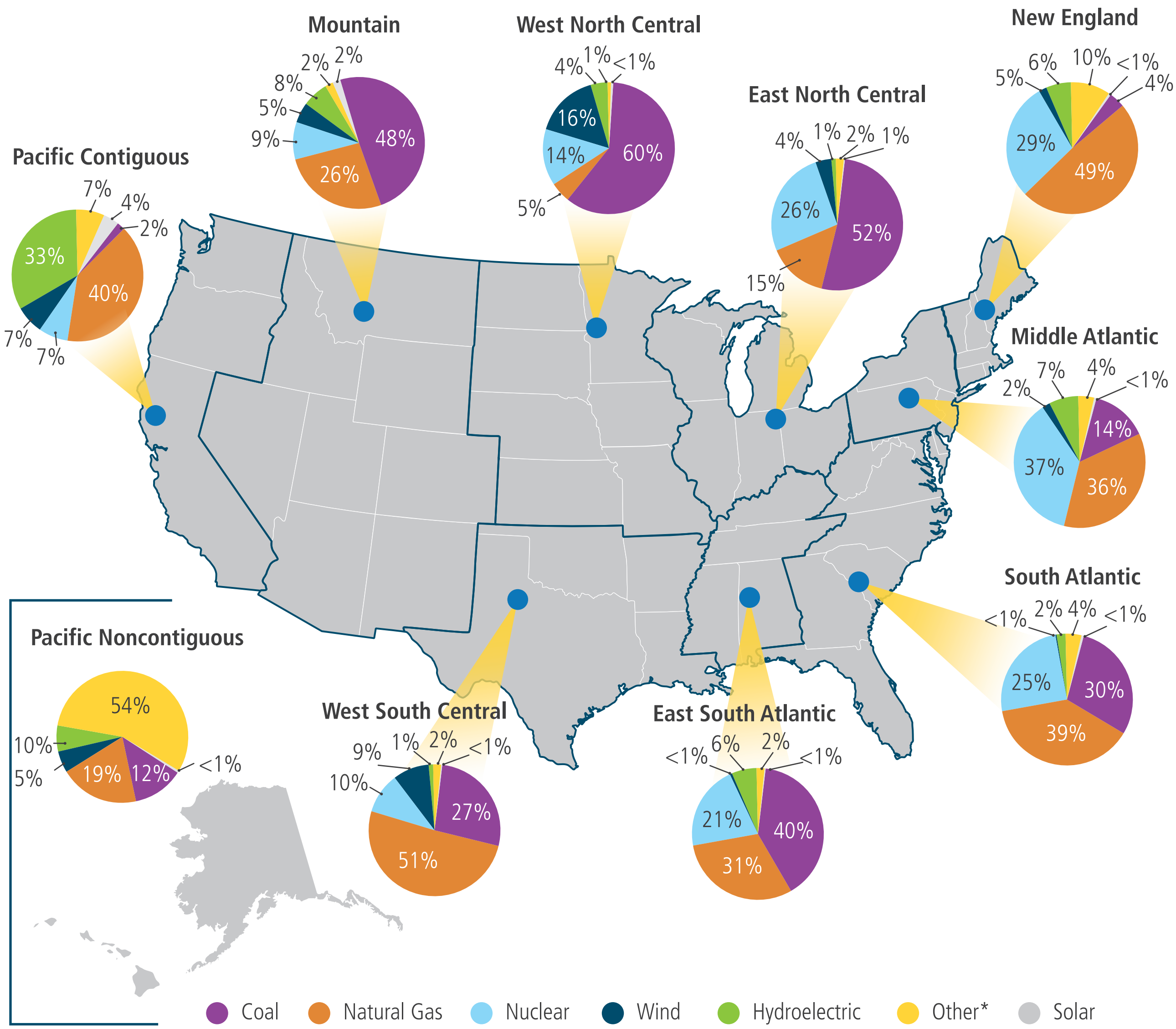
In 2014, there were over 6,500 operational power plants of at least 1 megawatt in the U.S. electric power system.[a, 3, 4] These power plants delivered nearly 3,764 billion kilowatt-hours (kWh) of power in 2014, supplying electricity to over 147 million residential, commercial, and industrial customers at an average price of $0.104/kWh for a total revenue from electricity sales of more than $393 billion.[5, 6, 7, 8]

The U.S. electricity generation portfolio is diverse and changes over time through the commercial market growth of specific generation technologies—often due to a confluence of policies, historic events, fuel cost, and technology advancement. Today, coal and natural gas each provide roughly one-third of total U.S. generation; nuclear provides 20 percent; hydroelectric and wind provide roughly 5 percent each; and other resources, including solar and biomass, contribute less than 2 percent each.[9] However, there are major generation mix differences between regions (Figure A-2).[10]

The availability of primary energy resources, like coal and natural gas, and renewable energy resources, like wind and solar, differs widely across the country (Figure A-3). This dispersed resource availability influences the regional generation mixes.

[a] A megawatt is a thousand kilowatts. A kilowatt is a unit of power output commonly used in the electricity industry. A kilowatt-hour (kWh) is a related unit of energy (the amount of power provided times the number of hours that it is provided). Electricity is usually billed by the kWh. An average American home uses roughly 11,000 kWh per year. Source: "How Much Electricity Does an American Home Use?" Energy Information Administration, Frequently Asked Questions, last modified October 18, 2016, https://www.eia.gov/tools/faqs/faq.cfm?id=97&t=3.

Figure A-2. Electric Power Regional Fuel Mixes, 2015[11, 12]



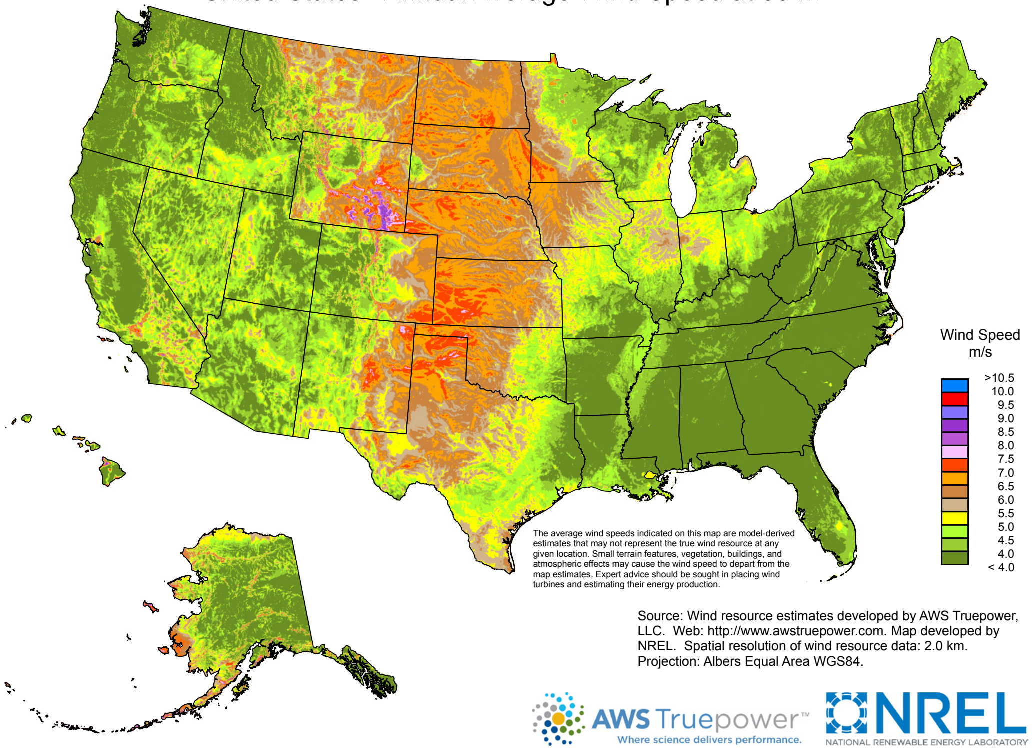
*Includes the following Energy Information Administration fuel type designations: Distillate Petroleum, Geothermal, Biogenic Municipal Solid Waste and Landfill Gas, Other Gases, Other Renewables, Other (including nonbiogenic municipal solid waste), Petroleum Coke, Residual Petroleum, Waste Coal, Waste Oil, and Wood and Wood Waste.

Note: Sum of components may not add to 100% due to independent rounding.

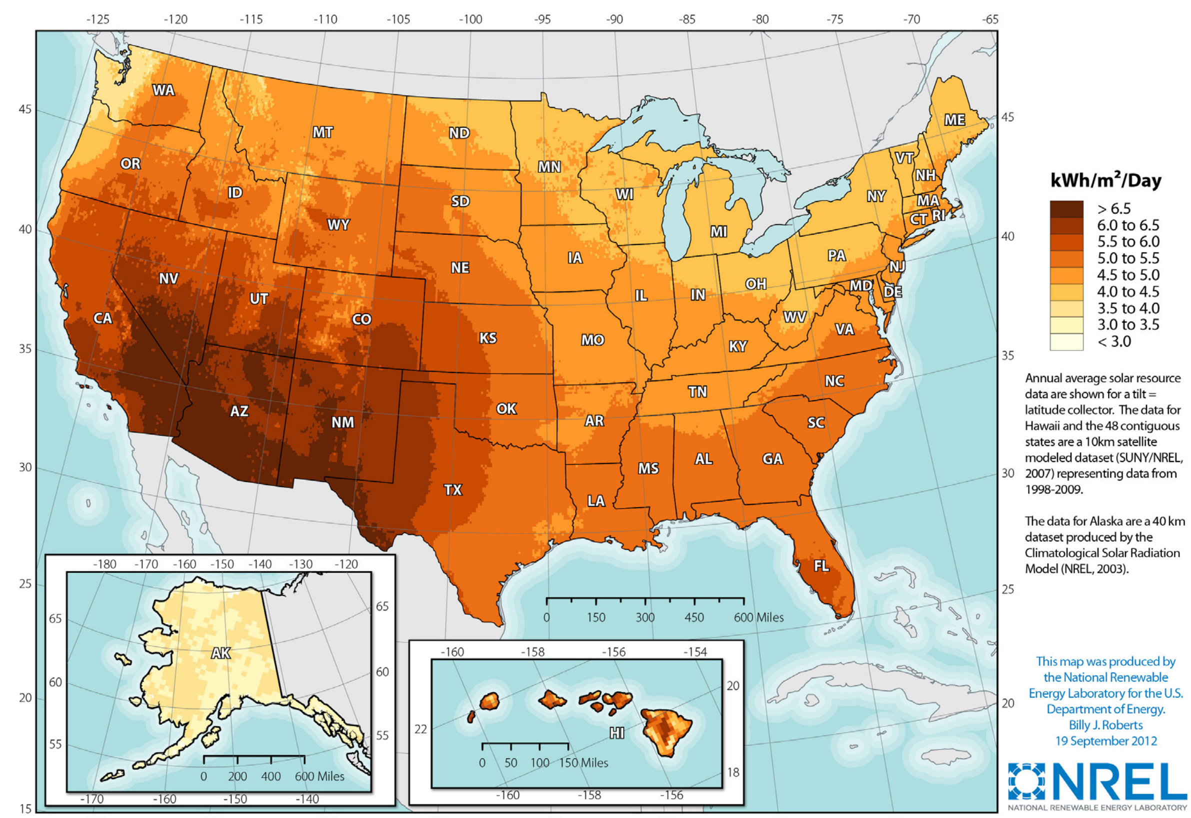
The U.S. electricity industry relies on a diverse set of generation resources with strong regional variations. As of 2015, coal fuels the majority of electricity generation in the Mountain, West North Central, East North Central, and East South Central regions. Coal is also a significant resource for the South Atlantic and West South Central regions, though both have sizable natural gas generation as well, and the South Atlantic region includes substantial shares of nuclear. The Pacific Contiguous and New England regions are predominately natural gas, with significant contributions of hydroelectric and nuclear, respectively. The Middle Atlantic is the only region that is predominately nuclear, and the Pacific Noncontiguous region is the only region in which fuel oil represents more than a few percentage points of total generation, where it constitutes nearly half of all generation.

Figure A-3. Wind and Solar Energy Resource Maps for the United States[13,14]

United States - Annual Average Wind Speed at 30 m



Photovoltaic Solar Resource of the United States



Energy resource availability varies widely across the United States. Wind and solar energy resources are concentrated in the Midwest and Southwest regions of the United States.

Transmission

The U.S. transmission network includes the power lines that link electric power generators to each other and to local electric companies. The transmission network in the 48 contiguous states is composed of approximately 697,000 circuit-miles[b] of power lines and 21,500 substations operating at voltages of 100 kilovolts (kV)[c] and above.[15] Of this, 240,000 circuit-miles are considered high voltage, operating at or above 230 kV (Figure A-4).[16] A substation is a critical node within the electric power system and is composed of transformers, circuit breakers, and other control equipment. Distribution substations are located at the intersection of the bulk electric system and local distribution systems.

The vast majority of transmission lines operate with alternating current (AC). With commonly used technology, system operators cannot specifically control the flow of electricity over the AC grid; electricity flows from generation to demand through many paths simultaneously, following the path of least electrical resistance. A limited number of transmission lines are operated using direct current (DC). Unlike AC transmission lines, the power flows on DC lines are controllable. However, their physical characteristics make them cost-effective only for special purposes, such as moving large amounts of power over very long distances.[17]

Electricity moved through transmission and distribution systems faces electrical resistance and other conversion losses. Losses from resistance and conversion amount to 5 to 6 percent of the total electricity that enters the system at the power plant.[18]

Each transmission line has a physical limit to the amount of power that can be moved at any time, which depends on the conditions of the power system. Within one market or utility control area, physical limits of system assets are the primary drivers of power price differences in different parts of the system.

Distribution System

The role of the large generators and transmission lines that comprise the bulk electric system is to reliably provide sufficient power to distribution substations. In turn, the distribution system is responsible for delivering power when and where customers need it while meeting minimum standards for reliability and power quality.[19] Power quality refers to the absence of perturbations in the voltage and flow of electricity that could damage end-use equipment or reduce the quality of end-use services.[20]

Before delivery to a customer, electric power travels over the high-voltage transmission network (at hundreds of kilovolts) to a distribution substation where a transformer reduces the voltage before the electricity moves along the distribution system (at tens of kilovolts). Several primary distribution feeder circuits, connected by an array of switches at the distribution bus, emanate from the substation and pass through one or more additional transformers before reaching the secondary circuit that ultimately serves the customer. One or more additional transformers reduce the voltage further to an appropriate level before arriving at the end-use customer's meter.[d, 21]

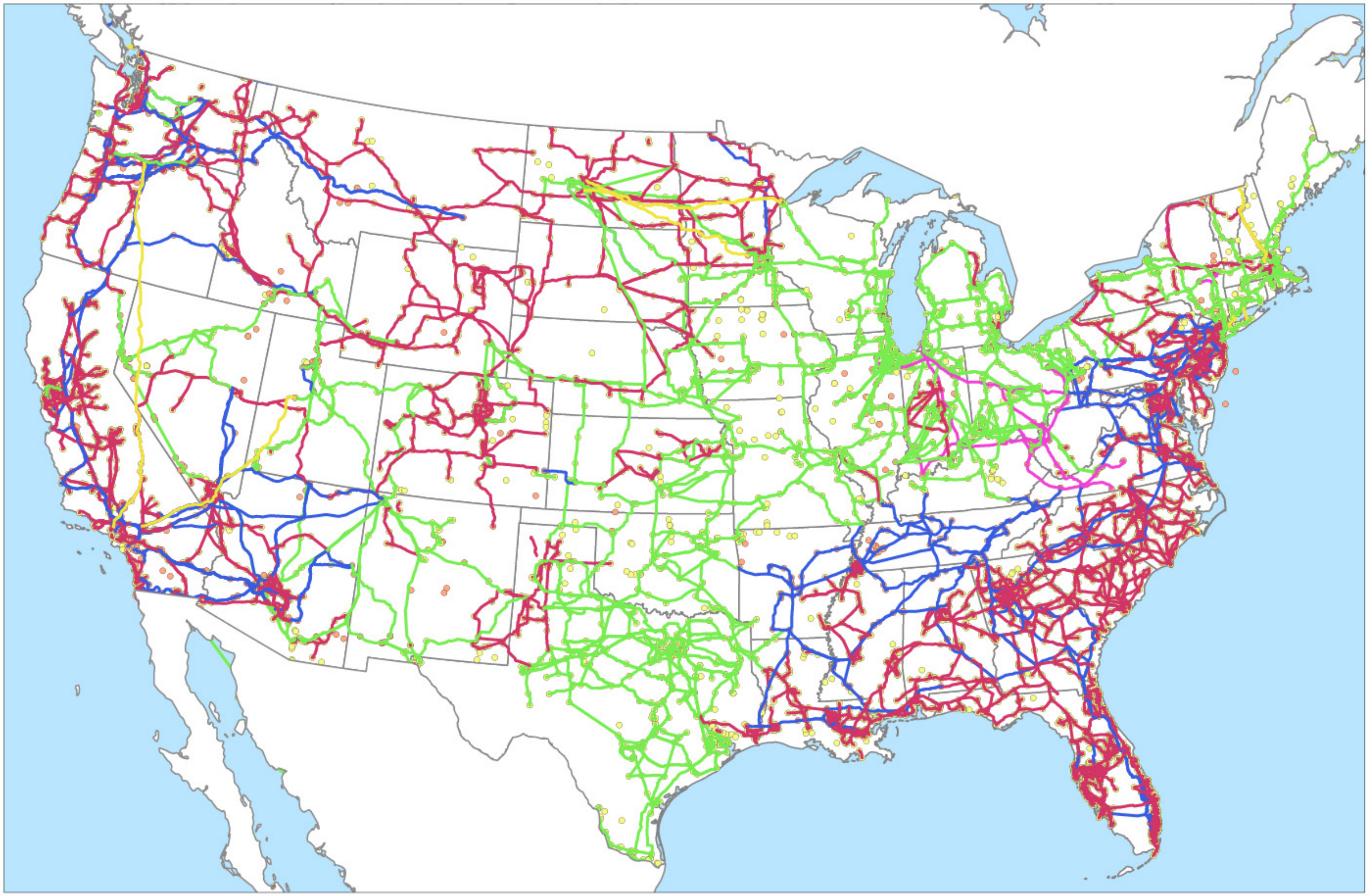
An emerging role of the distribution system is to host a wide array of distributed energy generation, storage, and demand-management technologies. Though some distributed energy technologies—like campus-sized combined heat and power—have existed for decades, rapid cost declines in solar, energy storage, and power electronic technologies, coupled with supportive policies, have led to a rapid proliferation of new devices and, at times, new challenges and opportunities for the planning and operation of distribution systems.

[b] A circuit-mile is 1 mile of one circuit of transmission line. Two individual 20-mile lines would be equivalent to 40 circuit-miles. One 20-mile double-circuit section would also be equivalent to 40 circuit-miles.

[c] A kilovolt (kV) is a commonly used unit of electrical "force" in the electricity industry. Electricity at higher voltages moves with less loss; however, system components able to manage high voltage are costly, and high voltages can be dangerous. Lower voltage is used in distribution systems to manage costs on system equipment and for safety.

[d] Most residential and commercial customers in the United States receive two 120-volt (V) connections. Most household plugs provide 120 V, while large appliances like dryers and ovens often combine the two 120-V connections into a single 240-V supply.

Figure A-4. High-Voltage Transmission Network and Substations of the 48 Contiguous States, 2015[22]



The transmission network comprises approximately 697,000 circuit-miles—of which roughly 240,000 miles operate at or above 230 kV—and 21,500 substations operating at voltages of 100 kV and above.[23, 24, 25]

Distributed Energy Resources (DER)

DER constitute a broad range of technologies that can significantly impact how much, and when, electricity is demanded from the grid. Though definitions of DER vary widely, the term is used in the Quadrennial Energy Review (QER) to refer to technologies such as distributed generation (DG), distributed storage, and demand-side management resources, including energy efficiency. Given the multiple definitions and understandings of the term DER, the QER will use DER to refer to the full range of these technologies and will delineate specific technologies where only some are relevant. Current and projected market penetration of DG is shown in Table A-1.

DER technologies can be located on a utility's distribution system or at the premises of an end-use customer. They differ with respect to several attributes, though a key differentiator is their level of controllability from a grid management perspective. Certain DER, such as energy efficiency or rooftop solar photovoltaic, impact total load but may not be directly controlled by grid operators. Other DER, such as DR or controllable distributed energy storage, can be more directly managed and called upon by grid operators when needed.

Table A-1. Current and Projected Distributed Generation Market Penetration, 2015 and 2040[26]

Resource	Total Generation (GWh)		% of Total Utility Generation	
	2015	2040	2015	2040
Combined Heat and Power (CHP)	166,946	246,896	4.2%	5.2%
Rooftop Solar PV	13,453	64,485	0.3%	1.4%
Distributed Wind	637	1,643	0.0%	0.0%
Other DG	4,298	4,298	0.1%	0.1%
Total Distributed Generation	185,334	317,323	4.7%	6.7%
Total Utility-Scale Generation	**3,947,520**	**4,745,441**		

Other DG includes small-scale hydropower; biomass combustion or co-firing in combustion systems; solid waste incineration or waste-to-energy; and fuel cells fired by natural gas, biogas, or biomass. Backup generators (for emergency power) are not included here because generation data are limited, and these generators are not used in normal grid operation.

Acronyms: distributed generation (DG); gigawatt-hours (GWh); photovoltaic (PV).

End Use

Electricity end-use infrastructure includes physical components that use, require, or convert electricity to provide products or services to consumers. Since the first time the electric light bulb lit up New York City, nearly all parts of the United States have gained access to electricity.[e] In that time, the proliferation of novel and unanticipated uses of electricity has placed electricity at the center of everyday life and established it as the engine for the modern economy.

Today, the residential and commercial sectors each consume about the same share of total electricity—38 percent and 36 percent, respectively—with the industrial sector accounting for an additional 26 percent of electricity demand.[27, 28] Cumulatively, electricity sales to end-use customers in the United States generated approximately $393 billion in 2014.[29, 30] Moving forward, new technologies, from automated thermostats to electric vehicles, are changing the way consumers use electricity.

[e] There are thousands of households in Indian lands that still do not have access to electricity.

Electricity is a high-quality energy source available at a relatively low price. However, many low-income Americans struggle to afford their monthly electricity bills.[31] Nationally, average monthly residential bills in 2015 were $114.[32]

Brief History of the U.S. Electricity Industry

The U.S. electricity system represents one of the greatest technological achievements in the modern era. The complexity of the modern electricity industry is the result of a complicated history.

The Beginning of the Electricity Industry

The U.S. electricity industry began in 1882 when Thomas Edison developed the first electricity distribution system. Edison designed Pearl Street Station to produce and distribute electricity to multiple customers in the New York Financial District and to sell lighting services provided by his newly invented light bulbs.[33]

Early utilities distributed power over low-voltage DC lines. These lines could not move electricity far from where it was produced, which limited utility service to areas only about a mile from the generator. Multiple generators and dedicated distribution lines were required to serve a larger area. The limited reach of distribution lines and the lack of regulation of utilities resulted in the co-location of multiple independent utilities and competition for customers where multiple distribution lines overlapped.[34, 35]

In 1896, AC generation emerged as a competitor to DC when Westinghouse Electric developed a hydropower generation station at Niagara Falls, New York, and transmitted power 20 miles to Buffalo, New York.[36] At the voltage levels used at that time, AC has better electrical characteristics for moving power over long distances. This technological development—and related business models—allowed a single utility to broaden the geographic extent of its customers and sources of revenue. A wave of consolidation followed, where small, isolated DC systems were converted to AC and interconnected with larger systems. Interconnecting with other systems and serving more customers allowed operators to take advantage of the diversity of customer demand, deliver better economies of scale, and provide lower prices than competitors.[37]

A move toward today's system of regulatory oversight occurred around the turn of the century. With the industry consolidation of the late 1890s came public concern over lack of competition and the potential for large utilities to exert a monopoly power over prices.[38] In 1898, a prominent electricity industry leader and Thomas Edison's former chief financial strategist, Samuel Insull, called for utility regulation that granted exclusive franchises in exchange for regulated rates and profits in order to create a stable financial environment that would foster increased investments and electricity access.[39] Insull claimed that such regulation was needed because utilities are natural monopolies, meaning that a single firm can deliver a service at a lower total cost than multiple firms through economies of scale and avoidance of wasteful duplication (e.g., multiple distribution substations and circuits belonging to different companies serving a single area).

In 1907, Wisconsin became the first state to regulate electric utilities, and by 1914, 43 states had followed.[40, 41] The general form of utility regulation that was established by the Wisconsin legislature in 1907 endures today and is called the "state regulatory compact."

This compact allowed electric utilities to operate as distribution monopolies with the sole right to provide retail service to all customers within a given franchise area—as well as an obligation to do so. Those monopolies were allowed an opportunity to earn a fair rate of return on their investments. Some municipal governments across the country created their own utilities, owned and governed by the local government, as an alternative to investor-owned, regulated utilities.[42, f]

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[f] Other types of publicly owned electric utilities, besides those owned by municipal governments, include utilities organized around states, public utility districts, and irrigation districts. The term "public power" is often used to refer to electricity utilities operated by any of these political subdivisions.

The State Regulatory Compact

The "state regulatory compact" evolved as a concept "to characterize the set of mutual rights, obligations, and benefits that exist between the utility and society."[g] It is not a binding agreement. Under this "compact," a utility typically is given exclusive access to a designated—or franchised—service territory and is allowed to recover its prudent costs (as determined by the regulator) plus a reasonable rate of return on its investments. In return, the utility must fulfill its service obligation of providing universal access within its territory. The "regulatory compact" applies to for-profit, monopoly investor-owned utilities that are regulated by the government. The compact is less relevant to public power and cooperative utilities, which are nonprofit entities governed by a locally elected or appointed governing body and are assumed to inherently have their customers' best interests in mind. Regulators strive to set rates such that the utility has the opportunity to be fully compensated for fulfilling its service obligation. While not technically part of the "compact," customers also have a role to play in this arrangement: they give up their freedom of choice over service providers and agree to pay a rate that, at times, may be higher than the market rate in exchange for government protection from monopoly pricing. In effect, utilities have the opportunity to recover their costs, and, if successful, their investors are provided a level of earnings; customers are provided non-discriminatory, affordable service; and the regulator ensures that rates are adequately set such that the aforementioned benefits materialize.

[g] Karl McDermott, *Cost-of-Service Regulation in the Investor-Owned Electric Utility Industry: A History of Adaptation* (Washington, DC: Edison Electric Institute, 2012), http://www.eei.org/issuesandpolicy/stateregulation/Documents/COSR_history_final.pdf.

In the early 1900s, states regulated nearly all of the activities of electric utilities—generation, transmission, and distribution.[43] However, a 1927 Supreme Court case[44] held that state regulation of wholesale power sales by a utility in one state to a utility in a neighboring state was precluded by the commerce clause of the U.S. Constitution.[45] These transactions were left unregulated as Congress had the authority to regulate, but no Federal agency existed to do so.[46]

The 1935 Federal Power Act (FPA) addressed the regulatory gap by providing the Federal Power Commission (FPC, eventually renamed the Federal Energy Regulatory Commission, or FERC)[h] with authority to regulate "the transmission of electric energy in interstate commerce" and "the sale of electric energy at wholesale in interstate commerce."[47, 48] The FPA left regulation of generation, distribution, and intrastate commerce to states and localities.[49] Federal regulation was to extend "only to those matters which are not subject to regulation by the States."[50] FERC was given jurisdiction over all facilities used for the transmission or wholesale trade of electricity in interstate commerce and was charged with ensuring that corresponding rates are "just and reasonable, and not unduly discriminatory or preferential."[51, 52]

Federal Investments in Rural Electrification

Urban areas were the first areas to attract utility investment. The higher density of potential customers in urban areas made these areas more cost-effective to serve. By the 1930s, most urban areas were electrified, while sparsely populated rural areas generally lagged far behind. The Great Depression and widespread floods and drought in the Great Plains during the 1930s led to a wave of significant Federal initiatives to develop the power potential of the Nation's water resources.

[h] The Federal Power Commission was created in 1920 by the Federal Water Power Act to encourage the development of hydroelectric generation facilities.

One example of Federal efforts to capture the benefits of the Nation's water resources is the Tennessee Valley Authority (TVA). TVA was created in 1933 as a federally owned corporation to provide economic development through provision of electricity, flood control, and other programs to the rural Tennessee Valley area. To this day, TVA maintains a portfolio of generation and transmission assets to sell wholesale electricity to public power and cooperatives within its territory. Federal law grants first preference for this electricity to public power and cooperative utilities.

Congress passed the Rural Electrification Act in 1936, which encouraged electrification of areas unserved by investor-owned utilities (IOUs) and public power utilities. The act authorized rural electric cooperatives to receive Federal financing support and preferential sales from federally owned generation. The Bonneville Power Administration was created in 1937 to deliver and sell electric power from federally owned dams in the Pacific Northwest.[53] Increased Federal investment in hydropower followed through the 1940s, and by the 1960s, rural electrification was largely complete.[54]

Federally Owned Utilities

There are five Federal electric utilities: Tennessee Valley Authority (TVA), Bonneville Power Administration (BPA), Southeastern Power Administration (SEPA), Southwestern Power Administration (SWPA), and Western Area Power Administration (WAPA). TVA is an independent government corporation, while BPA, SEPA, SWPA, and WAPA are separate and distinct entities within the Department of Energy. Starting with BPA in 1937, followed by SEPA, SWPA, and WAPA, Congress established the Power Marketing Administrations (PMAs) to distribute and sell electricity from a network of more than 130 federally built hydroelectric dams.

The PMAs don't own or manage the power they sell but, in many cases, maintain the transmission infrastructure to distribute the low-cost electricity to public power and rural cooperative utilities, in addition to some direct sales to large industrial customers. The electricity-generating facilities are primarily owned and operated by the Department of the Interior's Bureau of Reclamation, the Army Corps of Engineers, and the International Boundary and Water Commission.

BPA, WAPA, and SWPA collectively own and operate 33,700 miles of transmission lines, which are integrally linked with the transmission and distribution systems of utilities in 20 states. Millions of consumers get electricity from the PMAs (usually indirectly, via their local utility), but a much larger number of consumers benefit from—and have a stake in—the continued efficient, effective operation of the PMAs and the transmission infrastructure they are building and maintaining.

TVA is a corporate agency of the United States that provides electricity for business customers and local power distributors, serving 9 million people in parts of seven southeastern states. TVA receives no taxpayer funding, deriving virtually all of its revenues from sales of electricity. In addition to operating and investing its revenues in its electric system, TVA provides flood control, navigation, and land management for the Tennessee River system and assists local power companies and state and local governments with economic development and job creation.

Electricity Industry Restructuring and Markets

As early as the 1920s, utilities sought operational efficiencies by coordinating generation dispatch and transmission planning across multiple utility territories. Coordination through cooperative power pools provided economies of scale and scope that ultimately lowered costs for all participant utilities. The principles of coordination pioneered in power pools later became the basis for the centrally organized electricity markets that exist today.[55]

Over time, economists and industry observers came to believe that the natural monopoly status that was the basis of so much of electricity industry regulation no longer applied to generation and instead only applied to the "wires" part of the system. While it would be economically wasteful for multiple companies to install overlapping and competing distribution and transmission lines, the generation and sale of electricity to retail customers could be organized as competitive activities.[56] To encourage fair and open competition, several states eventually restructured individual IOUs into separate companies that invested in either regulated or competitive parts of the industry.

Restructuring actions vary by region and by state, but they are typically characterized by the "unbundling" of ownership and regulation of electricity generation, transmission, distribution, and sales, with large variations in how restructuring is implemented across regions and states.

Congress took an early step toward reintroducing market competition in the generation sector in 1978 when it enacted the Public Utilities Regulatory Policies Act (PURPA).[57] PURPA required utilities to purchase power from qualifying non-utility generators at the utility's avoided cost. This led to a wave of investment in generation by non-utility companies.

A major step toward creating electric markets was Congress' enactment of the Energy Policy Act of 1992 (EPAct 1992), which provided FERC with limited authority to order transmission access for wholesale buyers in procuring wholesale electric supplies.[58, 59, 60] Subsequent FERC actions, including Order No. 888 and Order No. 889, created greater transmission access and facilitated the creation of competitive wholesale electricity markets. These FERC orders increased access to electricity supplies from other utilities for wholesale buyers, including public power and rural cooperative utilities.

Also in the 1990s, several states made regulatory changes introducing retail electric choice programs to allow some customers to choose an electricity provider other than their local utility, and to have electricity delivered over the wires of their local utility.[61] States that allow customer choice are sometimes called "deregulated states," a misnomer, as retail electricity providers and other parts of the industry remain highly regulated. By 1996, at least 41 states, including California, New York, and Texas, had or were considering ending utility monopolies and providing electricity service through retail competition.[62] Some states, notably in the Southeast and in western states besides California, did not embrace this wave of restructuring. In 2000 and 2001, California and the Pacific Northwest experienced severe electricity shortages and price spikes. This California electricity crisis left many states that had not yet implemented restructuring wary of pursuing such reforms. Today, 15 states allow retail electric choice for some or all customers, while 8 states have suspended it, including California, which suspended retail choice for residential customers after the energy crisis.[63]

The net result of these changes to jurisdictions, industry structure, and competitive markets is that the United States today has a patchwork of mechanisms governing the electricity industry and a diverse set of industry participants. Regulation of the industry continues to evolve as new technologies, policies, and business realities emerge.

Laws and Jurisdictions

Government oversight and regulation of the electricity industry centers on the concurrent needs to

- Ensure that safe and adequate electricity service is provided at just and reasonable rates
- Protect the public interest
- Enable the financial health of the system, such as ensuring that service providers can attract the investments needed to continue providing this essential public service
- Play a beneficial role in diminishing the impact of negative externalities, such as ensuring that industry activities are not inadvertently causing hardship to neighboring communities or the environment.

Governmental Actors

The responsibility for regulating and overseeing the numerous actors that encompass the electricity industry and the activities they carry out is vested in multiple government officials. These authorities span Federal, state, local, and tribal governments. The jurisdictional relationship between the actors is shown in Figure A-5 and is explained further on the following page.

Figure A-5. Broad Overview of Jurisdictional Roles in the Electricity Industry[64]

Federal Jurisdiction (FERC, DOI, DOE, EPA, NRC, others)	**State Jurisdiction** (PUC, policymakers, enviro/energy agencies)	**Local Jurisdiction** (Local governing bodies)	**Tribal Jurisdiction** (Tribal utility authorities)
Generation siting (DOI, EPA)	Generation siting (PUC, policymakers, enviro agencies)	Generation siting	Generation siting
Limited interstate transmission siting (DOE, FERC, DOI)	Interstate transmission siting (PUC, policymakers, enviro agencies)	Interstate transmission siting	Interstate transmission siting
Environmental impacts (DOE, EPA, USDA, DOI, others)	Environmental impacts (enviro agencies)	Environmental impacts	Environmental impacts
M&A for regulated utilities (FERC, DOJ, SEC, FTC)	M&A for regulated utilities (PUC, policymakers)	Zoning approval	Govern operational market, planning activities of tribal utilities and have a say in the majority of activities that occur on tribal lands
Resource adequacy in RTO/ISO markets	Resource adequacy & generation mix (PUC, legisilatures)	Local elected or appointed boards govern public power and cooperatives. These boards typically oversee the majority of public power/ coop activities	
Managing system operation and planning challenges arising from an increase in devices that can participate at both the wholesale and retail level	Managing system operation and planning challenges arising from an increase in devices that can participate at both the wholesale and retail level		
Interstate transmission commerce (FERC)	Retail sales to end users (PUC)		
Interstate wholesale commerce (FERC)	Utility planning (PUC, policymakers)		
Hydro licensing and safety (FERC)	State energy goals/policies (policymakers)		
Nuclear plant oversight (NRC)	Power plant safety standards (OSHA)		
Bulk system reliability (FERC/ NERC)			
Power plant safety standards (OSHA)			

● Indicates Federal–State–Local–Tribal Jurisdictional Ambiguity

● Indicates Federal–State Jurisdictional Ambiguity

Jurisdictional responsibility of the electricity industry is divided between Federal, state, local, and tribal jurisdictions. Several issues, such as generation siting, transmission siting, and environmental planning, span all of the four jurisdictions. Federal and state jurisdictions overlap in planning, resource adequacy, and mergers and acquisitions for regulated utilities. Other areas, such as interstate transmission commerce and retail sale to end users, are regulated by the Federal Government (FERC) or the states (public utility commissions), respectively.

Acronyms: Department of Agriculture (USDA); Department of Energy (DOE); Department of the Interior (DOI); Department of Justice (DOJ); Environmental Protection Agency (EPA); Federal Trade Commission (FTC); independent system operator (ISO); North American Electric Reliability Corporation (NERC); Nuclear Regulatory Commission (NRC); Occupational Safety and Health Administration (OSHA); public utility commission (PUC); regional transmission organization (RTO); Securities and Exchange Commission (SEC).

Federal Actors

At the Federal level, FERC carries out the vast majority of the economic Federal regulatory responsibilities pertaining to the electricity industry, primarily regulating transmission and wholesale sales in interstate commerce. In addition, other Federal authorities are involved with various aspects of regulation or oversight; their responsibilities are wide ranging and relate to environmental protection, land use, anti-trust protection, and transmission siting.

Federal Ratemaking

The Federal Energy Regulatory Commission (FERC) is the Federal Government agency responsible for overseeing rates for wholesale sales of electricity and transmission in interstate commerce. Sections 205 and 206 of the Federal Power Act require FERC to assure that the rates charged for transmission and wholesale sales are "just and reasonable" and do not unduly discriminate against any customers or provide preferential treatment. Initially, all FERC rate regulation was based on the cost of service, but that policy has evolved. FERC continues to employ the cost-of-service approach for transmission service. For wholesale power sales, the primary means for setting "just and reasonable" wholesale electricity rates are through competitive mechanisms, subject to market rules to address market power.

State, Local, and Tribal Actors

At the state level, the electricity industry is regulated by state public utility commissions (PUCs), state environmental agencies, and other parts of state government, such as governors, legislatures, and state energy offices.

State governors and legislatures establish laws or standards that impact the electricity industry, such as renewable portfolio standards, and state environmental agencies implement state and some Federal environmental laws and regulations and thus have jurisdiction on electricity.

PUCs in the states, territories, and the District of Columbia regulate IOUs. State laws in a handful of states also give PUCs jurisdiction over public power and cooperatives.[65] PUCs regulate all matters of IOU distribution (rates, capital expenditures, cyber security, reliability, demand-side resources, and the wholesale purchase process) and usually site transmission and generation projects; they also oversee generation choices in non–regional transmission organization (RTO)/independent system operator (ISO) states and oversee retail competition in those states that allow it.

State Retail Rate Setting

State public utility commissions (PUCs) review and set retail rates for investor-owned utilities (IOUs). In states with retail competition, rates only include the costs of the distribution of electricity, while prices for electricity generation are determined competitively. In states that have not restructured their utility industry, retail rates set by PUCs include the recovery of generation, transmission, and distribution costs that utilities incurred to serve their ratepayers.

The underlying mandate of the PUC rate-setting process is to provide affordable and reliable electricity to consumers while ensuring that IOUs are given the opportunity to recoup their costs and earn a reasonable return on their investment. Under cost-of-service regulation, PUCs calculate utility revenue requirements as the sum of (1) rate base times allowed rate of return plus (2) utility operating expenses. The rate base consists of the depreciated cost of a utility's assets. Based on the revenue requirement, rates for each consumer class are determined.[i]

A few states also grant PUCs the authority to regulate rates for public power utilities, but in most cases rates for public power utilities are set by the utility's governing body, for example, a city council or other local authority. Rates for members of rural cooperatives are set by the cooperative's governing board.[j]

[i] A more detailed discussion on different charges for consumers is included in Chapter II (*Maximizing Economic Value and Consumer Equity*).

[j] M. J. Bradley & Associates LLC, *Public Utility Commission Study* (Charlottesville, VA: SRA International, Inc., and Environmental Protection Agency, March 2011), https://www3.epa.gov/airtoxics/utility/puc_study_march2011.pdf.

Federal and State Jurisdictional Responsibilities

The current jurisdictional division of regulatory authority in the electricity sector between the Federal Government and the states, codified in the FPA and interpreted by subsequent Supreme Court and lower court decisions, is the result of the evolution of a regulatory scheme that was originally governed predominantly by state and local agencies. The FPA established an affirmative grant of authority to the Federal Government to regulate wholesale sales and transmissions of electricity in interstate commerce, but the FPA also attempts to draw a "bright line" where that exclusive authority ends and the state's authority to regulate other matters (principally facilities used in the generation and distribution of electric power, as well as retail sales of electricity) begins.

The "bright line" in the FPA uses factors such as transaction and customer type (wholesale v. retail), facility type (generation v. transmission v. distribution), geography (interstate commerce v. intrastate commerce), and regulatory action (e.g., rate regulation v. facility permitting) to divide exclusive regulatory responsibilities between Federal and state regulators. Congress has chosen different approaches for defining Federal regulatory responsibilities and the role of the states in other energy and energy-related statutes, however. The principal differences in approach include the following: (1) while the FPA contemplates exclusive authority for each regulator, with implicit opportunities for cooperative federalism, other Federal statutes explicitly provide for shared authority (sometimes called "cooperative federalism"); and (2) while the FPA provides the Federal Government with limited authority over energy facility siting or generation facilities in general (FERC has jurisdiction over siting hydro), leaving such matters mostly to the states, other Federal statutes, such as the Natural Gas Act, provide for Federal authority over facility siting.[66]

However, new and emerging technologies that are gaining an increasing presence throughout the electricity system today have significantly different operational characteristics and attributes than those that existed when the FPA and its jurisdictional "bright line" were written, and different characteristics than those that existed as that jurisdictional line developed over the ensuing decades. For DG, no clear delineation exists between wholesale and retail jurisdiction as power flows from generation through delivery to ultimate consumption. Instead, new DER (including energy storage) can be interconnected to either the FERC-jurisdictional, high-voltage transmission grid or the state-jurisdictional, low-voltage local distribution system (or behind the customer's meter). In addition, these resources, along with the other new and advanced technologies noted above, can provide (or enable DR that can provide) several kinds of wholesale and retail grid services, with benefits that extend across the traditional generation, transmission, and distribution classifications.

Tensions between Federal and state regulatory jurisdiction over the electricity system have played out in the courts recently. From the October Term of 2014 to the October Term of 2015, the Supreme Court heard three cases involving FERC jurisdictional issues, an atypical number for a single year. The Court's decisions to hear these cases reflect, in part, the growing complexity of regulating the electricity industry, but also point to uncertainty about statutes that regulate services that are increasingly converging with the electricity industry, like natural gas and telecommunications. Two of these cases, the recent *FERC v. Electric Power Supply Association*[67] and *Hughes v. Talen Energy Marketing*[68] decisions, provide examples of the courts applying the FPA's jurisdictional division to new sets of technology and market challenges. In both of those cases, the Court decided generally in favor of the broader view of the Federal role. *FERC v. Electric Power Supply Association*—relating to FERC's Order No. 745—confirmed FERC's authority under the FPA to determine compensation for DR that is bid into the organized wholesale market.

Major Federal Laws Pertaining to the Electricity Industry

While the FPA is the enabling legislation providing the FPC (and now FERC) its authority over portions of the electricity industry, additional laws and rules have further defined the legal landscape governing the electricity system. Overall, these laws and regulations can be broken into two separate categories: electricity industry–related and environmental.

The Federal Water Power Act, enacted in 1920, created the FPC (now FERC) to encourage the development of hydroelectric generation facilities by non-Federal entities. The 1935 FPA expanded the Commission's regulatory jurisdiction to include rates, terms, and conditions of service for interstate electricity transmission and wholesale electricity sales, but left regulation of generation, distribution, and intrastate commerce to state and local governments.[69] This set up the "bright line"[k] between Federal authority over wholesale rates and state and local authority over retail rates.

The utility industry of the early 1900s often relied on holding companies—a financial structure where a parent company would hold the financial stocks and bonds of subsidiary utilities—to improve financial performance and seek economies of scale. Though these companies provided cost savings that contributed to the growth of the utility industry, their complex financial structures enabled companies to subsidize their unregulated business activities with earnings from regulated activities. In response, Congress passed the Public Utility Holding Company Act in 1935, which reduced the role of holding companies in the industry and allowed closer regulatory scrutiny of utilities.[70]

PURPA (1978), passed as part of the National Energy Act, was one of the major reformations of the governance of the electricity industry. Utilities were required to purchase power from qualifying facilities at the utilities' incremental cost of producing or purchasing alternative electricity, which is now known as "avoided cost."[71] The right to sell the power at avoided cost, combined with the exemption from several state and Federal regulations, "created a new and rapidly expanding nonutility generation sector of the electric power industry."[72] Qualifying facilities fall into two categories: (1) cogeneration facilities without any size limitations and (2) small power production facilities, which use biomass, waste, or renewable resources and which have a

[k] The term "bright line" was coined by the Supreme Court in *Federal Power Commission v. Southern California Edison Co.* in 1964.

generating capacity of no more than 80 megawatts. PURPA also required states (and utilities not regulated by states, such as public power and rural cooperative utilities) to conduct proceedings to consider charging cost-of-service rates for different customer classes; eliminating declining block pricing;[l] using time-of-day, seasonal, or interruptible rates; and implementing other retail utility policies.

The Energy Policy Act of 1992 (EPAct 1992) implements many of the provisions of the National Energy Strategy proposed by the Department of Energy (DOE) in February 1991.[73] EPAct 1992 authorized FERC to order transmission-owning utilities to provide transmission services to third parties on a case-by-case basis and adopted reforms to the Public Utility Holding Company Act of 1935, both of which supported increased competition in wholesale electricity markets. EPAct 1992 also included a wide variety of energy efficiency measures, such as requiring states to establish minimum commercial building energy codes and consider voluntary minimum residential codes and equipment standards for commercial heating and air-conditioning equipment, electric motors, and lamps. As a result of the incentives offered through EPAct 1992, several Native Nations developed alternative energy projects on their lands. The Renewable Electricity Production Tax Credit for wind, biomass, landfill gas, and other renewable sources was also first passed in EPAct 1992, and has been renewed several times since then.[74] As of May 2016, the Production Tax Credit provided an inflation-adjusted tax credit worth \$0.023/kWh to qualifying electricity production from wind, closed-loop biomass, and geothermal, as well as a \$0.012/kWh credit for open-loop biomass, landfill gas, municipal solid waste, qualified hydro, and marine and hydrokinetic.[75]

The Energy Policy Act of 2005 (EPAct 2005) addressed several major areas of the electricity industry.[76] EPAct 2005 pared back the must-purchase clause contained in PURPA by giving FERC the authority to allow utilities in regions with competition not to use the avoided-cost principle. The legislation also gave FERC responsibility for mandatory reliability standards and allowed the agency to certify an electric reliability organization to develop and enforce those standards. The North American Electric Reliability Corporation (NERC) is the designated electric reliability organization for North America and oversees eight regional reliability entities in the United States, Canada, and Baja California (Mexico). NERC is a not-for-profit corporation that, through a stakeholder process, develops and enforces mandatory electric reliability standards under FERC oversight in the United States.

EPAct 2005 also tasked DOE with issuing periodic studies of transmission congestion, and following the appropriate evaluation of transmission congestion and alternatives, authorizes DOE to designate National Interest Electric Transmission Corridors where there are electricity transmission capacity constraints or congestion. For projects located in these corridors, FERC has "backstop authority" to authorize transmission siting.[77] FERC was also given responsibility to provide rate incentives to promote transmission investment.

EPAct 2005 also increased the Investment Tax Credit, which has been renewed several times, including in the Omnibus Appropriations Act of 2015.[78] Currently, the Investment Tax Credit is 30 percent for solar, fuel cells, and small wind and 10 percent for geothermal, microturbines, and combined heat and power.[79] Additionally, EPAct 2005 provided grants for nuclear energy research and development and also implemented a \$0.018/kWh production credit for modern nuclear energy plants (1) whose design was approved by the Nuclear Regulatory Commission after December 1, 1993, (2) that started construction by January 2014, and (3) that are placed in commercial operation by 2021. EPAct 2005 also created the Title XVII Loan Program, which allows DOE to provide "guarantee loans that support early commercial use of advanced technologies, if there is reasonable prospect of repayment by the borrower."[80]

Other key laws and orders in the electricity industry are included in Table A-2, and key electricity industry–related environmental laws and regulations are included in Table A-3.

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[l] Effectively a bulk-purchase discount for large electricity consumers, making marginal increments of electricity cheaper as consumption rises.

Table A-2. Additional Key Electricity Industry Laws and Orders

Name	Year	Major Provisions
Atomic Energy Act	1954	• Established Federal regulatory authority over civilian uses of nuclear materials and facilities exercised through the Nuclear Regulatory Commission • Delineated Federal/state jurisdiction for nuclear material and facilities: licensing of nuclear plant construction and operation as well as waste disposal are exclusively in the Federal domain. States retain oversight of generation planning by vertically integrated utilities (e.g., questions of whether or not to construct nuclear facilities in the first place).
Price Anderson Act	1957	• Facilitated the development of nuclear-powered generating capacity by establishing a program for covering claims of members of the public if a major accident occurred at a nuclear power plant and providing a ceiling on the total amount of liability for nuclear accidents.
National Energy Act	1978	• Passed in response to oil shortages in the 1970s and the increased reliance on imported oil, which was seen as a threat to national security[m] • Legislation included the Natural Gas Policy Act of 1978, the Public Utility Regulatory Policies Act (PURPA), the Energy Tax Act, the Powerplant and Industrial Fuel Use Act, and the National Energy Conservation Policy Act.[n]
Energy Independence and Security Act	2007	• Strengthened lighting energy-efficiency standards • Added Section 1705 to the loan guarantee program, allowing subsidized loans to commercial facilities • Called for coordination to develop a framework for smart grid interoperability standards (National Institute of Standards and Technology).
American Recovery and Reinvestment Act	2009	• Funded $31 billion in energy efficiency and renewable energy, energy infrastructure, and made other major investments in energy administered by DOE.[o]
FERC Order 1000	2011	• Requires regional and interregional transmission planning; mandates that the planning process consider transmission needs driven by public policy requirements • Requires regional and interregional cost allocation methods that satisfy six allocation principles • Eliminates the Federal right of first refusal in FERC jurisdictional tariffs and agreements.[p]

In addition to the FPA, the Federal Water Power Act, the Public Utility Holding Company Act of 1935, PURPA, EPAct 1992, and EPAct 2005, which are discussed in the above section, these laws and orders have played key roles in shaping the electricity industry.

[m] Julia Richardson and Robert Nordhaus, "The National Energy Act of 1978," *Natural Resources & Environment* 10, no. 1 (1995): 62, http://www.jstor.org/stable/40923435.

[n] Julia Richardson and Robert Nordhaus, "The National Energy Act of 1978," *Natural Resources & Environment* 10, no. 1 (1995): 62–86, http://www.jstor.org/stable/40923435.

[o] "Recovery Act," Department of Energy, accessed July 29, 2016, http://www.energy.gov/recovery-act.

[p] EPSA Analysis: ICF International, *Impacts of the Power Sector Transformation on Jurisdictional Boundaries, Planning, and Rate Design* (Fairfax, VA: ICF International, July 2016), 11.

Table A-3. Key Electricity Industry-Related Environmental Laws and Regulations

Name	Year	Major Provisions
Clean Air Act	1970	• Authorized comprehensive Federal and state regulation of stationary pollution sources, including power plants[q] • Provided for National Ambient Air Quality Standards, State Implementation Plans, New Source Performance Standards, and National Emission Standards for Hazardous Air Pollutants[r] • Requires states to decide what pollution reductions will be required from particular sources to address National Ambient Air Quality Standards, and requires states to submit State Implementation Plans.[s]
National Environmental Policy Act	1970	• Requires Federal agencies to review the environmental consequences of a proposed project before granting approval.[t] Agencies prepare statements on the environmental impact of a proposed project (Environmental Impact Statement or Environmental Assessment), considering the views of the public and of other Federal, state, and local agencies, and make the report publicly available.[u]
Clean Water Act	1972	• Established regulations for discharging pollutants into water,[v] which includes wastewater discharges from the power sector (such as cooling water, wastewater from coal ash handling, and wastewater from pollution control equipment) • The Steam Electric Effluent Limitations Guidelines—promulgated under the Clean Water Act—were updated in 2015.
Resource Conservation and Recovery Act	1976	• Provides EPA with the authority to regulate hazardous waste,[w] including management of power sector waste, such as coal ash • The Coal Combustion Residuals rule—promulgated under the Resource Conservation and Recovery Act—was finalized in 2015.
New Source Performance Standards	1979	• EPA rule governing sulfur dioxide emissions from coal power plants[x] • Effectively required flue gas desulfurization on all new coal plants.

Beginning with the Clean Air Act in 1970, major environmental laws and regulations have impacted the electric industry in key ways.

[q] "Evolution of the Clean Air Act," Environmental Protection Agency, accessed July 28, 2016, https://www.epa.gov/clean-air-act-overview/evolution-clean-air-act.

[r] "Evolution of the Clean Air Act," Environmental Protection Agency, accessed July 28, 2016, https://www.epa.gov/clean-air-act-overview/evolution-clean-air-act.

[s] "Summary of the Clean Air Act," Environmental Protection Agency, accessed October 13, 2016, https://www.epa.gov/laws-regulations/summary-clean-air-act.

[t] "Summary of the National Environmental Policy Act," Environmental Protection Agency, accessed October 13, 2016, https://www.epa.gov/laws-regulations/summary-national-environmental-policy-act.

[u] Executive Office of the President, Council on Environmental Quality (CEQ), *A Citizen's Guide to the NEPA: Having Your Voice Heard* (Washington, DC: Executive Office of the President, CEQ, December 2007), http://www.blm.gov/style/medialib/blm/nm/programs/planning/planning_docs.Par.53208.File.dat/A_Citizens_Guide_to_NEPA.pdf.

[v] "Summary of the Clean Water Act," Environmental Protection Agency, accessed October 13, 2016, https://www.epa.gov/laws-regulations/summary-clean-water-act.

[w] "Summary of the Resource Conservation and Recovery Act," Environmental Protection Agency, accessed October 13, 2016, https://www.epa.gov/laws-regulations/summary-resource-conservation-and-recovery-act.

[x] D. Hercher, "New Source Performance Standards for Coal-Fired Electric Power Plants," *Ecology Law Quarterly* 8, no. 4 (March 1980): 748–61, http://scholarship.law.berkeley.edu/cgi/viewcontent.cgi?article=1174&context=elq.

Name	Year	Major Provisions
Clean Air Act Amendments	1990	• Encouraged market-based principles to pollution control, such as emissions trading[y] • Requires EPA to regulate more than 180 specified hazardous air pollutants[z] and set up specific procedures to determine whether the air pollution regulations would apply to power plants that run on fossil fuels[aa] • Established the U.S. Acid Rain Program, the world's first large-scale emissions cap-and-trade system to reduce air pollution. The program set a permanent cap on annual sulfur dioxide emissions from the power sector.
Cross-State Air Pollution Rule	2011	• Replaced the Clean Air Interstate Rule starting on January 1, 2015 • Requires states to reduce power plant emissions that contribute to ozone and fine particle pollution in downwind states.[ab]
Mercury and Air Toxics Standard	2011	• EPA rule limiting mercury and other toxic pollution from power pants.[ac]
Carbon Pollution Standards and Clean Power Plan	2015	• In 2015, EPA finalized the Carbon Pollution Standards rule establishing carbon dioxide emission standards for new fossil fuel-fired generators under Clean Air Act section 111(b). • Also in 2015, EPA finalized the Clean Power Plan, a rule to reduce carbon dioxide emissions from existing fossil fuel-fired generators under Clean Air Act section 111(d)[ad] The rule establishes final emission guidelines for states to follow in developing plans to reduce greenhouse gas emissions from existing fossil fuel–fired electric generating units, leaving states with considerable discretion to choose the approach.[ae] • As of January 2016, implementation of the Clean Power Plan has been stayed by the Supreme Court pending the outcome of litigation.[af] • EPA regulation of greenhouse gas emissions followed from the 2007 Supreme Court decision in Massachusetts v. EPA that greenhouse gases are air pollutants under the Clean Air Act, and the 2009 EPA finding that the current and projected concentrations of six key greenhouse gases in the atmosphere endanger the public health and welfare, a prerequisite for implementing greenhouse gas emissions standards.[ag]

[y] "1990 Clean Air Act Amendment Summary," Environmental Protection Agency, accessed July 28, 2016, https://www.epa.gov/clean-air-act-overview/1990-clean-air-act-amendment-summary.

[z] Michigan v. EPA., 135 S. Ct. 2699, 2704, 192 L. Ed. 2d 674 (2015) (citing 42 U.S.C. § 7412(b)).

[aa] Michigan v. EPA., 135 S. Ct. 2699, 2705, 192 L. Ed. 2d 674 (2015).

[ab] "Cross-State Air Pollution Rule (CSAPR) Basics," Environmental Protection Agency, accessed October 13, 2016, https://www.epa.gov/csapr/cross-state-air-pollution-rule-csapr-basics.

[ac] "EPA Announces Mercury and Air Toxics Standards (MATS) for Power Plants – Technical Information," Environmental Protection Agency, December 21, 2011, https://www.epa.gov/mats/epa-announces-mercury-and-air-toxics-standards-mats-power-plants-technical-information.

[ad] Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 80 Fed. Reg. 64662 (Oct. 23, 2015).

[ae] Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 80 Fed. Reg. 64662 (Oct. 23, 2015).

[af] Order in Pending Case, Chamber of Commerce, et al. v. EPA, et al., 577 U.S. (February 9, 2016), http://www.supremecourt.gov/orders/courtorders/020916zr3_hf5m.pdf.

[ag] "Endangerment and Cause or Contribute Findings for Greenhouse Gases under the Section 202(a) of the Clean Air Act," Environmental Protection Agency, accessed January 4, 2017, https://www.epa.gov/climatechange/endangerment-and-cause-or-contribute-findings-greenhouse-gases-under-section-202a.

Federal Authorities, Policies, and Frameworks for Electric Grid Resilience and Security

The Federal Government plays a key role in enhancing the resilience and security of the grid through diverse efforts, including research and development, information sharing, the establishment and enforcement of utility performance standards, and the coordination of response resources. Presidential policy directives and congressional legislation have outlined specific authorities for the Federal Government in recognition of the importance of the electricity sector—and supporting energy sectors—for national and economic security. This section describes select Federal policies and frameworks guiding national resilience and security efforts, as well as selected challenges in fulfilling Federal roles to protect critical electricity infrastructure.

Selected Authorities for the Energy Sector

Defense Production Act: Ensures timely availability of resources for national defense and civil emergency preparedness and response, including energy-related assets. (1950)

Energy Policy and Conservation Act: Directs the Secretary of Energy to establish, operate, and maintain the Strategic Petroleum Reserve (1975), which includes the Northeast Gasoline Supply Reserve, and provides for the Presidentially-directed drawdown of those reserves. Also authorizes the Secretary to establish and manage the Northeast Home Heating Oil Reserve. (2000 as amended)

Federal Energy Administration Act: Grants the Department of Energy (DOE) the authority to collect, evaluate, and analyze energy information from facilities or businesses operating in any phase of energy supply or major energy consumption. (1974)

Federal Power Act: Provides the Secretary of Energy authority in time of emergency to order temporary interconnections of facilities and the generation, delivery, interchange, or transmission of electric energy necessary to meet an emergency. (1935, 2015 as amended by FAST Act, as defined below) The Federal Power Act also gives FERC the authority to order compliance with reliability standards. (1935, 2005 as amended by Energy Policy Act [EPAct]) In addition, the **Fixing America's Surface Transportation Act (FAST) Act** amended the Federal Power Act empowering the President to declare a grid security emergency in the face of an electromagnetic pulse, cyber or geomagnetic disturbances, and physical threats and, in doing so, enabling the Secretary of Energy to (1) direct users and operators of electricity assets to undertake such actions as are necessary to ensure the reliability of critical electric infrastructure, and (2) share classified information as necessary to mitigate effects of the grid security emergency. It also allows the Federal Energy Regulatory Commission to provide a mechanism for any affected entities to recover related costs. (2015)

Natural Gas Policy Act: Authorizes DOE to allocate supplies of natural gas to help alleviate an existing or imminent, Presidentially-declared, severe natural gas shortage that would endanger the supply of gas for high-priority uses. (1978)

Selected Authorities for the Energy Sector (continued)

Stafford Disaster Relief and Emergency Assistance Act: The Stafford Act[ah] gives the Federal Government its authority to provide response and recovery assistance in a major disaster. (1988). The Stafford Act identifies and defines the types of occurrences and conditions under which disaster assistance may be provided. Under the law, the declaration process[ai] remains a flexible tool for providing relief where it is needed. Designates the Federal Emergency Management Agency (FEMA) as the lead for Federal emergency response; FEMA may require other Federal agencies to provide resources and personnel to support emergency and disaster assistance efforts. DOE is the sector-specific agency for energy under this framework.

Executive Order 12656—Assignment of Emergency Preparedness Responsibilities: Assigns preparedness responsibilities to Federal agencies and requires agencies to be prepared to respond adequately to all national security emergencies, including developing emergency plans. (1988)

Homeland Security Presidential Directive 5 (HSPD-5): Establishes a single, comprehensive National Incident Management System under the purview of the Department of Homeland Security, under which all other Federal agencies provide their cooperation, resources, and support. The directive also provides direction for Federal assistance to state and local authorities. (2003)

Presidential Policy Directive 8 (PPD-8)—National Preparedness: Replaces prior national planning directives and takes an "all-of-Nation" approach to prepare for a wide range of threats and emergencies. National Planning Frameworks—coordinating structures of key Federal agencies and other stakeholders—have been established around five mission areas: prevention, protection, mitigation, response, and recovery. (2011)

Presidential Policy Directive 21 (PPD-21)—Critical Infrastructure Security and Resilience: Establishes shared responsibility for strengthening critical infrastructure security across the Federal Government. PPD-21 highlights the role of the national physical and cyber coordinating centers in enabling successful critical infrastructure security and resilience outcomes.[aj] Designates critical infrastructure sectors and sector-specific agencies, notably DOE as the sector-specific agency for the energy sector. (2013)

[ah] Robert T. Stafford Disaster Relief and Emergency Assistance Act, 42 U.S.C. § 5121 (2007).

[ai] "The Robert T. Stafford Disaster Relief and Emergency Assistance Act, 42 U.S.C. §§ 5121-5207 (the Stafford Act) §401 states in part that: 'All requests for a declaration by the President that a major disaster exists shall be made by the Governor of the affected State.' A State also includes the District of Columbia, Puerto Rico, the Virgin Islands, Guam, American Samoa, and the Commonwealth of the Northern Mariana Islands. The Republic of Marshall Islands and the Federated States of Micronesia are also eligible to request a declaration and receive assistance through the Compacts of Free Association." See "The Disaster Declaration Process," Federal Emergency Management Agency, accessed September 23, 2016, https://www.fema.gov/disaster-declaration-process.

[aj] Department of Homeland Security (DHS), *Supplemental Tool: Connecting to the NICC and NCCIC* (Washington, DC: DHS, 2013), 1, https://www.dhs.gov/sites/default/files/publications/NIPP-2013-Supplement-Connecting-to-the-NICC-and-NCCIC-508.pdf.

Planning and Coordination Frameworks

Federal policy directives and legislation address the evolving threats and institutional vulnerabilities of the Nation's critical infrastructure by defining roles and responsibilities for national grid *resilience* and security. Homeland Security Presidential Directive (HSPD)-7, Presidential Policy Directive (PPD)-8, and PPD-21 laid the groundwork for the key coordinating bodies and a national approach to plan for events.

Joint United States–Canada Electric Grid Security and Resilience Strategy

In December 2016, the Federal Governments of the United States and Canada released the "Joint United States-Canada Electric Grid Security and Resilience Strategy," a collaborative effort between the two nations intended to strengthen the security and resilience of the U.S. and Canadian electric grids from all adversarial, technological, and natural hazards and threats. The Strategy addresses the vulnerabilities of the two countries' respective and shared electric grid infrastructure, not only as an energy security concern, but for reasons of national security. Because the electric grid is complex, vital to the functioning of modern society, and dependent on other infrastructure for its function, the United States and Canada developed the Strategy under the shared principle that security and resilience require increasingly collaborative efforts and shared approaches to risk management.

The Strategy organizes joint approaches to protect today's grid, manage contingencies by enhancing response and recovery capabilities, and cultivate a more secure and resilient future grid. As an expression of shared intent and approach, the Strategy organizes joint efforts to manage current and future security challenges. Three strategic goals underpin the effort to strengthen the security and resilience of the electric grid:

Protect Today's Electric Grid and Enhance Preparedness: A secure and resilient electric grid that protects system assets and critical functions and is able to withstand and recover rapidly from disruptions is a priority for the governments of both the United States and Canada.

Manage Contingencies and Enhance Response and Recovery Efforts: The Strategy sets out a shared approach for enhancing continuity and response capabilities, supporting mutual aid arrangements, such as cyber mutual assistance across a diverse set of stakeholders, understanding interdependencies, and expanding available tools for recovery and rebuilding.

Build a More Secure and Resilient Future Electric Grid: The United States and Canada are working to build a more secure and resilient electric grid that is responsive to a variety of threats, hazards, and vulnerabilities. To achieve this, the electric grid will need to be more flexible and agile, with an architecture into which new technologies may be readily incorporated.[ak]

The Strategy will be implemented through the U.S. and Canadian Action Plans, which detail specific steps and milestones for achieving the Strategy's goals within their respective countries.[al] These documents are intended to guide future activity within areas of Federal jurisdiction, with full respect for the different jurisdictional authorities in both countries.

[ak] Governments of the United States and Canada, *Joint United States-Canada Electric Grid Security and Resilience Strategy* (Washington, DC: Executive Office of the President of the United States and Government of Canada, December 2016), https://obamawhitehouse.archives.gov/sites/whitehouse.gov/files/images/Joint_US_Canada_Grid_Strategy_06Dec2016.pdf.

[al] Executive Office of the President, *National Electric Grid Security and Resilience Action Plan* (Washington, DC: Executive Office of the President, December 2016), https://obamawhitehouse.archives.gov/sites/whitehouse.gov/files/images/National_Electric_Grid_Action_Plan_06Dec2016.pdf.

Under HSPD-7 and then PPD-21, the National Infrastructure Protection Plan set out a number of partnership structures for coordination and information sharing within and across sectors, including electricity. Some of the formal coordination and information-sharing councils available to the electricity subsector include the following:

- **Electricity Subsector Coordinating Council:** Represents the interests of the industry and is composed of electric utility industry executives. It is the principal mechanism for private-sector owners and operators to work collaboratively with the government under a structured and protected framework that allows open dialogue. There is a counterpart subsector coordinating council for the oil and natural gas subsector. Numerous task forces and subcommittees have worked on supply-chain concerns, interdependencies, and coordination with other sectors. The Electricity Subsector Coordinating Council is also a critical coordination mechanism for information sharing during and after incidents.
- **Energy Government Coordinating Council:** This government counterpart to the Electricity Subsector Coordinating Council is jointly led by DOE and the Department of Homeland Security (DHS), with membership from all levels of government and international partners.

These structures collectively serve as a means of sharing information, best practices, research needs, and other critical infrastructure security information, such as information about interdependencies, across sectors.

Additionally, PPD-8 calls for the development of a National Planning System to integrate planning across all levels of government and the private sector. The intent is to provide a flexible approach to prevent, protect, mitigate, respond, and recover from an event. The National Planning System includes the following:[81, 82]

- National planning frameworks describing the key roles and responsibilities to deliver the core capabilities required for the key mission areas: prevent, protect, mitigate, respond, and recover
- Federal Interagency Operational Plans for each mission area to provide further details regarding roles and responsibilities, specify critical tasks, and identify requirements for delivering core capabilities
- Federal department and agency operational plans to implement the Federal Interagency Operational Plans
- Comprehensive planning guidance to support planning by local, state, tribal, and territorial governments; the private sector; and others.

PPD-8 also outlines five frameworks to maintain proper support from the Federal Government by working through states to assist affected local jurisdictions or organizations. The five frameworks divide efforts into rational disciplines of competence—prevention, protection, mitigation, response, and recovery. The combined frameworks shape efforts to prepare our Nation for emergencies stemming from all hazards.

The National Response Framework and its Emergency Support Function (ESF)-12 Annex outline much of the joint Federal, state, and private-sector responsibility for response and recovery to energy service disruptions. The ESF-12 Annex characterizes the Federal response as the facilitation of restoration of damaged energy systems and components. For example, DOE may exercise its emergency powers depending on the conditions of certain respective declarations and findings to facilitate restoration and to meet the needs of industry. After an incident, the National Disaster Recovery Framework[83] provides guidance for an expeditious return to a normal way of life. Like the National Response Framework's ESFs, the National Disaster Recovery Framework has Recovery Support Functions. DOE is named as a primary agency in the Recovery Support Function–Infrastructure Systems.

Tools and Technical Assistance

The Federal Government also provides numerous tools and technical assistance to enhance states' and the electric industry's capabilities to operate electricity systems in a secure and resilient manner. Many of these resources help stakeholders understand risks, assess their systems, analyze vulnerabilities, and prioritize mitigation strategies. Below are a few examples:

- DOE's Electricity Subsector Cybersecurity Capability Maturity Model helps entities evaluate, prioritize, and improve their cybersecurity capabilities and allows for a better overall assessment of the cybersecurity posture of the energy sector.[84]
- DHS's Cyber Security Evaluation Tool[85] and the Cyber Resilience Review are complementary and voluntary tools for evaluating industrial control system (ICS) and information technology network practices, and operational resilience and cybersecurity capabilities, respectively.[86]
- DHS's ICS Cyber Emergency Response Team provides resources to critical infrastructure sectors to prevent and recover from cyber attacks. This includes working onsite to help resolve spear phishing campaigns that seem to target ICS/supervisory control and data acquisition (or SCADA) data, including data that could facilitate remote access and control of systems.[87]
- DHS Regional Resiliency Assessment Program conducts regional assessments of the Nation's critical infrastructure, addressing a range of hazards that could have regionally and nationally significant consequences. Argonne National Laboratory completed 56 Regional Resiliency Assessment Program projects during 2009–2014, which addressed a variety of postulated hazards, including tornadoes, ice storms, earthquakes, hurricanes, solar storms, and other threats to the electric sector.
- The National Oceanic and Atmospheric Administration supports Regional Climate Centers, which are able to provide technical assistance and climate data to support risk assessment and decision making by utilities and governments.[88]
- DOE's Office of Energy Policy and Systems Analysis convenes the Partnership for Energy Sector Climate Resilience, through which DOE provides technical assistance for 18 electric utilities that are demonstrating leadership in developing vulnerability assessments and pursuing strategies for investing in climate resilience.

Continued support for tools development and expanding technical assistance resources is increasingly important as changing risks from human-induced actions and natural hazards make risk-based planning more challenging. For example, to credibly account for projected changes in climate, utility planners and regulators need technical assistance in accessing and correctly interpreting climate data at the appropriate time and geographic scales.

Standards and Guidance

As previously discussed, FERC has regulatory authority over the reliability of the bulk power system, overseeing the development and approval of standards set by NERC. FERC can also proactively direct NERC to develop a new or modified reliability standard to address reliability issues identified by FERC. While these standards cover the reliability and security of bulk power assets, NERC has typically designed them with the benefit of the system as a whole in mind, balancing the interests of its stakeholders. In addition to standards, the Federal Government works with stakeholders to develop additional guidance to support risk mitigation strategies across the electric sector.

It is worth noting that NERC's planning standards for electric reliability (e.g., TPL-001-4) and facility ratings standards (e.g., FAC-008-3) require consideration of a broad range of risks to the system. However, assumptions within these standards regarding the frequency and intensity of extreme weather events, for example, do not account for projected changes in climate. Furthermore, transmission planning efforts routinely consider system-wide costs associated with average weather-related loads, rather than accounting for extreme conditions.[89] The practice of using historical data and average conditions undercuts efforts to plan and prepare for threats, such as extreme weather, cyber attacks, or hostile actions, that may have different characteristics in the future.

Within the Commerce Department, the National Institute of Standards and Technology (NIST) develops frameworks, voluntary standards, and other guidance documents to assist electric sector efforts in reliability, resiliency, and security.[90] NIST conveys unique technical requirements for authorizing, monitoring, and managing all methods of remote access to the smart grid information system.[91, 92] The NIST Framework and Roadmap for Smart Grid Interoperability Standards, Release 3.0, is one example of these resources.[93, 94] In addition, in 2014, the NIST released the Framework for Improving Critical Infrastructure Cybersecurity, which includes a set of standards, methodologies, procedures, and processes that align policy, business, and technological approaches to address cyber risks, and incorporates voluntary consensus standards and industry best practices.[95] In 2015, DOE released guidance to help the energy sector establish or align existing cybersecurity risk management programs to meet the objectives of the framework released by NIST.

Several organizations are also actively revising interconnection standards—the rules that prescribe capabilities that technologies like DG must possesses as a precondition to connecting to the electricity system—to better support the reliability, safety, and cost effectiveness of the grid. As technologies subject to interconnection standards increase in number and potential impact on the grid, enhanced Federal support is critical to the timely and robust completion of these standards.

Information Sharing and Threat Analysis

Federal agencies have institutions and programs in place to enhance information sharing and the dissemination of threat analysis to government and industry partners. DHS is responsible for several key infrastructure security programs. The National Infrastructure Coordinating Center and the National Cybersecurity and Communications Integration Center are the national focal points for industry partners to obtain 24/7 situational awareness and integrated actionable information to secure the Nation's physical and cyber critical infrastructure, respectively.[96] During major incidents, the National Infrastructure Coordinating Center and the National Cybersecurity and Communications Integration Center closely coordinate with the Federal Emergency Management Agency to ensure that overall critical infrastructure status and impacts on life and safety are understood throughout the Federal incident response community.[97]

Below are additional examples of government programs available to electric sector participants:

- **DHS Fusion Centers** are information-sharing hubs for Federal, state, local, tribal and territorial agencies and industry to maintain situational awareness at the state and local levels. Fusion centers receive, analyze, and disseminate threat information, providing local perspectives to their partners.[98]
- **DHS Automated Indicator Sharing** is a free program that facilitates the exchange of cyber threat indicators between the Federal Government and parties that opt in to the program through machine-to-machine sharing.[99]
- **DOE's Cybersecurity Risk Information Sharing Program** facilitates the exchange of detailed cybersecurity threat information among electric utilities, the Electricity Information Sharing and Analysis Center, DOE, and several National Laboratories. The program was designed to facilitate the timely bidirectional sharing of unclassified and classified threat information, and to develop situational awareness tools to enhance the sector's ability to identify, prioritize, and coordinate the protection of their critical infrastructure and key resources.
- **Information Sharing and Analysis Organizations** encourage exchange of information to protect critical infrastructure and are supported by sector-specific agencies and DHS in accordance with Executive Order 13691 and PPD-63.

Electricity System Operations, Business Models, and Markets

System Operation

The electricity system of the continental United States does not function as a single, unified grid, but rather is split into three interconnections that each function as independent power systems with limited power flows between them, enabled by DC interconnections between the regional systems. Hawaii and parts of Alaska also operate as independent systems. The goal in operating each of these power systems is to deliver low-cost and reliable electricity. A complex set of institutions, defined by geographic boundaries, accomplishes this goal.

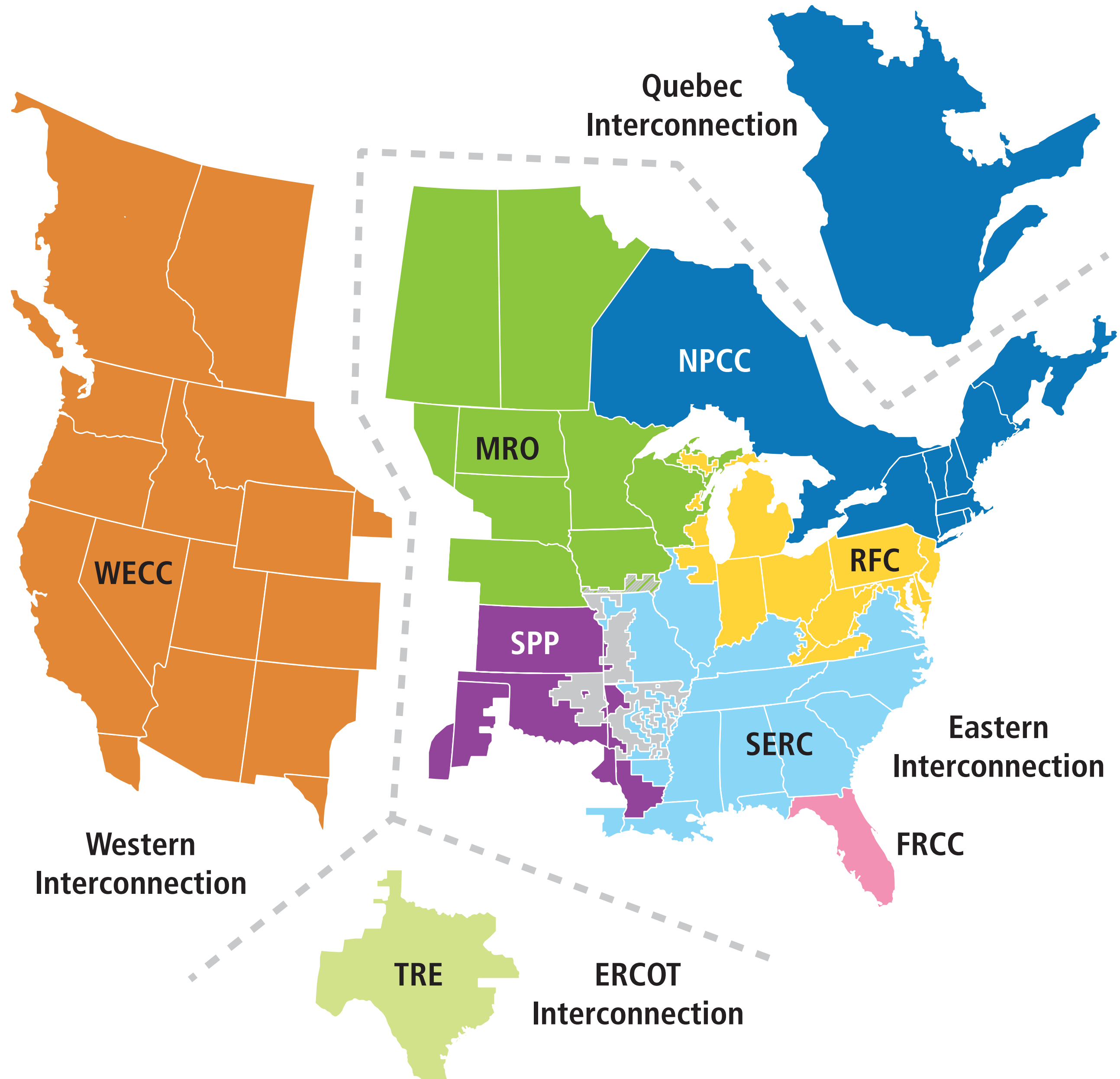
One of the broadest geographic divisions is the regional reliability entity,[am] which develops and enforces standards on behalf of NERC.[an, 100] Figure A-6 shows the three interconnections of the continental United States and the NERC reliability regions.

Providing electricity when and where it is needed is an incredibly complicated engineering process. Unlike most other consumer goods and energy sources, electricity is not stored in large quantities and must be produced at the instant it is needed. It is the job of power system planners and operators to ensure that electricity is produced when and delivered to where it is needed at every moment of every day.

[am] Instead of *entity*, the terms *council* and *organization* are sometimes used to refer to these entities as a group. Individually, their names include entities (e.g., Texas Reliability Entity), councils (e.g., Florida Reliability Coordinating Council), organizations (e.g., Midwest Reliability Organization), corporations (e.g., SERC Reliability Corporation), and pools (e.g., Southwest Power Pool, Inc.).

[an] NERC sets standards for the reliability of the bulk power system. The jurisdiction and authority of NERC is discussed in greater detail in the "Federal Actors" section of this appendix.

Figure A-6. North American Interconnections and Reliability Regions[ao, 101]

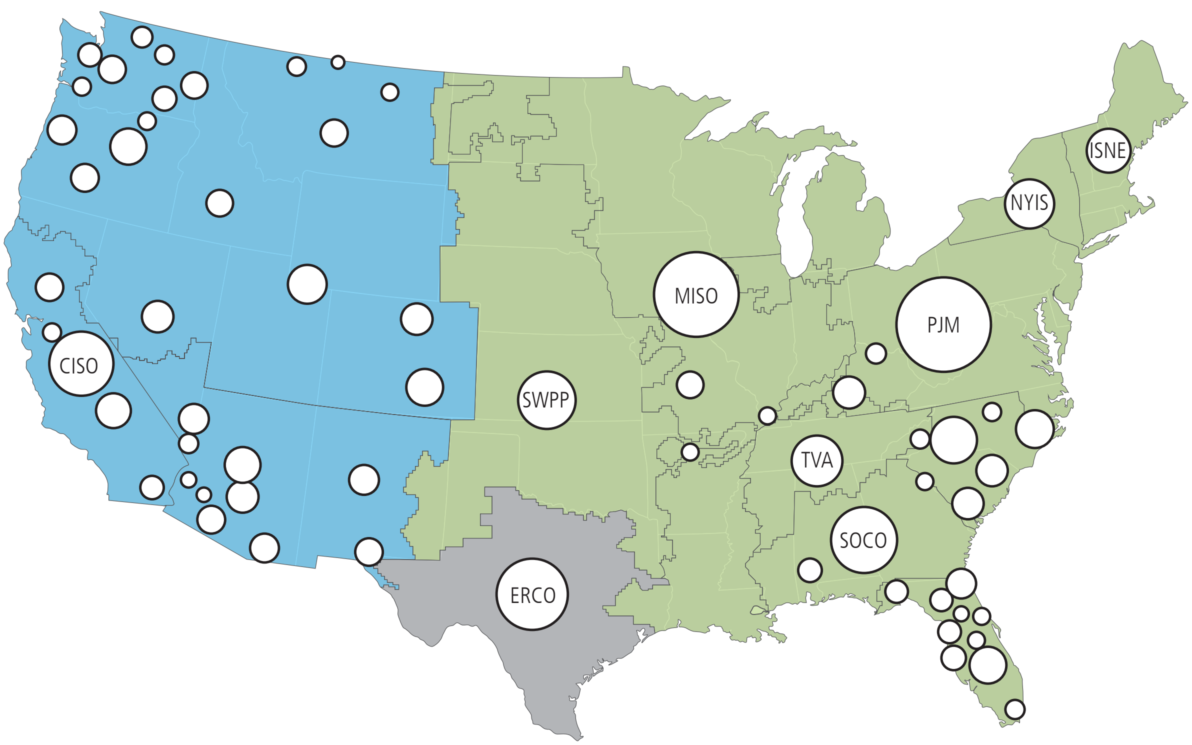


This map shows four North American interconnections, three of which include the United States, and eight NERC reliability regions. The four interconnections include Eastern, Western, Quebec, and the Electric Reliability Council of Texas (ERCOT). The NERC regions include: Florida Reliability Coordinating Council (FRCC), Midwest Reliability Organization (MRO), Northeast Power Coordinating Council (NPCC), ReliabilityFirst (RF), SERC Reliability Corporation (SERC), Southwest Power Pool Regional Entity (SPP RE), Texas Reliability Entity (TRE), and Western Electricity Coordinating Council (WECC).

[ao] This figure is based on information from the North American Electric Reliability Corporation's website, which is the property of the North American Electric Reliability Corporation and is available at http://www.nerc.com/AboutNERC/keyplayers/PublishingImages/NERC_Interconnections_Color_072512.jpg. This content may not be reproduced in whole or any part without the prior express written permission of the North American Electric Reliability Corporation.

The Nation is regionally subdivided into balancing areas, shown in Figure A-7, where balancing authorities operate regions of the grid on a day-to-day basis. Some of these regions overlap precisely with NERC reliability regions, while many others are smaller in geographic extent. On a daily basis, balancing authorities forecast demand, schedule generation supply, and schedule exchanges with neighboring regions. These decisions are generally guided by software-optimization systems that minimize the total cost of meeting demand, subject to operating constraints and reliability criteria. Scheduling generation supply occurs on multiple time horizons, the most important of which include unit commitment (scheduling the availability of a generator days or hours ahead of time) and economic dispatch (providing operating instructions in near real time).

Figure A-7. Electricity System Interconnections and Balancing Areas[102]



The electricity industry includes the three continental United States electricity system interconnections (Eastern, Western, and the Electric Reliability Council of Texas [ERCOT]), and the 66 balancing authorities that are responsible for maintaining a balance between supply and demand within their areas. The location of the balancing area bubbles is approximate, and the size represents a rough indication of the size of the system managed in each area.

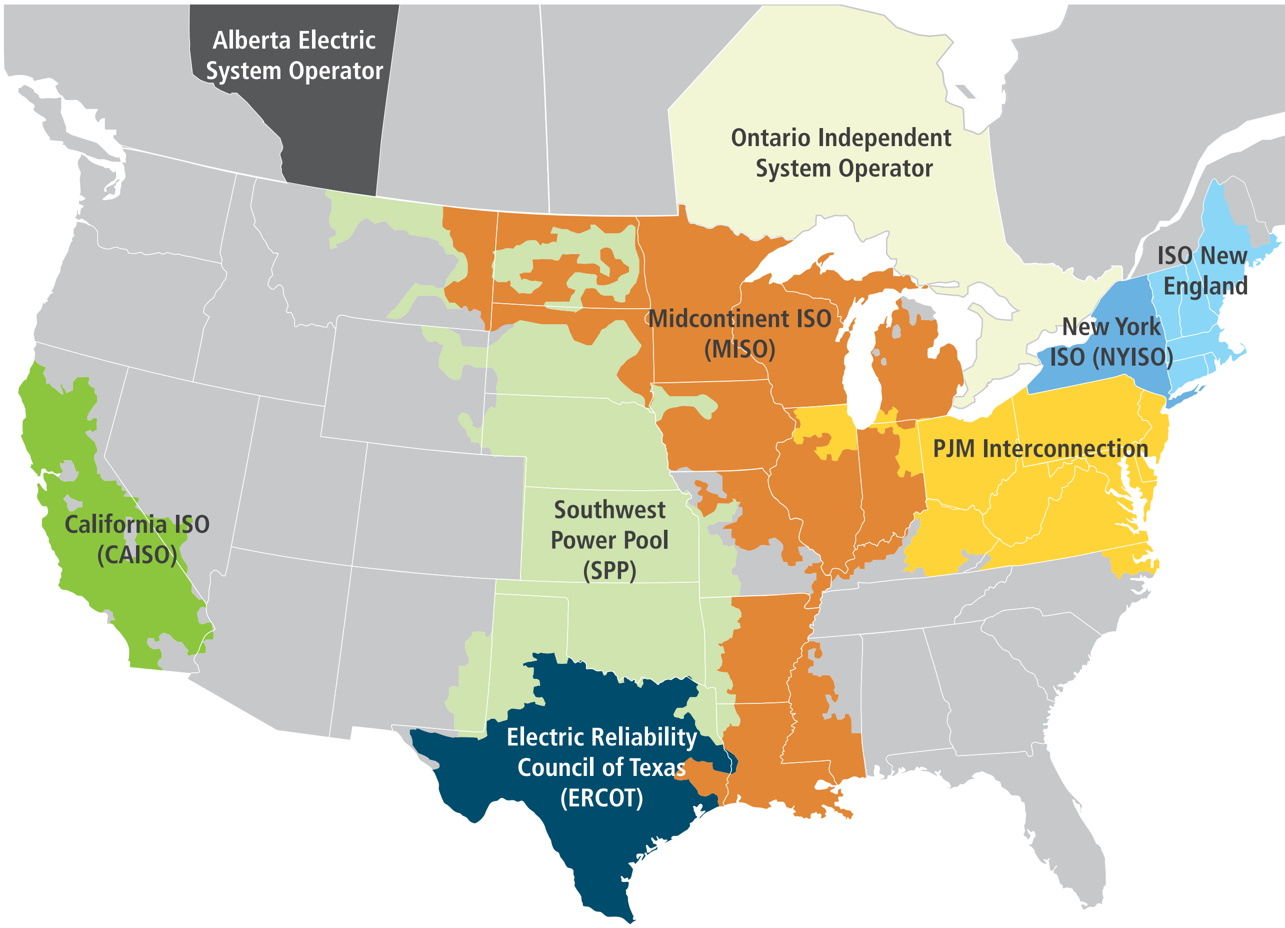
Different operating approaches are used throughout the country, though all focus on minimizing costs and maintaining reliability. In some areas, utilities operate their own systems based on their costs for resource options and operating decisions. Other regions operate based on organized markets, where market participants place supply and demand bids into a centralized market, and a market operator determines the least-cost mix of bids.[ap] Market participants then pay and earn money based on market prices for electricity and ancillary services. System operators in these areas are called ISOs or RTOs,[aq] and their markets—except for Electric Reliability Council of Texas (ERCOT), which covers most of Texas—are overseen by FERC.[ar]

[ap] The operations of markets are discussed in greater detail in the "Electric Power Markets" section of this appendix.

[aq] There are small distinctions between ISOs and RTOs, though they are insignificant for the level of discussion in the QER. Throughout, the terms will be used synonymously.

[ar] The jurisdiction and authority of FERC is discussed in greater detail in the "Federal Actors" section of this appendix.

Figure A-8. Regional Transmission Organizations, 2015[103]



FERC encouraged voluntary formation of ISOs and RTOs through a series of landmark orders that paved the way for open access to transmission and created large, centrally organized power markets in the United States. There are currently seven ISO/RTOs in the United States, and their geographic extent changes periodically.

aintaining operational reliability of the power system requires focusing on a set of essential reliability services, called ancillary services, provided by generation and load that aid in maintaining frequency and voltage of the system within acceptable bounds during normal operations and immediately after minor system disturbances.[as] Examples of these services include frequency response (automatic generator response to grid frequency deviations) and spinning reserves (generators that remain running and able to increase or decrease their output when instructed). Some ISO/RTO market regions procure ancillary services through markets that mirror their energy markets. Additional services are procured in these regions through cost-of-service payments. In non-ISO/RTO regions, many ancillary services are provided under a cost-of-service basis. The evolving composition of the electricity generation fleet has implications for long-term availability of these system-essential reliability services.[104]

[as] The term Essential Reliability Services is used by NERC to describe a set of necessary operating characteristics of resources on the bulk power system required to reliably operate the bulk power system in North America. For voltage support, it includes reactive power/power factor control, voltage control, and voltage disturbance performance. For frequency management, it includes inertia, frequency disturbance performance, operating reserves, and active power control (which includes frequency control and ramping capability). Ancillary services are a subset of Essential Reliability Services. Source: North American Electric Reliability Corporation (NERC), *Essential Reliability Services Task Force: A Concept Paper on Essential Reliability Services that Characterizes Bulk Power System Reliability* (Atlanta, GA: NERC, October 2014), http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSTF%20Concept%20Paper.pdf.

Reliability and the Role of the North American Electric Reliability Corporation (NERC)

Over the past 50 years, Federal oversight of the reliability of the bulk power system has increased. The 1965 Northeast power blackout precipitated the formation of NERC, but bulk power system reliability standards were voluntary and subject only to industry oversight.[at] A 2003 blackout that affected more than 50 million customers led to the inclusion in the Energy Policy Act of 2005 of requirements for mandatory bulk power reliability standards and enforcement, including designation of an electric reliability organization.[au] The Federal Energy Regulatory Commission oversees NERC in its development and enforcement of mandatory reliability standards for the bulk power system. States retain oversight of local reliability, which includes lower voltage transmission lines and distribution systems. NERC mandatory reliability standards address weaknesses in the prior voluntary system that were identified in the 2003 blackout investigation.

[at] North American Electric Reliability Corporation (NERC), *NERC Operating Manual* (Atlanta, GA: NERC, June 15, 2004), HIST-1, http://www.nerc.com/comm/oc/operating%20manual%20dl/opman_june_15_2004.pdf.

[au] David W. Hilt, *August 14, 2003, Northeast Blackout Impacts and Actions and the Energy Policy Act of 2005* (Princeton, NJ: North American Electric Reliability Corporation, August 14, 2003), 10–11, http://www.nerc.com/docs/docs/blackout/ISPE%20Annual%20Conf%20-%20August%2014%20Blackout%20EPA%20of%202005.pdf.

Business Models

Electricity in the United States is produced and delivered by a diverse set of actors using a range of business models. Depending on the operating model in question, these actors can be subject to regulation and oversight by different combinations of local, state, and Federal agencies. A key factor for differentiating between actors is ownership: companies can be investor-owned, publicly owned, or cooperatively owned. Within each of these three ownership models there are significant variations in purpose, regulatory oversight, prevalence, and size. Table A-4 provides overview statistics for the most common types of utility ownership. In addition to these primary ownership models, there are a number of businesses that provide distributed resources like DR aggregation and distributed solar. Table A-5 provides a taxonomy of utility business models by ownership and asset types.

Table A-4. Characteristics of Major Utility Types[105, 106]

Utility Type	Number of Utilities	Number of Customers	Miles of Power Lines	
			Transmission	Distribution
Investor-Owned Utilities	169	107,600,000	3,467,000	459,500
Municipal Utilities	1,834	15,150,000	321,000	27,590
Rural Electric Cooperative Utilities	814	19,230,000	2,400,000	116,600
Federal and Publicly-Owned Utilities	124	5,280,000	333,700	95,960
Total	**2,941**	**147,200,000**	**6,408,000**	**699,700**

Municipal utilities are the most numerous of the various utility types, though IOUs serve far more customers. Rural electric cooperatives have a higher proportion of distribution miles per customer served than investor-owned or municipal utilities.

IOUs are privately owned, for-profit utilities whose retail service is regulated by state PUCs that may be either vertically integrated or restructured to only own transmission and distribution. IOUs earn a regulated rate of return based on investments made to serve their ratepayers.

Rural electric cooperatives include nonprofit, member-owned distribution utilities and generation and transmission utilities. The cooperative business model is predicated on providing its customers with reliable, affordable energy that is locally owned and operated. The model is unique in that customers are "members" of the cooperative and, as such, hold ownership and voting stakes. Management is democratically elected by the membership, and the prevailing methodology is one meter, one vote.[107] Cooperatives receive a significant portion of their financing both directly and indirectly from the Federal Government, through both the Department of Agriculture's Rural Utility Service and cooperative banks like the National Rural Utilities Cooperative Finance Corporation. Electric cooperatives are not subject to Federal income tax, and thus must collaborate with a third party to monetize tax credits available for utility and generation investments.

Public power utilities are owned by a governmental entity, such as municipalities, states, public utility districts, or irrigation districts, and vary in size and scope from small distribution utilities to large, vertically integrated utilities. Public power also includes joint-action agencies that may own generation and transmission and provide power purchasing services for their member utilities, such as the Lower Colorado River Authority and Missouri River Energy Services. Joint action agencies allow small distribution-only public power utilities to aggregate their demand and contract for and/or build generation, transmission, and other common services.

Federally owned utilities operate in the generation and transmission segments of the power system in several parts of the country. Four Power Marketing Administrations market hydropower generation at dams operated by the Bureau of Reclamation or the Army Corps of Engineers. TVA has a portfolio of generation and transmission to sell wholesale electricity to public power and cooperatives in its footprint. Federal law grants preference for electricity marketed by Federal utilities to public power and cooperative utilities.[av] Federally owned generation resources produce approximately 7 percent of all power in the United States, and they own approximately 14 percent of all transmission lines.[108, 109]

Merchant/independent power producers (IPPs) sell power through markets and bilateral contracts with utilities and other customers. IPPs typically have market-based—rather than cost-based—rates and do not have captive customers. They may or may not be affiliated with an IOU through a holding company. In 2014, IPPs produced approximately 40 percent of the Nation's electricity.[110] IPPs are often subject to hard-to-predict market conditions and can experience volatile cash flows and returns.

Competitive retail energy suppliers are companies that sell power to end users in states with competitive retail markets. As such, they do not earn a regulated rate of return. Although distribution utilities are the only entities that can *deliver* power directly to retail customers, in certain states customers can choose the *suppliers* of that power. In practice, this "retail choice" means that a consumer can sign a contract with a qualified third-party electric service provider who could, in turn, contract with a generator (on a bilateral basis), self-generate, or purchase power in the wholesale market, and pay the necessary tariffs to the transmission owner and distribution utility.

Energy service companies (ESCOs) were traditionally providers of turnkey energy efficiency retrofits, but ESCOs are now offering biomass, geothermal, wind, and solar generation, bill management, energy monitoring, and energy procurement.[111] ESCOs explicitly guarantee energy savings for the consumer and charge a fee below that savings, known as an energy savings performance contract.[112]

Demand-response aggregators contract with large groups of end users to curtail their load if called upon to do so by the local utility or balancing authority. This flexibility is useful for reliability and economic reasons. There are many different providers of demand-response aggregation, including existing utilities and third-party providers.[113] The terms and conditions of third-party access to wholesale markets differ between ISOs and RTOs, but, generally,

[av] Preference clauses for Federal power sales originate from a series of congressional acts regarding Federal land reclamation and hydropower development, beginning with the Reclamation Act of 1906. See GAO-01-373 for further details.

aggregators can participate in both energy and capacity markets to provide energy and ancillary services (including synchronized reserves).[114] Of 9.3 million participants registered in DR in 2014, by count, over 90 percent are residential customers. However, over 75 percent of actual peak-demand savings came from commercial and industrial customers in 2014.[115]

Table A-5. Taxonomy (Ownership/Scope) of Utility Business Models with Representative Firms[116]

	State-Regulated IOU	Rural Electric Cooperative	Publicly Owned	Federally Owned	Merchant	Competitive Retail Energy Supplier*
Vertically Integrated**	Oklahoma Gas & Electric	–	Los Angeles Department of Water & Power	–	–	–
Transmission and Distribution	Pepco	Southern Maryland Electric Cooperative	Clallam County Public Utility District	–	–	–
Generation and Transmission	–	Basin Electric G&T	New York Power Authority	Tennessee Valley Authority	LS Power	–
Generation and Distribution	DTE Energy; Consumers Energy	Fox Island Electric	Lansing Board of Water & Light	–	NRG	–
Transmission Only	–	Upper Missouri Power Cooperative	Transmission Agency of Northern California	Western Area and Southwestern Power Administrations	ITC; Hudson Transmission; Transource Energy; Clean Lines Energy Partners	–
Distribution Only	Mt. Carmel Public Utility Co.	Kenergy	Nashville Electric Service	–	–	–
Generation Only	–	–	Wyoming Municipal Power Agency	Bureau of Reclamation	Calpine; BP Energy; Tenaska	–
Retail Sales Only***	–	–	–	–	–	Direct Energy; Veteran Energy

* Competitive retail energy suppliers are a special category of market participants that buy and sell electricity, but do not own any generation or infrastructure. Some ESCOs are retailers.

** Vertically integrated entities integrate generation, transmission, and distribution.

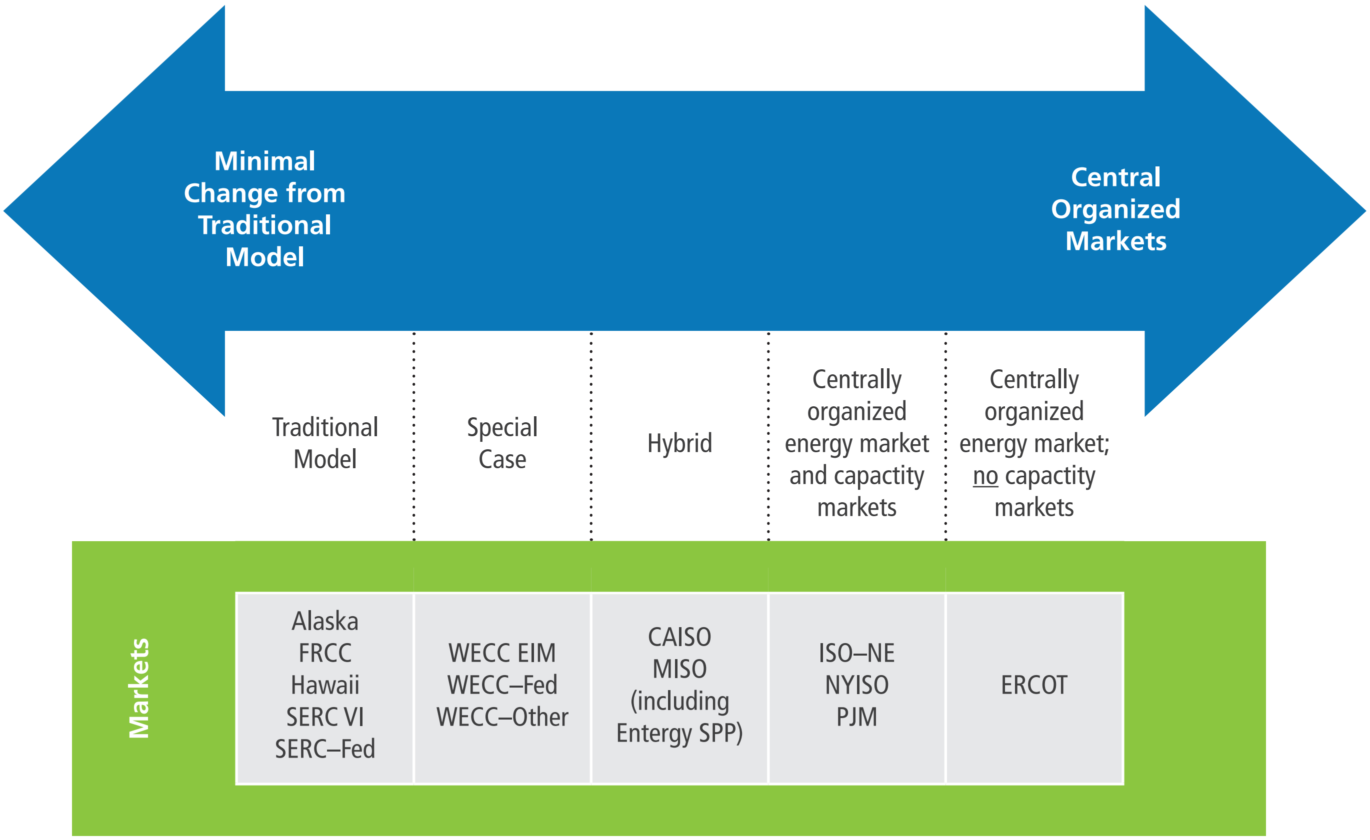
*** All business model categories in this table may include retail sales in addition to other services.

Utilities in the U.S. electricity sector have a variety of ownership and asset structures. They range from being fully vertically integrated to selling only one service, and they can be owned by government or public entities, cooperatives, or independent companies.

Electric Power Markets

Rather than consisting of a single overarching market, the U.S. electricity industry can instead be considered something of a patchwork, with different regional markets pursuing different mechanisms to provide electricity service to end users. The simplest characteristic differentiating these markets is whether resources are scheduled, dispatched, and compensated by a centrally organized RTO/ISO, or if they operate under the more traditional model wherein vertically integrated utilities operate within their franchise areas and receive revenues based on the cost of service. From this bifurcation, the organized markets can be further classified according to the types of resource adequacy constructs they use. These two attributes form a useful framework for analyzing the degrees to which the various markets differ from one another, and also underscore the diversity of approaches to electricity policy amongst the states.

Figure A-9. Spectrum of Electricity Markets[117]



This graphic illustrates the degree to which various U.S. regions have changed from the traditional market model. The two primary characteristics measured here are resource adequacy constructs and whether the market is centrally organized. Markets include: ERCOT, ISO New England (ISO-NE), New York ISO (NYISO), the PJM Interconnection (PJM), California ISO (CAISO), Midcontinent ISO (MISO), SERC Reliability Corporation (SERC), Southwest Power Pool (SPP), and the Energy Imbalance Market (EIM) in the Western Electricity Coordinating Council (WECC) region. The markets listed under "special case" and "traditional model" are classified by NERC region and are not standardized designations.

Regions Address Resource Adequacy with a Variety of Mechanisms

Resource adequacy is "the ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements."[aw] Planning for adequate investment in generation and transmission capacity to ensure resource adequacy is a critical component of ensuring a reliable electricity system.

Traditional, vertically integrated regions and some utilities in hybrid markets conduct an integrated resource planning process to plan for necessary capacity investments. Some centrally organized markets have implemented capacity markets as a mechanism for ensuring future resource adequacy. In these markets, the system operator conducts an auction process, and retail service providers procure resources to meet the electricity demands of their customers. These markets can be mandatory (PJM Interconnection and Independent System Operator [ISO]–New England); voluntary, where utilities can choose to operate under an integrated resource planning process (Midcontinent ISO); or voluntary backstopped by a mandatory process (New York ISO).[ax] Other regions (California ISO and the Southwest Power Pool) have capacity obligations where market operators require utilities to procure necessary generation reserves, either through ownership or through contracts with third-party providers. Another market-based approach, used in the Electric Reliability Council of Texas, relies on energy prices alone and does not have formal requirements or markets for capacity. In this approach, market scarcity pricing, or relatively high energy prices during high-demand periods reflecting the lack of ample additional resources, provides necessary financial incentives for investment in generation capacity.

[aw] North American Electric Reliability Corporation, "Glossary of Terms Used in NERC Reliability Standards," last modified November 28, 2016, http://www.nerc.com/pa/stand/glossary%20of%20terms/glossary_of_terms.pdf.

[ax] K. Spees, S. Newell, and J. Pfeifenberger, "Capacity Markets—Lessons Learned from the First Decade," *Economics of Energy & Environmental Policy* 2, no. 2 (2013): 10, doi:10.5547/2160-5890.2.2.1.

"Traditional" markets (the Southeast of the United States, for example) are dominated by vertically integrated IOUs that operate under a regulated cost-of-service model, serving customers in a defined franchise area. Public power and rural cooperative utilities also have a significant presence in some regions, and their utility asset ownership models can vary from vertically integrated to distribution-only. IPPs can also operate within these regions to some degree. However, the majority of power is produced and delivered by the integrated utilities.

Power purchases between these various entities are generally limited to bilateral trades. These can be made to take advantage of price discrepancies or cover shortfalls in supply. These bilateral transactions represent a small portion of the total generation in traditional markets and are typically in the form of long-term power purchase agreements instead of short-term trades. For example, in 2015 FERC estimated that short-term trades, called spot transactions, in the Southeast region accounted for less than 1 percent of overall supply.[118]

Centrally organized markets (ERCOT and New York ISO, for example) are markets where utilities were required to sell their power generation assets and keep only the "wires" component of the business. Generation assets were sold to IPPs who now operate these assets and build new generation based on expected market earnings. These assets work in a competitive fashion, with the IPP owners either (1) looking to sell power under bilateral contracts to utilities or other off-takers, such as industrial users, or (2) dispatching their power into wholesale energy markets.

In wholesale "energy-only" markets, units bid in on a day-ahead basis what price they are willing to produce power at, based on an assessment of their operating costs, fuel costs, and return expectations. The system operator (RTO/ISO) then pools these bids in a centralized fashion and determines a clearing price that matches supply, demand, and congestion forecasts for a given period. Notably, all units receive that marginal clearing price for that period, even if their bid prices are significantly lower than the clearing price determined by the ISO. In addition, the typical markets maintain price caps that limit what can be charged in any particular hour in order to limit the potential for market manipulation.

"Hybrid" centrally organized markets (for example, California ISO and the Southwest Power Pool) combine elements of centrally organized energy markets and traditional resource adequacy mechanisms. In fact, several of these markets had moved toward more of a pure restructured model before moving back to elements of the more traditional regulated approach.

Transmission Access, Competition, and Planning

While Congress has found that generation can be provided through competitive mechanisms and therefore encouraged restructuring in that segment of the industry in the 1990s, increasing competition among transmission owners and reducing barriers to using transmission have been more incremental processes.

Originally, incumbent transmission owners largely controlled third-party access to transmission lines, effectively precluding competition at the wholesale level. Buyers and sellers of wholesale power that did not own the transmission connecting them had difficulty reaching each other over another's transmission lines at reasonable cost. EPAct 1992 resolves this issue by providing FERC with greater authority to provide transmission access for wholesale buyers in procuring wholesale electric supplies. Since 1992, FERC has taken multiple actions to increase operational and economic efficiency and equity of transmission operations and pricing.

FERC adopted Order No. 888 and Order No. 889, which require electricity utilities that own transmission lines used in interstate commerce to offer transmission service on a nondiscriminatory basis to all eligible customers, including non-jurisdictional entities such as public power, rural cooperatives, and Federal utilities. Order No. 2000 further encouraged utilities to join RTOs to improve the efficiency and equity of the transmission systems. FERC Order No. 890 built upon Order No. 888 to encourage more transparent planning and use of the transmission system and to reduce opportunities for undue discrimination.

FERC Order No. 1000 covers concepts such as (1) precluding, in most circumstances, incumbent transmission owners from having Federal rights of first refusal to build transmission within their service territories, (2) the opportunity for entities not previously recognized as transmission owners in the region (non-incumbents) to compete to develop transmission facilities and allocate the costs of those facilities, and (3) the requirement that project costs be allocated in a manner that is at least roughly commensurate with expected benefits from the projects.

Transmission owners, operators, and regional coordinators implement structured transmission planning processes to identify solutions that can more efficiently or cost-effectively maintain system reliability and accommodate changes in generation capacity and demand. Meeting the transmission planning goal requires both technical (engineering) analysis of different power systems configurations and economic analysis of projects proposed to meet the identified needs. In the United States, the transmission planning process generally falls into three geographic categories: local, regional, and interregional coordination.

Local transmission planning activities are carried out by incumbent transmission owners. These transmission owners assess their system and implement local solutions within their own service territory. Regional transmission planning includes assessment of solutions within a given planning region that spans several transmission owner service territories. Regional transmission planning relies on extensive stakeholder engagement, power system simulation modeling, and long-term economic impact analysis of alternative transmission projects. Interregional coordination is implemented for solutions that involve more than one ISO/RTO or planning entity. Interregional coordination activities are mostly guided by the principles outlined in FERC Order No. 1000.

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LIST OF ACRONYMS AND UNITS

AC	alternating current
AMI	advanced metering infrastructure
AML Fund	Abandoned Mine Lands Reclamation Fund
ARC	Appalachian Regional Commission
ARRA	American Recovery and Reinvestment Act of 2009
Btu	British thermal unit
CCUS	carbon capture, utilization, and storage
CES	Clean Energy Standard
CHP	combined heat and power
DC	direct current
DER	distributed energy resources
DG	distributed generation
DOE	Department of Energy
DR	demand response
EE	energy efficiency
EERS	Energy Efficiency Resource Standard
ERCOT	Electric Reliability Council of Texas
ESCO	energy service company
EV	electric vehicle
FAST Act	Fixing America's Surface Transportation Act
FERC	Federal Energy Regulatory Commission
GDP	gross domestic product
GHG	greenhouse gas
GW	gigawatt
HVAC	heating, ventilation, and air conditioning
ICT	information and communications technology
IEEE	Institute of Electronics and Electrical Engineers
IoT	Internet of Things
IOU	investor-owned utility

IPP	independent power producer
ISO	independent system operator
ITC	Investment Tax Credit
kWh	kilowatt-hour
LED	light-emitting diode
LEED	Leadership in Energy and Environmental Design
LIHEAP	Low Income Home Energy Assistance Program
MEL	miscellaneous electrical load
MISO	Midcontinent Independent System Operator
MW	megawatt
MWh	megawatt-hours
NEMS	National Energy Modeling System
NERC	North American Electric Reliability Corporation
NGCC	natural gas combined cycle
PMU	phasor measurement units
PPA	power purchase agreement
PTC	Production Tax Credit
PUC	public utility commission
PURPA	Public Utilities Regulatory Policies Act
PV	photovoltaic
QER	Quadrennial Energy Review
Quads	Quadrillion British thermal units
RD&D	research, development, and deployment (RDD&D = research, development, demonstration, and deployment)
RPS	renewable portfolio standard
RTO	regional transmission organization
SCADA	supervisory control and data acquisition
T&D	transmission and distribution
TOU	time of use
TWh	terawatt-hour
VER	variable energy resource

TERMS OF REFERENCE

Term of Reference	Definition
Advanced metering infrastructure (AMI)	An integrated system of smart meters, communications networks, and data-management systems that enables two-way communication between utilities and customers. Customer systems include in-home displays, home area networks, energy-management systems, and other customer-side-of-the-meter equipment that enable smart grid functions in residential, commercial, and industrial facilities.[1]
Aggregator	"Any marketer, broker, public agency, city, county, or special district that combines the loads of multiple end-use customers in negotiating the purchase of electricity, the transmission of electricity, and other related services for these customers."[2] For example, demand response aggregators contract with consumers to individually provide demand response and then take the aggregated demand response provided by the contracts and bid it in regional transmission organizations'/independent system operators' wholesale markets or deliver it to contracted utilities.
Avoided costs	The cost a supplier would have incurred by providing an incremental unit of service but avoids by not doing so. Short-run avoided cost is the incremental variable cost to produce another unit from existing facilities. Long-run avoided cost includes the cost of the next power plant a utility would have to build to meet growing demand, plus the costs of augmenting reliability reserves, additional transmission and distribution facilities, environmental costs, and line losses associated with delivering that power.
Balancing area	The collection of generation and transmission resources and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area.
Balancing Authority	The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a balancing area, and supports interconnection frequency in real time.
Botnet	An interconnected network of computers infected with malware without the users' knowledge, used by cybercriminals to send spam, propagate viruses, coordinate distributed denial-of-service attacks, and other malicious or criminal acts.[3]
Bulk power system	Facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof), and electric energy from generation facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy.[4]
Business as usual (BAU)	An analysis case that assumes current laws and regulations are largely unchanged throughout the projection period, and that technology cost and performance and consumer adoption patterns continue to follow recent trends.
Capacity	A measurement of the maximum output that generating equipment can supply to a system load, commonly expressed in megawatts. Differs from the term "generation," which measures the actual electricity produced, allowing for equipment down time.
Capacity factor	The ratio of actual generation divided by maximum output (generation/capacity).
Centrally organized electricity markets	Markets in which utilities own only the "wires" component of the business. Generation assets are owned by third-party generators, or independent power producers (IPPs), who operate these assets and build new generation based on expected market earnings. These assets work in a competitive fashion, with the IPP owners either (1) looking to sell power under bilateral contracts to utilities or other off-takers, such as industrial users, or (2) dispatching their power into wholesale energy markets.

Term of Reference	Definition
Clean electricity system	A system that is developed and managed to minimize environmental impacts at all stages of power generation, transmission, and distribution. A clean electricity system utilizes technologies and processes to limit water and air pollution, reduce net greenhouse gas emissions, address waste treatment and disposal challenges, and reduce other water and land-use impacts.
Combined heat and power (CHP) plant (related to cogeneration)	"A plant designed to produce both heat and electricity from a single heat source. Note: This term is being used in place of the term "cogenerator," which was used by EIA in the past. CHP better describes the facilities because some of the plants included do not produce heat and power in a sequential fashion and, as a result, do not meet the legal definition of cogeneration specified in the Public Utility Regulatory Policies Act."[5]
Cooperative electric utility (co-op)	An electric utility legally established to be owned by and operated for the benefit of those using its service. The co-op may generate, transmit, and/or distribute supplies of electric energy to a specified area not being served by another utility. Co-ops are generally exempt from Federal income tax laws. Most were initially financed by the Rural Utilities Service (prior Rural Electrification Administration), within the Department of Agriculture.[6]
Cost of service	"A ratemaking concept used for the design and development of rate schedules to ensure that the filed rate schedules recover only the cost of providing the electric service at issue. This concept attempts to correlate the utility's costs and revenue with the service provided to each of the various customer classes."[7]
Critical infrastructure	Systems and assets, whether physical or virtual, that are so vital to the United States that the incapacity or destruction of such systems and assets would have a debilitating impact on national defense, national economic security, national public health or safety, or any combination thereof.
Demand response (DR)	A voluntary program offered by independent system operators/regional transmission organizations, local utility service providers, or third parties, which compensate end-use (retail) customers for reducing and/or changing the pattern of their electricity use (load) over a defined period of time, when requested or automatically instructed to do so during periods of high power prices or when the reliability of the grid is threatened.
Demand-side management (DSM)	Efforts by electric utilities and other entities to modify the level or pattern of consumer energy use. DSM includes energy efficiency improvements and demand response programs.
Deregulation	The "substitution of market prices for government regulation of the energy portion of utility rates."[8] This includes the unbundling of vertically integrated utilities into separate entities for generation, transmission, and/or distribution, as well as the introduction of market-based competition.
Distributed energy resources (DER)	A wide range of generating and/or load-reducing technologies and programs that reside on a utility's distribution system or on the premises of an end-use consumer, including distributed generation, distributed storage, and demand-side management resources (including energy efficiency). In QER 1.2, DER include demand response and some enabling technologies, such as "smart" devices with controllable loads, which enable grid operators or consumers to better manage individual and system demand. Not all DER are connected to a utility electric grid or can be controlled by grid operators (e.g., resources deployed on microgrids and some CHP systems).[a] Some DER, such as distributed solar photovoltaics and energy-efficient equipment, can have a significant impact on system load, but may not be under the direct control of grid operators. Other technologies, such as residential hot water heaters, have the potential to serve as DER as a demand response measure, but technologies enabling this resource are still nascent.

[a] Note that the Energy Information Administration considers DER that are not connected to the grid as "dispersed generation" rather than "distributed generation." See https://www.eia.gov/forecasts/aeo/nems/2013/buildings/.

Term of Reference	Definition
Distributed generation (DG)	The subset of DER technologies that produce electricity at or near the point of consumption, such as rooftop solar photovoltaics and distributed wind resources. QER 1.2 defines industrial CHP facilities as DG, whether or not they are selling power back to the grid, but does not consider central power plants that employ CHP technologies as DG. Backup generators also constitute a DG resource, although data availability on their usage is limited and they behave differently from other DG technologies given their primary role as an emergency-use resource.
Distribution network	The portion of the electricity system that delivers power received from the transmission network and/or directly received from DG sources to end users.
Dynamic pricing	A rate structure in which utilities set variable prices for electricity service based on wholesale market prices (real-time pricing) or an approved rate schedule (time-of-use pricing) tailored to specific customer categories and based on demand patterns.
Economic dispatch	The operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities, and the dispatch of this energy in increasing order of cost.
Electricity system or grid	The system that connects electricity producers and consumers by transmission and distribution lines and related facilities.[9]
Electromagnetic pulse (EMP)	"A blast of electromagnetic energy that can disrupt—if not destroy—electronic devices within an affected area. Manmade EMPs are produced by nuclear weapons or other devices designed to create intentional electromagnetic interference. The impact of an EMP from a high-altitude nuclear explosion or even a smaller nuclear device affects more than just the electric sector. Other critical infrastructures that use microprocessors are also vulnerable."[10]
Energy assurance plans	Formalized plans designed to achieve secure, reliable, and resilient energy systems, often undertaken at the state and local government levels.
Energy service company (ESCO)	Companies that develop, design, build, and fund projects that save energy, reduce energy costs, and decrease operations and maintenance costs at their customers' facilities.[11]
EPSA Base Case	A modeled scenario of what the future U.S. energy sector might look like (out to 2040), given a reference set of assumptions and methodologies. It is based on the 2015 *Annual Energy Outlook* High Oil and Gas Resource Case, with updated cost and performance estimates for a number of electricity generating technologies. The EPSA Base Case incorporates all existing U.S. policies—the most recent of which were the Clean Power Plan and the December 2015 extension of the Federal renewable Production and Investment Tax Credits—but assumes no new policies or technology breakthroughs. It is important to note that this analysis is not a *prediction* of the future energy system, but rather an assessment of how a set of reference assumptions about energy supply and technology cost and performance metrics impact future energy demand and carbon dioxide emissions.
Essential reliability services (ERS, also referred to as ancillary services)	"The elemental 'reliability building blocks' from resources (generation and demand) necessary to maintain bulk power system reliability. ERS are operational attributes from conventional generation, such as providing reactive power to maintain system voltages and physical inertia to maintain system frequency, necessary to reliably operate the bulk power system."[12]
Flexibility	The ability of a resource—whether it is a component or a collection of components of the power system—to respond to the scheduled or unscheduled changes of power system conditions at various operational timescales.
Geomagnetic storm	A temporary disturbance of the Earth's magnetic field resulting from solar activity.[13]
Independent power producer (IPP), or merchant power producer	"A corporation, person, agency, authority, or other legal entity or instrumentality that owns or operates facilities for the generation of electricity for use primarily by the public, and that is not an electric utility"[14] and may operate under a longer-term contract (power purchase agreement) with a utility buyer or as an entity that operates without longer-term contracts, bidding into wholesale markets.

Term of Reference	Definition
Independent system operator (ISO)/ regional transmission operator (RTO)	An independent, Federally regulated entity established to coordinate regional transmission in a non-discriminatory manner and ensure the safety and reliability of the electric system.[15]
Inertia	An essential reliability service in which sudden frequency changes on the grid are dampened by the ability of spinning synchronous generators to absorb kinetic energy from or add kinetic energy to the grid. This ability results from the physical property of rotational inertia, or the tendency of a spinning object to keep spinning absent the application of torque. Large rotating loads, such as industrial motors, can also contribute to system inertia.[16, 17]
Information and communications technology	Computing and telecommunication technologies used for data storage, retrieval, processing, and transmission.
Integrated Resource Planning	The process of developing "a utility plan for meeting forecasted annual peak and energy demand, plus some established reserve margin, through a combination of supply-side and demand-side resources over a specified future period."[18]
Internet of Things (IoT)	"Sensors and actuators embedded in physical objects—from roadways to pacemakers—[that] are linked through wired and wireless networks, often using the same Internet Protocol (IP) that connects the Internet."[19]
Investor-owned utility (IOU)	"A privately owned electric utility whose stock is publicly traded. It is rate-regulated and authorized to achieve an allowed rate of return."[20]
Islanded Communities	Communities that are disconnected from mainland transmission grids due to their location on physical islands or in remote locations with local grids, such as Alaska.[21]
Levelized cost of electricity (LCOE)	The per-kilowatt-hour cost of building and operating a generating plant over an assumed financial life and duty cycle. Key inputs to calculating LCOE include capital costs, fuel costs, fixed and variable operations and maintenance costs, financing costs, and an assumed utilization rate for each plant type.[22]
Microgrid	A discrete energy system consisting of distributed energy sources (including demand management, storage, and generation) and loads capable of operating in parallel with, or independently from, the main power grid.[23]
Miscellaneous electrical load (MEL)	Electric loads not linked to a building's core functions of lighting, space heating and cooling, refrigeration, and water heating. They include a broad range of products across all sectors, including televisions, pool heaters and pumps, security systems, and ceiling fans.[24]
National Energy Modeling System (NEMS)	An integrated energy system model that is maintained by the Energy Information Administration (EIA). According to the EIA, "NEMS projects the production, imports, conversion, consumption, and prices of energy, subject to assumptions on macroeconomic and financial factors, world energy markets, resource availability and costs, behavioral and technological choice criteria, cost and performance characteristics of energy technologies, and demographics."[25]
Nationally determined contributions (NDCs)	Submissions to the United Nations Framework Convention on Climate Change from all signatories of the Paris Agreement (as contained in the report of the Conference of the Parties on its 21st session) that outline a country's target level of greenhouse gas emissions reductions and the domestic mitigation measures that the country will pursue to achieve that target. NDCs must reflect each country's highest possible ambition, and they must be submitted every 5 years, with each new submission establishing a stronger target.
Power purchase agreement (PPA)	A contract between an electricity generator (the seller) and an electricity purchaser to buy electricity from a particular generation resource over a set period of time. Most PPAs are between power producers and utilities and tend to be up to 20 years in duration.
Public utility commission (PUC)	"The state regulatory body that determines rates for regulated utilities. Although they go by various titles, PUC and Public Service Commission are most common."[26]
Ramping and steep ramping	The process of increasing the output of a power plant; steep ramping of a conventional power plant's output is often required when the output of variable energy resources (e.g., wind and solar) drops sharply.

Term of Reference	Definition
Rate of return	The gain or loss on an investment over a specified time period, expressed as a percentage of the investment's cost. Gains on investments are defined as income received plus any capital gains realized on the sale of the investment.[27]
Reliability	"The ability of the power system to deliver electricity in the quantity and with the quality demanded by users."[28]
Renewable portfolio standard (RPS)	A tool commonly used by states that typically requires utilities or other electricity providers to meet a minimum portion of load with qualifying forms of renewable energy. RPS rules vary from state to state, each having different targets, time frames, and, sometimes, specific carve-outs for solar or distributed generation.
Resilience	The electricity system's ability to adapt to changing conditions and prepare for, withstand, and rapidly recover from disruption.
Resource adequacy	The ability to provide adequate supply during peak load and generation outage conditions, which includes both supply-side and demand-side resources as contributors to meeting aggregate electrical demand (including losses)[29] while accounting for "scheduled and reasonably expected unscheduled outages of system elements."[30]
Retail choice	The ability to select a retail electricity supplier based on the rates, terms, and conditions of service offered.
Smart grid	An intelligent electricity grid—one that uses digital communications technology, information systems, and automation to detect and react to local changes in usage, improve system operating efficiency, and in turn reduce operating costs while maintaining high system reliability.
Spinning reserve	Reserve generating capacity running at a zero load and synchronized to the electric system.[31]
Time-of-use (TOU) rates	Electricity customer prices set in advance but varying over the day. Utilities can use time-of-use rate structures to shift electricity use from peak-load hours by offering lower rates during partial-peak and off-peak hours as a way to reduce strain on the electric grid.[32]
Unit commitment (UC) and dispatch	Setting the schedule of generating units within a power system subject to device and operating constraints, where the decision process selects units to be on or off, the type of fuel, the power generation for each unit, the fuel mixture when applicable, and the reserve capacity margin for each unit.
Variable energy resource (VER)	"A device for the production of electricity characterized by an energy source that is (1) renewable; (2) cannot be stored by the facility owner or operator; and (3) has variability that is beyond the control of the facility owner or operator. This includes, for example, wind, solar thermal and photovoltaic, and hydrokinetic generating facilities."[33]
Wholesale electricity capacity markets	A market offered by some, but not all, independent system operators/regional transmission organizations that ensures long-term grid reliability by procuring the appropriate amount of power supply resources needed to meet predicted energy demand in future years.

Endnotes

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