Appendix C

ELECTRICITY

Highlights

Investments in transmission and distribution upgrades and expansions will grow. It is anticipated that in the next two decades, large transmission and distribution investments will replace aging infrastructure; maintain reliability; enable market efficiencies; and aid in meeting policy objectives, such as greenhouse gas reduction and state renewable energy goals.

Both long-distance transmission and distributed energy resources can enable lower-carbon electricity. The transmission network can enable connection to high-quality renewables and other lower-carbon resources far from load centers; distributed energy resources can provide local low-carbon power and efficiency.

The potential range of new transmission construction is within historic investment magnitudes. Under nearly all scenarios analyzed for the Quadrennial Energy Review, circuit-miles of transmission added through 2030 are roughly equal to those needed under the base case. And while those base case transmission needs are significant, they do not appear to exceed historical yearly build rates.

Flexible grid system operations and demand response can enable renewables and reduce the need for new bulk-power-level infrastructure. End-use efficiency, demand response, storage, and distributed generation can reduce the expected costs of new transmission investment.

Investments in resilience have multiple benefits. Investments in energy efficiency, smart grid technologies, storage, and distributed generation can contribute to enhanced resiliency and reduced pollution, as well as provide operational flexibility for grid operators.

Innovative technologies have significant value for the electricity system. New technologies and data applications are enabling new services and customer choices. These hold the promise of improving consumer experience, promoting innovation, and increasing revenues beyond the sale of electric kilowatt-hours.

Enhancing the communication to customer devices that control demand or generate power will improve the efficiency and reliability of the electric grid. For example, open interoperability standards for customer devices and modified standards for inverters will improve the operation of the grid.

Appropriate valuation of new services and technologies and energy efficiency can provide options for the utility business model. Accurate characterization and valuation of services provided to the grid by new technologies can contribute to clearer price signals to consumers and infrastructure owners, ensuring affordability, sustainability, and reliability in a rapidly evolving electricity system.

Consistent measurement and evaluation of energy efficiency is essential for enhancing resilience and avoiding new transmission and distribution infrastructure. Efficiency programs have achieved significant energy savings, but using standard evaluation, measurement, and verification standards, like those recommended by the Department of Energy 's Uniform Methods Project, is key to ensuring that all the benefits of efficiency are realized, including avoiding the expense of building new infrastructure.

States are test beds for the evolution of the grid of the future. Innovative policies at the state level that reflect differences in resource mix and priorities can inform Federal approaches.

Different business models and utility structures rule out "One-Size-Fits-All" solutions to challenges. A range of entities finance, plan, and operate the grid. Policies to provide consumers with affordable and reliable electricity must take into account the variety of business models for investing, owning, and operating grid infrastructure.

Growing jurisdictional overlap impedes development of the grid of the future. Federal and state jurisdiction over electric services are increasingly interacting and overlapping.

Introduction

The United States has one of the world's most reliable, affordable, and increasingly clean electric systems—a system that powers its economy and provides for the well-being of its citizens. The U.S. electric system is at a strategic inflection point—a time of significant change for a system that has had relatively stable rules of the road for nearly a century.

Much change, including innovation, is underway in the transmission, storage, and distribution (TS&D) part of the electric power system, as discussed in this appendix and also summarized in industry documents.[1] Industry and state electricity officials are engaged in discussions of the many aspects of the changes and innovations occurring now, as well as those yet to occur.[a] Integrating all of the new technologies, products, and services into the grid is underway by many, with more work to be done on deployment—as the products, services, and technologies evolve and become commercial—but also on how all of the new pieces can fit together into the existing TS&D grid to become the *grid of the futur*e.

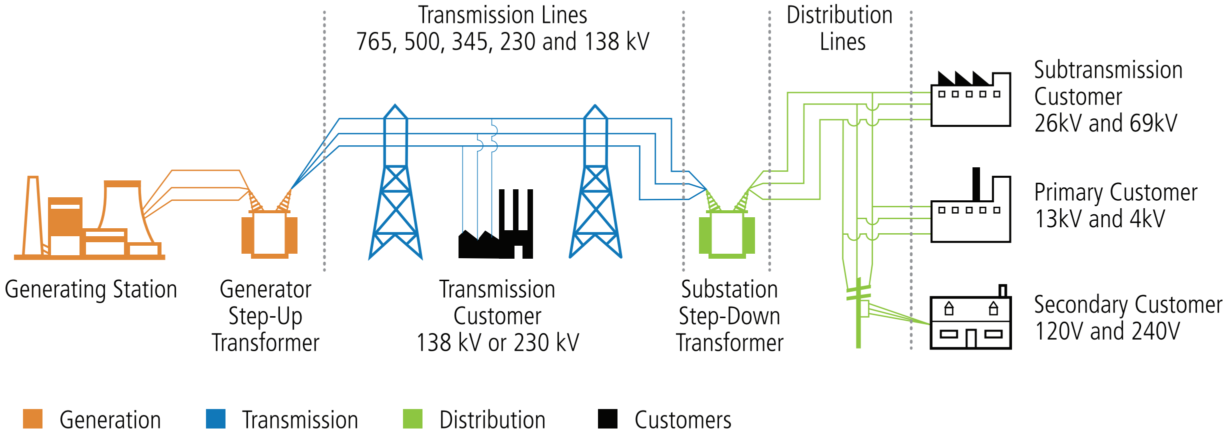
Ongoing and future policy and investment decisions and technology innovations will shape the electric system's future, including its ability to provide affordable and reliable service while withstanding a host of human-made and natural threats, and, at the same time, reduce energy-related greenhouse gas (GHG) emissions. The nature of the business model of providing various elements of electric service is evolving; yet, the grid must continue to provide essential services without interruption while accommodating change. Because the inflection point is really multiple inflection points in regulation, technology, and markets—occurring at different speeds in different parts of the country, and with a not-yet-clear end point—a clear picture of ongoing trends and new dynamics in the electricity sector is essential to plan for the future.

At the core of the electricity system is the grid—a complex, highly engineered network that coordinates the production and delivery of power to customers. There are six elements that make up the grid—four physical components of the electric system (generation, transmission, distribution, and storage); the information infrastructure to monitor and coordinate the production and delivery of power and operate the grid; and demand—the driver of power system operation and investment.

Figure C-1 shows three of the grid elements: generation, transmission, and distribution. Not shown are the current, relatively small amounts of storage, mostly on the bulk power part of the diagram. The diagram shows the traditional one-direction flow of electricity from central generation to the end user. Not depicted, but discussed later in this appendix, is the growing engagement of the customer emerging in some parts of the United States through use of distribution generation, energy efficiency, and other forms of customer engagement. These trends, if they continue, can have major implications for the electricity transmission and distribution (T&D) parts of the U.S. electric grid, one of which is increasingly two-way flows of electricity at the distribution level that is now designed for one-way flows.

[a] For example, at the February 16, 2015, meeting of the National Association of Regulatory Utility Commissioners in Washington, D.C., a session on "The Evolving [Distribution] Grid" had moderator Lisa Wood of the Institute of Electric Innovation state: "The conversation has moved forward from just a year ago — now we are discussing how the distribution grid is evolving into a broad platform to connect an increasingly diverse set of both supply-and demand-side resources. We are now squarely focused on the evolving distribution grid."

Figure C-1. The Electric Grid[2]



The current U.S. grid is the conduit for bulk generation to various end users. There are six elements that make up the grid: four physical components of the electric system (generation, transmission, distribution, and storage); the information infrastructure to monitor and coordinate the production and delivery of power and operate the grid; and demand—the driver of power system operation and investment. New storage technologies can be deployed throughout the power system in the future.

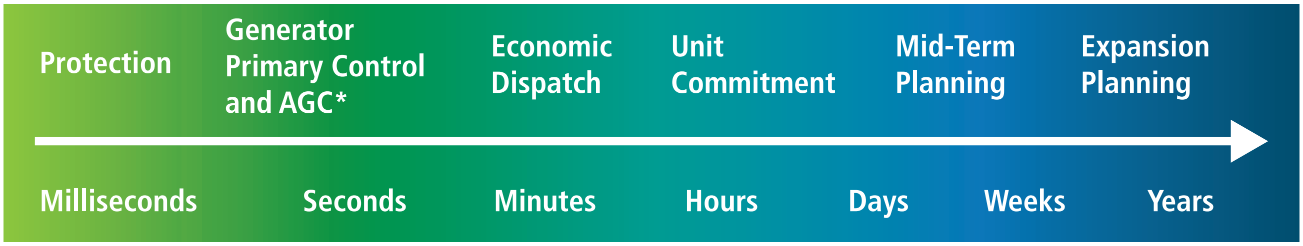
To serve a 21st century consumer base, the grid must and is adapting to emerging challenges and opportunities. Current drivers of change within the electricity sector include the growing use of natural gas to power electricity generation; low load growth; distributed generation; increasing deployment of renewable energy and the retirement of coal and nuclear generation; severe weather and climate change; and growing interactions at the Federal, state, and local levels. Internal drivers of change derive largely from the development and deployment of intelligent and advanced technologies that are increasing the ability to optimize the use of all grid and grid-connected resources, thereby improving grid productivity to control power flows, remotely troubleshoot problems, enable storage of electricity, and empower customers to better manage their energy use.

The future grid likely will accommodate and rely on an increasingly wide mix of resources, including large centralized and more dispersed, customer-side distributed generation—some of it intermittent and variable in nature. The prospect of new storage technologies also has the potential to alter the traditional requirements for generation adequacy, which is the amount of generation (and demand-side resources) required to maintain system reliability. Storage also has the potential to alter the nature of production, transmission, and distribution of power.

Change will occur at different rates in different parts of the country, largely determined by market and regulatory structures, along with the varying mix of current and future resources supplying customers in different regions.

This complex mix of new economic realities; changing resource mix; and the U.S. electrical system's physical architecture, institutional structure, and regulatory influences poses challenges to the planning and operations models that have driven electricity generation, transmission, and distribution decisions for the better part of a century. Coordinated planning and operation that has been essential to management of the grid will remain critical to ensuring its smooth function. However, the processes will need to account for millions of new customer-side generation and efficiency sources that are increasingly material to the TS&D system. This shift will have important region-specific characteristics, but in all cases, substantial planning, and often investment, will be necessary to meet grid operational needs on the scale of milliseconds, minutes, hours, years, and decades into the future (see Figure C-2 for a timescale of some of the continuous actions that must occur from milliseconds to years that are required to keep the Nation supplied with electricity reliably).

Figure C-2. Transmission Operation and Planning Functions Shown by Timescale[3]



* AGC = Automatic Generation Control

Reliable and affordable electricity requires a continuum of operating, planning, and investment decisions over a wide time horizon from real time to future years.

Evolution of the Electric Utility Industry and Its Regulation

The electric utility industry first sought regulation in exchange for the ability to provide service as a monopoly in Samuel Insull's 1898 presidential speech to the National Electric Light Association. Accordingly, state governments allowed private electric companies to exist as state-regulated monopolies, with the obligation to provide safe and adequate service at just and reasonable rates—a mandate that has been clarified over the last century through judicial decisions and legislative action. Investor-owned utility expansion and access to capital was accomplished through a financial structure called holding companies in which services were provided to the local utilities by these holding companies (which often covered many states). However, state regulatory agencies often lacked the jurisdiction or capacity to adequately regulate the rates and terms of holding company transactions. In response, Congress passed the Federal Power Act, which granted the existing Federal Power Commission jurisdiction over wholesale electric rates, such as those charged by holding companies to their subsidiaries. This grant of authority to the Federal Power Commission helped align regulatory functions with the physical structure of the electric system. The ongoing changes in the electric system are increasingly raising questions about the alignment between physical structure and regulation.

In addition to private electric companies, sometimes called investor-owned utilities, there exist publicly owned (often municipalities) and cooperatively owned utilities that also directly serve electricity customers through their distribution function. Each type of utility is subject to different regulatory requirements, and their diverse nature further adds to the complexity of addressing many of today's electricity issues. These differences are discussed later in this appendix.

At its beginning, the electric power industry was largely local and relatively limited in scale—with generation, transmission, and distribution built and owned by a single entity to serve a relatively small, geographically constrained set of customers. As diverse loads were added and generation technology demonstrated economies of scale, the cost of electricity was minimized by consolidating entities, first into larger utilities and ultimately interconnected power systems—with natural monopoly characteristics—producing service at the lowest cost to all. One element of this cost savings came from coordinating the operation of power plants based on the concept of economic dispatch, wherein generation resources were deployed on the basis of operating costs (subject to reliability requirements). Over time, the bulk power system was interconnected with longer-distance transmission lines, in some cases even among distant regions. Thus, for example, 500-kilovolt (kV), high-voltage, direct current transmission lines were built between the Pacific Northwest and California in the late 1960s to allow seasonal-based exchanges of electricity between the two regions when electricity generation was less expensive in one region than the other.[4]

Today, the U.S. T&D system is a vast physical complex of interlocked machines and wires, with a correspondingly complex set of institutions overseeing and guiding it through policies, statutes, and regulations. The result is a dynamic web that provides reliable, affordable, and increasingly clean electricity to our Nation. The U.S. grid delivers approximately 3,857 terawatt-hours of electrical energy from electric power generators to 159 million[5] residential, commercial, and industrial customers.[b] This is accomplished via 19,000 individual generators at about 7,000 operational power plants in the United States with a nameplate generation capacity of at least 1 megawatt (MW).[6] These generators send electricity over 642,000 miles[7] of high-voltage (34 kV and greater) transmission lines and 6.3 million miles[8] of distribution lines. Together with its electric generation component, the grid is sometimes referred to as the world's largest machine; in 2000, the National Academy of Engineering named electrification as the greatest engineering achievement of the 20th century.[9]

Grid of the Future Services

Regardless of the changes the grid will undergo by 2030, there are certain services that customers—whether major industrial consumers or individual residential units—have come to expect from the electricity system. A modernized grid must not only continue to provide these services, but in many instances, expand upon them. These services include the following:

Reliability and Adequacy

Adequate, reliable electric service is the lifeblood of the U.S. economy and essential for our health, safety, and security. New industry and regulatory models should allow for increased levels and forms of reliability, including increased resilience against large-scale power interruptions. At the same time, the system should maintain safeguards that ensure adequate investment in both supply and delivery capabilities.

Affordability and Universal Service

Affordable, high-quality electric service is essential for modern life. The diverse systems in the United States have connected nearly all Americans to affordable electric supplies. The new business and regulatory models must evolve to meet the challenges and opportunities facing the industry. In doing so, they must maintain the twin pillars of "safe and adequate service" at "just and reasonable prices." Consequently, the new models must be designed to ensure that regulated rates and market-determined prices fairly and equitably reflect both costs incurred and value received.

Meeting Climate Change and Other Environmental Goals

To combat threats posed by climate change to the U.S. economy and our security, the Administration has advanced an economy-wide goal of reducing GHG emissions by 26–28 percent below its 2005 level in 2025. The Environmental Protection Agency's proposed Clean Power Plan will cut carbon emissions from the power sector by 30 percent by 2030 (compared to 2005 levels). Additionally, other environmental impacts of electricity provision should be reduced consistent with Federal and state policies. The Clean Power Plan calls for a state-Federal partnership, under which states identify a path forward using either current or new electricity production and pollution control policies to meet the proposed goals of the proposed program. Under the proposal, states can choose the mix of generation using diverse fuels and demand-side management to meet the goals and their own needs.

[b] Here, a "customer" is defined as the electricity consumed 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 electric meter serves 2.5 people.

Allowing for Increased Customer Control, Expanded Service Offerings, and Innovation

A fast-growing group of technologies and data applications are enabling electric customers to measure and control their electric power use to an unprecedented degree, unlocking new services, cost-savings opportunities, and two-way interactions with the power system. New business and regulatory models are needed to facilitate these new services, providing greater value, lower environmental impact, and more efficient grid operations. ***Flexibility*** is a key aspect of both reliability and the ability of the electricity T&D system to provide new services and assimilate new technologies. Flexibility allows infrastructure to accommodate changes in response to new or unexpected system drivers. An important component of flexibility for the electric system is ***interoperability***—the ability to interact and connect with a wide variety of systems and subsystems, both in and outside of the energy sector.

Electric Sector Trends that Affect Service Delivery

How the electricity system continues to provide these services as the system modernizes will be affected by large-scale trends that will shape the geography, architecture, and scale of transformation of the electricity T&D networks. This section describes some of these trends in greater detail.

Shift to Natural Gas

Abundant natural gas supply and comparatively low prices have also affected the economics of electric power markets. Additionally, recent environmental regulations at the local, state, regional, and Federal levels have encouraged switching to fuels with lower emissions profiles, including natural gas and renewables. Natural gas demand for power generation grew from 15.0 billion cubic feet per day (Bcf/d) in 2005 to 21.4 Bcf/d in 2013, and it is projected to increase by another 6.2 Bcf/d by 2030.[10, 11, c] Electricity generation from natural gas rose by 85 percent nationally from 2000 to 2013—from 601 terawatt-hours in 2000 to 1,114 terawatt-hours in 2013.[12] To better understand the scale of natural gas use, total U.S. natural gas consumption in 2013 was 71.6 Bcf/d.[13]

Natural gas-fired power plants accounted for more than 50 percent of new utility-scale generating capacity added in 2013.[14] Natural gas-fired capacity continued to expand in 2014.[15] Infrastructure changes may be needed to accommodate future growth in natural gas use for power, including repurposing and reversals of existing pipelines; laterals[d] to gas-fired generators;[16] more looping and compression to the existing network; potential new pipelines (although, this could be regionalized); and additional processing plants and high-deliverability storage. Under multiple scenarios, the pace of these changes for the interstate natural gas pipeline system through 2030 is projected to be comparable to or less than historical build rates.

With natural gas fueling an increasing share of the Nation's electric generation, the ability of the electricity and natural gas systems to function together is becoming much more important. Interdependency necessitates closer coordination in both planning and real-time operations between the two sectors to assure reliable supply and operations in all conditions of both energy resources to the U.S. economy. A discussion of how overall system flexibility can be enhanced through market and operational processes is discussed in Appendix B (Natural Gas).[e]

[c] Note that the Energy Information Administration 2030 projection does not include laws and policies not enacted or finalized at the time of the projection, thus it does not include any additional natural gas generation under the Environmental Protection Agency's proposed Clean Power Plan. Additionally, the Energy Information Administration's 2030 projection assumes natural gas price increases, as well as new renewables generation still-to-be-built to comply with state Renewable Portfolio Standard mandates.

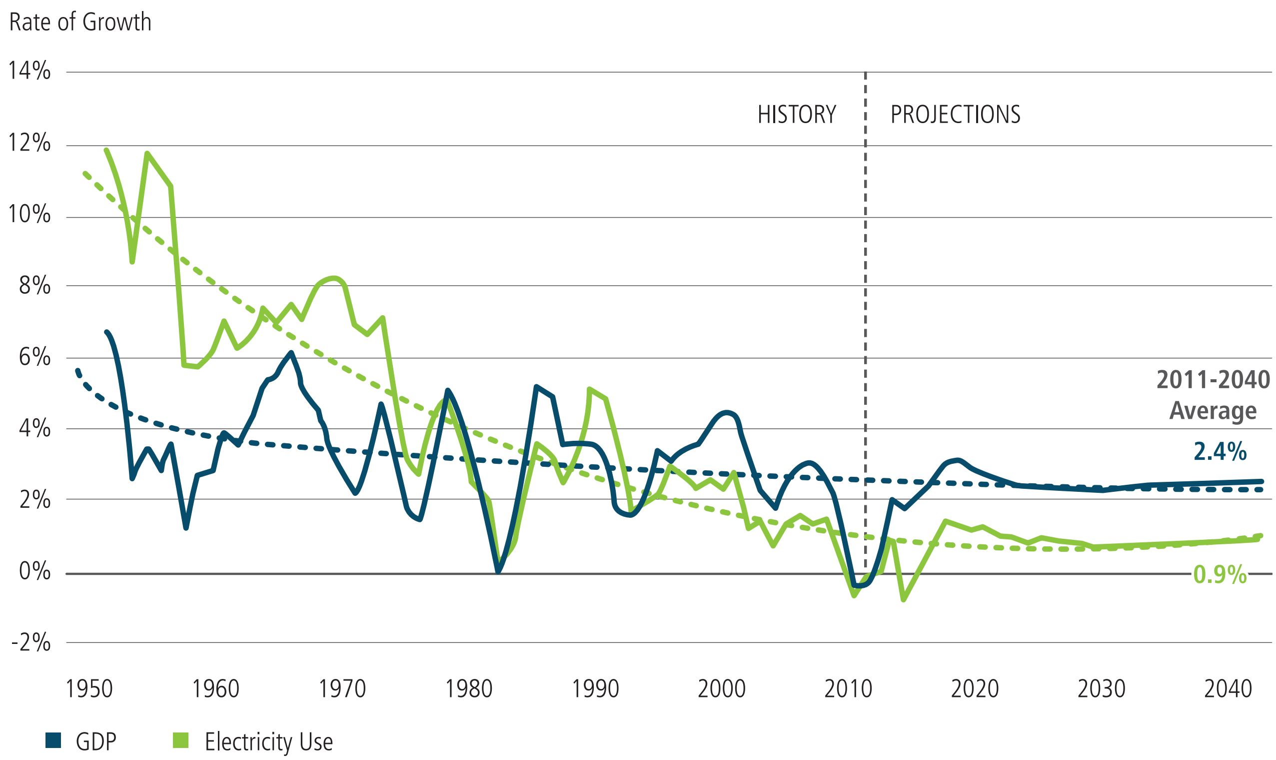
[d] Small segments of pipelines designed to link gas-fired power plants to the natural gas pipeline system.

[e] Extensive discussions between the gas and electric sectors have been and continue to occur at the local, regional, and interconnection-wide levels, as well as through the activities of the Federal Energy Regulatory Commission and the North American Energy Standards Board, among others.

Low Load Growth

The growth rate of total U.S. end-use electricity consumption has been on the decline—even going negative in recent years. In fact, the growth rate of U.S. electricity load (demand) is at the lowest levels since 1950 (see Figure C-3).

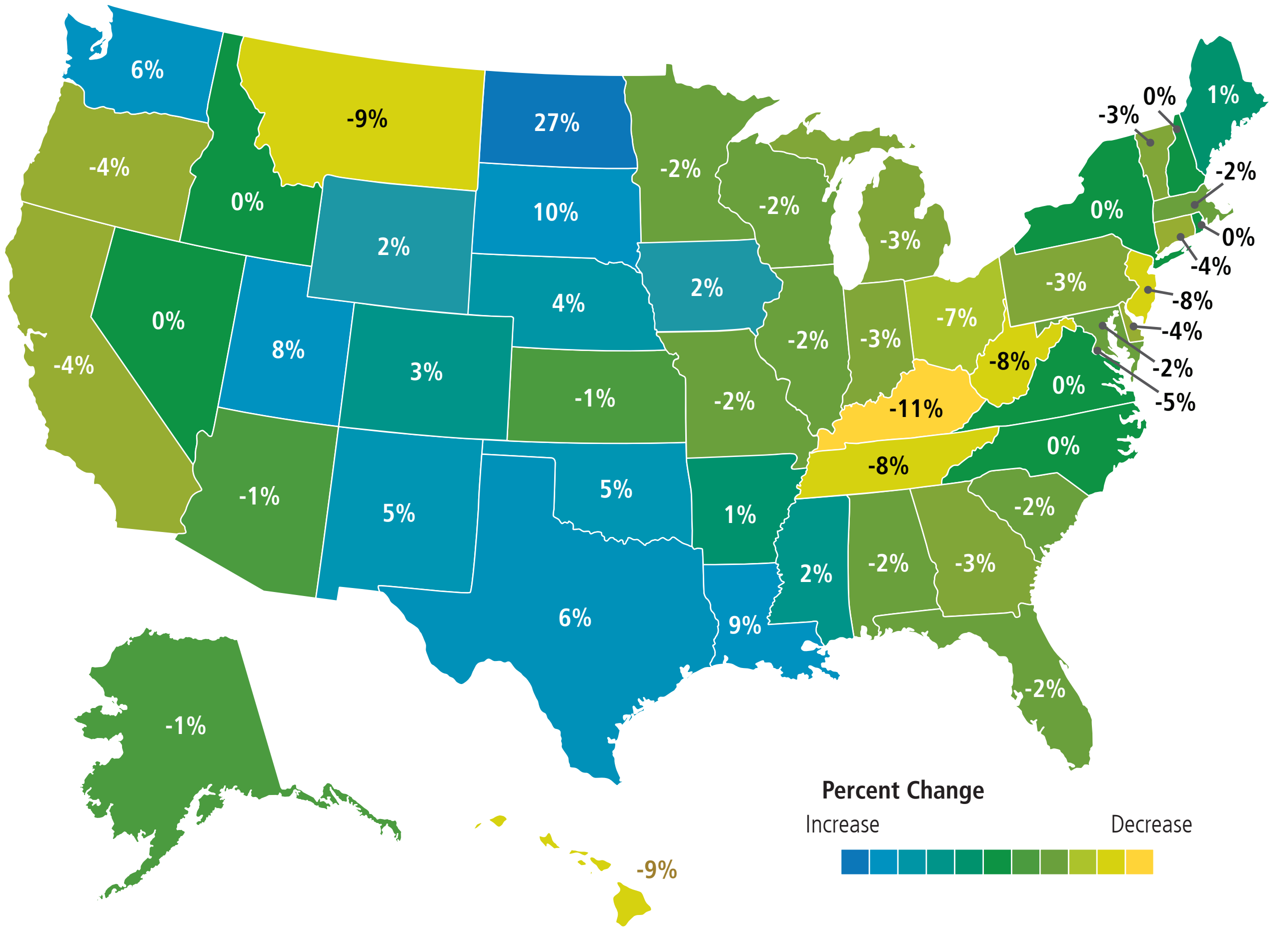
Figure C-3. U.S. Electricity Demand Growth in the EIA 2014 Annual Energy Outlook Reference Case, 1950–2040 (percent)[17]



The rate of growth in electricity use has declined since 1950, while the rate of growth in gross domestic product has stayed relatively constant. The slower electricity growth rate is a result of several factors, including a decline in energy-intensive industries, increasing energy efficiency, and the slow recovery from the recent recession.

Declining demand growth for grid-delivered electricity is driven by long-term structural shifts to a service economy; economics, new technologies, and policies that began improving energy efficiency several decades ago; and more recently, the slow recovery from the 2007–2009 recession, as well as increases in distributed generation (particularly rooftop solar, but also natural gas-fired) in some parts of the United States.[18] Due to regional and local differences, it is important to note that states and regions exhibit substantial variations in their rates of load growth (see Figure C-4).

Figure C-4. Percent Change in Retail Electricity Sales (kilowatt-hours), 2008–2013[19]



There is a considerable variation in electricity retail sales among states and by region, ranging from an increase of 27 percent in North Dakota to a decrease of 11 percent in Kentucky; these variations are due in part to changes in load growth.

Low or declining load growth has several consequences for the electricity TS&D system. Most significantly, new utility business models, with matching regulatory models, may be necessary to incentivize appropriate investment in distribution infrastructure if delivered electricity volumes decline. Without readjusting rates, the traditional practice of relying on volume-based rates for significant portions of capital cost recovery can pose challenges when load growth declines. Adopted during a time of demand growth, volume-dependent rates do not precisely separate grid costs from generation costs. While grid costs (the cost of the wires and distribution equipment from the generator to the house and the maintenance of those wires) tend to be less sensitive to incremental changes in volume delivered, short-term generation costs can be highly variable—largely because fuel and variable operations and maintenance expenses comprise a large portion of the total costs, and they vary significantly by type of generator. Many utility rates do explicitly separate fixed charges and volumetric charges in their customer bills to better recover fixed costs; though, some have argued the fixed charges used do not fully recover all fixed asset costs.[20]

Deployment of Renewable Energy

Renewable capacity has grown dramatically over the past 10 years, and it is projected to continue growing—though at a slower pace—through the end of the decade.[21] Through 2013, growth was largely driven by wind capacity, but the reduction of solar costs and increasing interest in third-party installers has resulted in a dramatic rise in solar capacity growth over the past 2–3 years.

Significant wind additions began in 2006, spurred by state Renewable Portfolio Standards (RPSs), high natural gas prices at the time (that largely drove high wholesale energy prices), the production tax credit, and wind technology cost reductions. U.S. wind capacity is currently 65 gigawatts (GW) with nearly 13 GW under construction.[22] Further, there is potential for another 15 GW based on projections of plants currently in permitting or early-stage development through 2020 based on projections of plants in permitting or early-stage development as of 2013. Generation from wind met 4.1 percent of the total domestic demand in 2013, up from less than 0.5 percent in 2005.[23]

Current solar capacity and output is significantly lower than wind, though it is expected to grow substantially in the next several years.[24] Solar met slightly less than one-quarter of 1 percent of total demand in 2013.[25] While state RPS mandates have goals that require increasing percentages of renewable electricity generation through 2020 (and in some cases, beyond), most regions already have enough renewables capacity under development to meet their 2020 targets.[26] In the regions with the highest-quality wind resources, power purchase agreements for wind power have been reduced to as low as $25 per megawatt-hour after taking the production tax credit ($23 per megawatt-hour) into account.[27] Future expansion beyond the current RPS mandates will be highly dependent on a variety of factors, including whether states choose to increase their mandates; technology advances and any resulting renewables price declines; the price of competing resources; and decisions by the Federal Government on the further extension of the production tax credit and the investment tax credit.

Coal and Nuclear Generation

Market-related factors, including declining growth in electricity demand, lower natural gas prices, and increasing coal prices, are causing significant changes in the electric generating fleet. Due to rising international demand and declines in domestic mining productivity, the Energy Information Administration (EIA) projects steady price increases for coal through 2040;[28] meanwhile, market prices for coal have increased by roughly 70 percent since 2000.[29]

Projections of future coal unit retirements vary, depending on assumptions made about future economic conditions, technology cost and performance, and regulatory requirements. This introduces uncertainty into projections of related TS&D needs.

Coal generation retirements will vary by region, based on the amount of existing coal generation in that region, with thus varying implications for that region's transmission and bulk power system's operations and reliability. System planners in several regions have developed future scenarios that incorporate announced and projected coal unit retirements, and they have begun to use those forecasts to plan for future transmission additions needed to maintain reliability.[30] In some cases, regions with relatively large amounts of announced coal retirements (including the Mid-Atlantic and the Midwest) are pursuing transmission upgrades to reduce costs and/or maintain reliability.[31, 32, 33]

Retirements are also affecting the nuclear power industry, with closures announced in 2012–2013 of five nuclear reactors, the first since 1998. Nuclear power supplied nearly 19 percent of U.S. electricity in 2013, yet only accounts for 10 percent of total installed capacity. Preliminary data for 2014 show a record average 90.9 percent capacity factor for the Nation's 100 nuclear units.[34] Investors and industry experts predict that several more reactors may be at risk for early shutdown, due largely to economic pressure brought on by low electricity prices in Regional Transmission Organization (RTO)/Independent System Operator (ISO) markets and other factors. Factors contributing to the decrease in wholesale electricity prices include the low price of natural gas, low overall electricity demand, and, in some regions of the country, subsidies for renewables that occasionally produce negative prices in RTO/ISO wholesale electricity markets.[f] In addition, new safety regulations resulting from Fukushima and certain environmental regulations are increasing the need for additional capital expenditures at some plants. On the other hand, GHG regulations could make nuclear plants, with zero carbon emissions, more cost effective by internalizing the cost of carbon pollution.

The loss of these plants could lead to a shift in power flows across the transmission system. Since nuclear plants are large (600 MW to 2,300 MW), their loss can be problematic for the transmission system. In 2012, the New York ISO analyzed the implications of shutting down the two Indian Point nuclear units and found that there would be potential deficiencies in power supplied to New York City, violations of reliability criteria, and potentially voltage performance issues.[35]

Earlier, in 2006, a joint study by the National Research Council of the National Academies found that a nuclear "replacement strategy would most likely consist of a portfolio of approaches … including investments in energy efficiency, transmission, and new generation."[36] Following such a strategy, the New York Public Service Commission recently approved a plan to add new transmission facilities and energy efficiency/demand-response measures to address potential problems with Indian Point retirements.[37] A similar case occurred in southern California where the closure of the two San Onofre nuclear units resulted in local reliability concerns for San Diego, as well as local voltage problems. To address these issues, the California ISO approved a new transmission line with an in-service date of 2017 to support the San Diego region.

Not all nuclear plant shutdowns require transmission upgrades or replacement generation; impacts are dependent on the local and regional network topography. For example, when Dominion Resources, Inc. closed its Kewaunee nuclear plant in Wisconsin in 2013, the regional system operator (i.e., Midcontinent ISO) found no transmission issues.[38] The relatively minimal effects of nuclear retirements on transmission are discussed further in the Impact of Nuclear Retirements on Transmission section of this appendix.

Fuel Deliverability

Other near- to mid-term concerns that can potentially stress transmission and reliability are natural gas and coal deliverability. For New England, due to a lack of capacity purchases on pipelines, there is limited natural gas fuel availability at certain peak times, which has shifted dispatch and electric transmission patterns.[39] Transmission lines are being developed and proposed into the New England region, in addition to new pipelines. Low coal inventories at certain coal-fired electric generation facilities have been attributed to limited railroad access,[40] in part caused by the increased usage of rail for transporting crude oil from oil pipeline constrained regions, such as the Bakken Basin in North Dakota and Montana. Supply constraints have occasionally led to plants operating at reduced or minimum load to ensure that they do not deplete their onsite coal supplies prior to replenishment, with potential impacts on reliability.[41] This was the case in Minnesota in 2014, which idled four units due to inadequate coal supplies.[42]

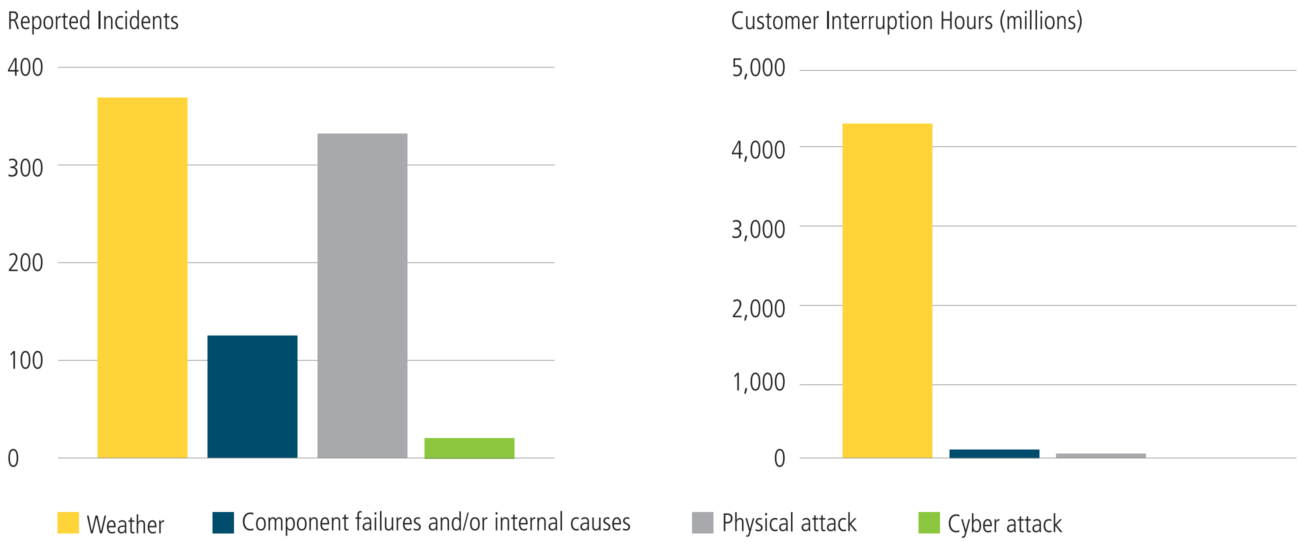
For the long term, significant uncertainties about generation resources translate to similar corresponding uncertainties in the amount and location of new T&D.

[f] Some RTO/ISO wholesale electricity markets have situations that can result in prices below zero. That is, sellers, such as wind generators, pay buyers to take the power so their production tax credit can still be claimed. This situation arises because certain types of generators, such as nuclear, cannot physically shut down for short periods of time when there is excess generation on the system.

Severe Weather and Climate Change

Currently, severe weather events are the largest cause of damage to grid infrastructure and disturbances to electricity service. As Figure C-5 indicates, from 2011 to 2014, weather-related events triggered the greatest number of reported electric disturbances and had far greater impacts on electricity service than component failures, physical attacks, and cyber threats. Because the United States has a well-maintained grid, service interruptions due to equipment failures and poor operation are not common. Weather is the leading cause of grid disturbances, particularly at the distribution level, but causes vary by region and include, in addition to weather, types of vegetation, as well as vegetation management and other maintenance practices.

Figure C-5. January 2011–August 2014 Electricity Disturbances Reported to the Department of Energy[43]



Weather-related events triggered the greatest number of reported electric disturbances and had far greater impacts on electricity service than component failures, physical attacks, and cyber threats. Incidents vary by region and are not just due to weather, but also due to types of vegetation, as well as vegetation management and other maintenance practices. Not all incidents, such as voltage reductions and public appeals, result in actual customer outages.

Weather-related outages are estimated to have cost the U.S. economy an inflation-adjusted average of $18 billion to $33 billion per year between 2003 and 2012,[44] and some estimates are even higher.[45] There may be an emerging trend of growing frequency and magnitude of weather-related outages to the distribution system. Unfortunately, data collection on outages is not standardized—either across states or across the utility industry at the distribution level where most outages occur. Only in the last several years has collection of data through the Department of Energy's (DOE's) Form OE-417 been more thorough, and thus a comprehensive and accurate long-term trends analysis is not possible from which conclusions can be drawn.

While electricity services in all regions of the country are affected by weather-related outages, "year-in-review" reports published by DOE since 2010 illustrate that certain regions typically are affected more by certain types of weather events.[46] For example, tropical storms and hurricanes most frequently cause outages in the Gulf Coast and Atlantic regions. Tornado outbreaks most commonly disrupt service in the Midwest. Severe thunderstorms can cause problems in most regions, but particularly in the Midwest, Southeast, and Mid-Atlantic regions. Winter storms also have been responsible for disruptions in many regions; the eastern United States has been affected most frequently, though the Pacific Northwest, California, and Texas also are impacted. The West sees many outages caused by lightning and wildfires. The Santa Ana winds are a relatively unique challenge for southern California.

An increase in the frequency of disruptive extreme weather events is the primary way in which climate change is expected to further impact energy infrastructure.[47] Trends toward more frequent and more intense heatwaves, droughts, wildfires, heavy precipitation events, and coastal flooding have been observed and attributed to climate change,[48] and these trends are projected to continue.[49] Additionally, sea-level rise will exacerbate the potential for climate change to bring more frequent hurricanes on the high end of the Saffir-Simpson Hurricane Scale (e.g., Category 4 and 5 hurricanes may become more common).[50] Weather events reduce system deliverability, primarily due to high winds, lightning, or wildfires that can cause damage on the T&D network.[51] Sea-level rise and storm surge expose distribution substations, transmission structures, and power plants to flooding.

U.S. temperatures are projected to continue rising in the coming decades.[52] Electricity T&D systems carry less current and operate less efficiently when ambient air temperatures are higher.[53] In addition, increasing temperatures likely will increase electricity demand for cooling, which could increase utilization of T&D systems during peak-demand periods. Increasing air and water temperatures reduce the efficiency of power plant cooling, which increases the risk of partial or full shutdowns of generation facilities during heat waves.[54] Additionally, case studies indicate that sudden, extreme heat can cause transformers to malfunction or stop working.[55]

Cyber and Physical Threats and Geomagnetic Storms: High-Consequence, Low-Probability Events

Non-routine system disruptions may occur due to extreme weather events, cyber and physical attacks, and electromagnetic or geomagnetic pulses. The North American Electric Reliability Corporation (NERC) quantifies the stress from events resulting in mostly bulk power level loss of generation, transmission, or load in its Daily Severity Risk Index. NERC notes that its index (which excludes most weather effects due to bulk power system focus) "has been stable to improving from 2008 to 2013."[56] However, recent events reveal how susceptible critical infrastructure is to disruptions and the importance of resiliency to a wide range of hazards.[57] Human-made and natural threats will continue to grow in frequency and magnitude;[58] as a result, a resilient grid posture will be needed in order to maintain services.

Modern power systems rely heavily on automation, centralized control of equipment, and high-speed communications to increase efficiency and improve awareness. Those same systems also make the grid vulnerable to cyber threats. Vulnerabilities include industrial control systems, grid devices capable of two-way communications, outdated network access systems (such as dial-in access), and international supply chains related to smart grid components.[59] The most critical systems are the supervisory control and data acquisition systems that gather real-time measurements from substations and send out control signals to equipment, such as circuit breakers. If breached, hackers could manipulate supervisory control and data acquisition systems to disrupt the flow of electricity, transmit erroneous signals to operators, block the flow of vital information, disable protective systems, and even impart physical damage on facilities. Cyber threats have not yet caused extended outages, but if well-coordinated, they could magnify the damage of a physical attack. For example, a cascading outage could be aggravated if operators do not receive timely notification, or if protective devices are disabled.

The range of physical threats to system elements has expanded from occasional acts of vandalism or minor theft to include coordinated attacks, and recent attacks have raised the awareness of electric infrastructure vulnerability. Loss of system functionality caused by physical attacks can result in instability, uncontrolled separation, or cascading failures.[60, 61] For example, in April 2013 at Pacific Gas and Electric Company's 500-kV Metcalf substation, assailants outside the substation reportedly shot at the high-voltage transformer radiators with large-caliber bullets, causing them to leak cooling oil, overheat, and become inoperative. While the attack knocked out 17 transformers that funnel power to Silicon Valley and took 27 days to repair, service was not interrupted to customers.[62] In another case, there was an attack on the transmission grid in Arkansas in October 2013, including a deliberately set fire at Entergy's 500-kV substation in Lonoke County.[63] Other attacks on substation equipment have been reported with some regularity, although most have been attributed to vandals.[64]

Geomagnetic storms are another vulnerability that poses increased risk, especially as the reliance of critical infrastructures on electricity increases. These storms arise from the interaction of the solar wind with Earth's magnetic field. Storm-time geomagnetic activity induces electric fields in the electrically conducting lithosphere, and these, in turn,[65] can drive uncontrolled currents in power grids that interfere with their operation. Though the probability of an extreme geomagnetic storm is relatively low, the occurrence is almost inevitable at some point in the future. Geomagnetic storms have the potential to damage transformers and other critical grid assets over large geographical areas. A geomagnetic storm in 1989 resulted in a blackout in Montreal and most of the Province of Quebec.[66]

More recently an intense geomagnetic storm caused a blackout in Malmo, Sweden, and damaged several transformers in South Africa. Economic and societal costs attributable to impacts of geomagnetic storms could be very large.[67] A 2013 Lloyds of London report indicated that geomagnetic disturbances could cost the economy as much as $2.6 trillion and take 1–2 years for a full recovery (for perspective, the Northeast blackout in 2003 was estimated to have cost between $4–$10 billion).[68]

Improving Cybersecurity in the U.S. Energy Sector

The cyber threat to critical infrastructure continues to grow and represents a serious national security challenge for the United States. Federal, state, local, tribal, and territorial entities, as well as public and private owners and operators, share responsibility for proactive, coordinated efforts that strengthen the security and resiliency of critical infrastructure.

In February 2013, President Obama issued Executive Order No. 13636, *Improving Critical Infrastructure Cybersecurity*, and Presidential Policy Directive-21, *Critical Infrastructure Security and Resilience*. These policies reinforce the need for holistic systems that address security and risk management in the energy sector. In February 2014, the Obama Administration launched the Cybersecurity Framework to assist organizations in enhancing critical infrastructure cybersecurity. In January 2015, the President issued an updated legislative proposal for a national data breach notification standard, a bill to enhance law enforcement tools for combatting cybercrime, and a bill to promote better cybersecurity information sharing. In February, the President issued Executive Order No. 13691, *Promoting Private Sector Cybersecurity Information Sharing*, to promote private sector information sharing through the creation of information sharing and analysis organizations. In April, President Obama issued Executive Order No. 13694, *Blocking the Property of Certain Persons Engaging in Significant Malicious Cyber-Enabled Activities*, to provide the Treasury Secretary with the authorities to impose sanctions upon malicious cyber actors who seek to disrupt or destroy U.S. critical infrastructure, including that within the energy sector.

While the Department of Homeland Security (DHS) coordinates the overall Federal effort to promote the security and resilience of the Nation's critical infrastructure, in accordance with Presidential Policy Directive-21, the Department of Energy (DOE) serves as the day-to-day Federal interface for sector-specific activities to improve security and resilience in the energy sector. While this report does not go into detail on cybersecurity, the Federal Government and others have a range of activities underway to improve cybersecurity of critical infrastructure. Improving security and resilience includes accelerating progress in the following areas relevant to the Quadrennial Energy Review:

1. **Build robust information-sharing architecture across the energy sector.** Robust information sharing between government and industry, and among owners and operators, is critical for addressing cyber threats. Entities like the three Information Sharing and Analysis Centers within the U.S. energy sector and Information Sharing and Analysis Organizations (as encouraged by Executive Order No. 13691) help propagate information on cyber threats, vulnerabilities, incidents, and solutions in the energy sector. Energy sector organizations can participate in information sharing with DHS's National Cybersecurity and Communications Integration Center, including via automated, machine-readable methods wherever possible. Such information sharing can occur directly or via an Information Sharing and Analysis Center.

Improving Cybersecurity in the U.S. Energy Sector (continued)

2. **Expand implementation of best practices and sound investments by owners and operators.** The Cybersecurity Capability Maturity Model, developed by DOE in partnership with industry and others, can identify and assess various practices for energy sector cybersecurity. In many cases, there is an opportunity for owners and operators of critical infrastructure to invest more in people, processes, and technology that can improve security and resilience. The model can assist those responsible for overseeing cybersecurity decisions. More broadly, energy sector organizations can use the Cybersecurity Framework as part of an enterprise risk management approach. DHS's Cybersecurity Critical Infrastructure Community Voluntary Program offers tools and resources to support use of the Cybersecurity Framework.
3. **Develop and deploy cutting-edge technical solutions.** Experience indicates that proactive measures taken on the basis of advanced research and development can provide a defensive edge. DOE has partnered with energy sector owners, operators, and vendors since 2006 to research, develop, and demonstrate cybersecurity solutions according to a set of near-, mid-, and long-term objectives outlined in the Roadmap to Achieve Energy Delivery Systems Cybersecurity, which was developed through government-industry partnership.
4. **Build a strong incident management capability.** Government and industry are continuing to enhance their capabilities to respond to serious cybersecurity incidents in the energy sector. This includes information-sharing processes, mitigation strategies, training, and resources. Incident response plans need to be developed, vetted, and tested through progressively challenging exercises, culminating in a "capstone" exercise like GridEx, which is hosted by the North American Electric Reliability Corporation. Future exercises could address the interdependency between the electricity subsector and the oil and natural gas subsector.

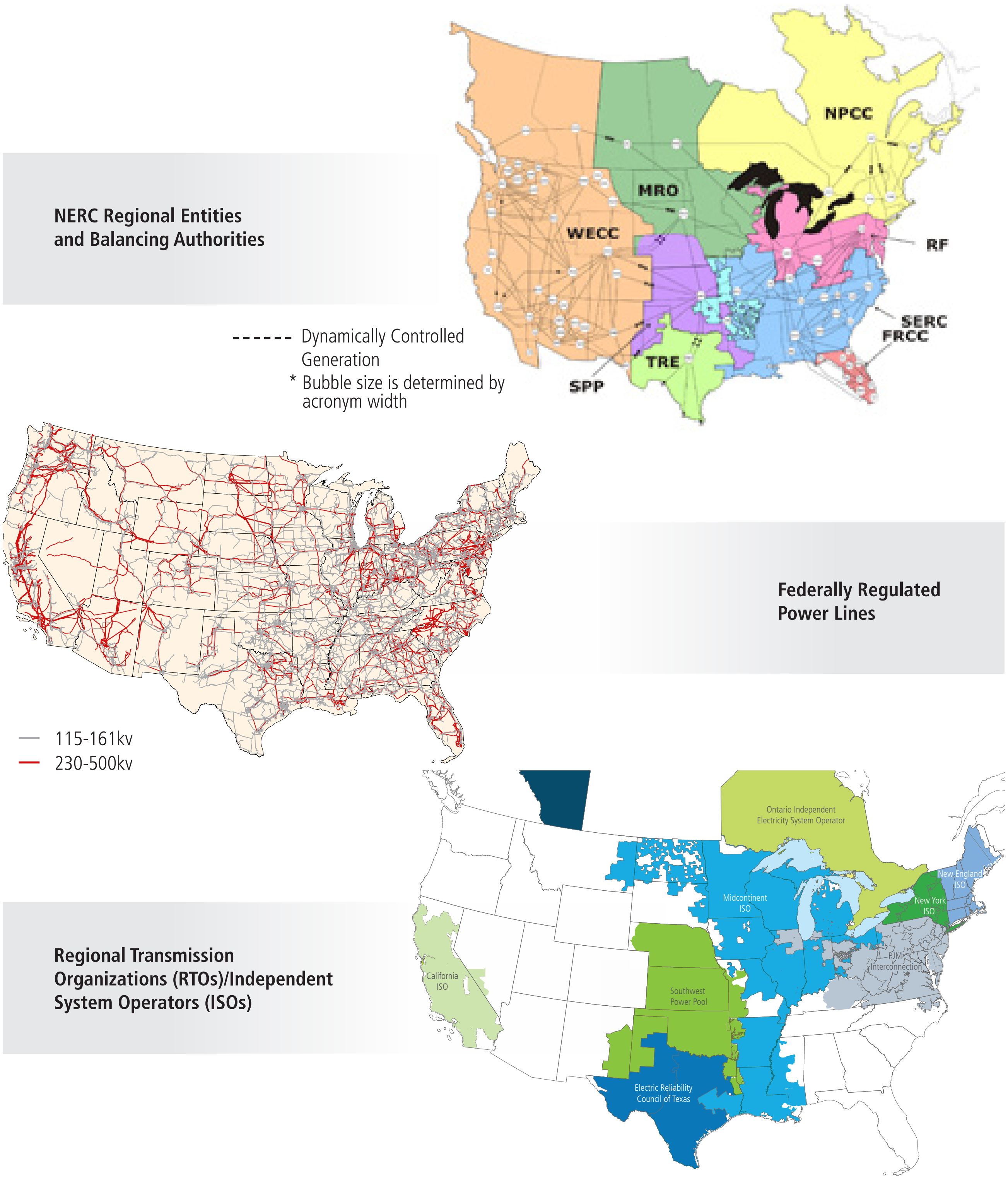
Interacting and Overlapping Jurisdiction

Federal, regional, and state institutions and regulatory structures that have evolved over decades to manage the electric grid are increasingly interacting and overlapping. The geographical boundaries of the institutions are not coincident with the flow of electrons on the physical system. The increasing physical complexity of the grid will only complicate governance and analysis. Policymaking to address regulatory and operational challenges of the evolving grid is more difficult because models used to analyze the physical flows of electricity do not align with the institutional and regulatory structures (see Figure C-6).

The current Federal-state regulatory boundary dates back to the 1930s, when the Federal Power Act substantially expanded the responsibilities of the Federal Power Commission (the predecessor to the Federal Energy Regulatory Commission [FERC]) and created Federal oversight of wholesale sales of electricity and transmission of electricity in interstate commerce, as well as state oversight of retail sales and distribution of electricity. In recent decades, organized wholesale markets have spread geographically and incorporated a greater variety of products with a broader set of market participants. This trend—coupled with the increased ability of end-use consumers to supply distributed generation, demand response, and other services—has and will continue to raise questions about the dividing line between state and Federal jurisdiction.[g]

[g] See, for example, Electric Power Supply Association v. FERC, 753 F.3d 216 (D.C. Cir. 2014). Petition for certiorari granted.

Figure C-6. Select Electricity Jurisdictions[69]



Transmission lines are regulated at the Federal level with regard to their rates, terms, and conditions of service. In contrast, states regulate the distribution of electricity to end-use customers for entities under their jurisdiction, as well as the siting of transmission on non-Federal lands by non-Federal entities. Further, in most states, local appointed or elected governing boards handle the regulation of distribution for their publicly or cooperatively owned electric utility. This diversity of institutions and differences in jurisdictional boundaries create challenges in grid governance (given that changing the grid in one location can alter electricity dynamics over a large area).

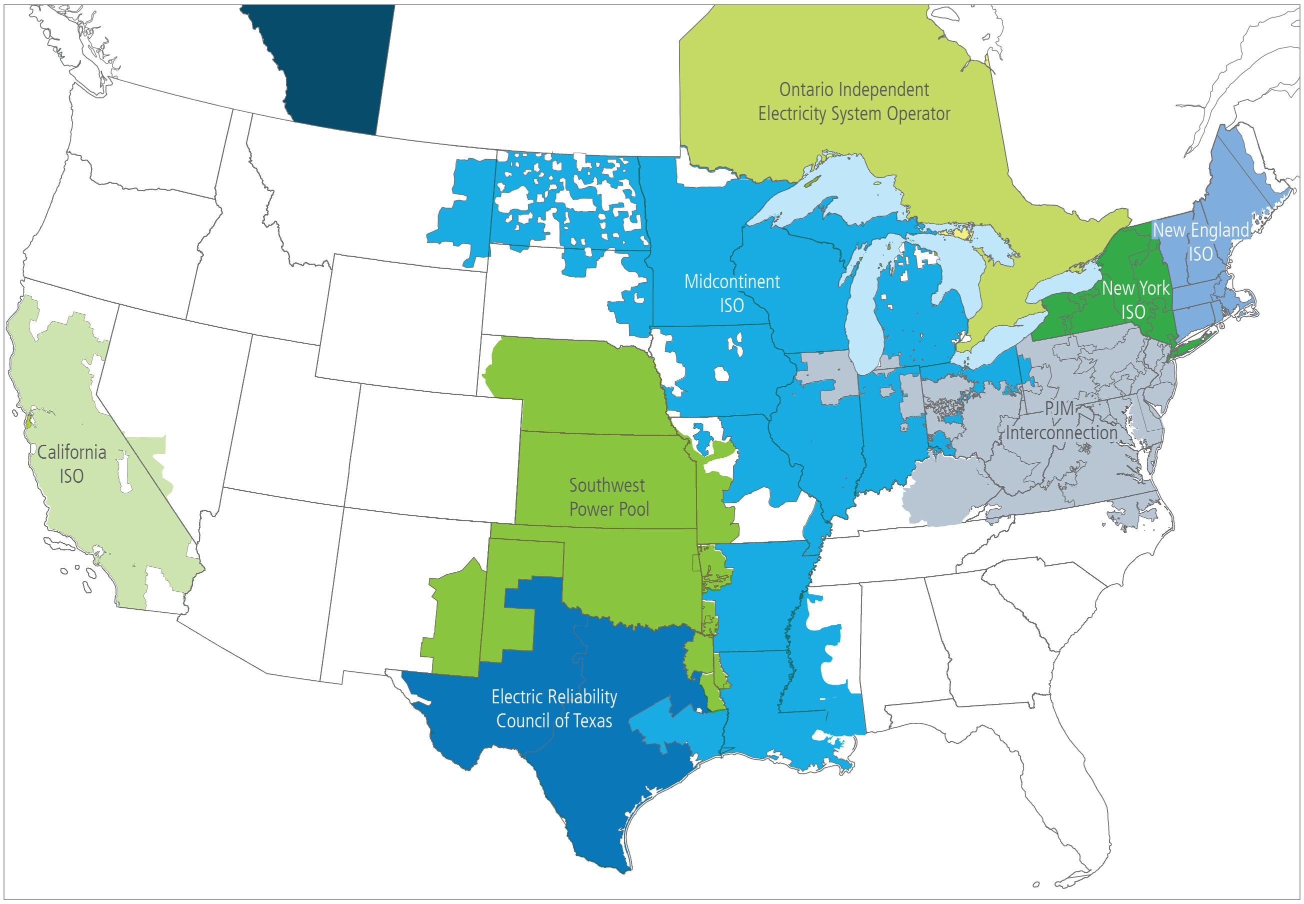
The new concept of "transactive energy," discussed in more detail later in this appendix, spurred by new and emerging distribution- and customer-based technologies, may pose the biggest single "new" factor where the physical grid operations and the policy and regulatory oversight jurisdictions that exist today will not fully align.

Predominately, electricity flows from wholesale markets serviced by central station generation to retail markets (i.e., end users) unidirectionally from generation, through transmission, to distribution, to the final customer. With the emergence of "transactive energy" (including demand response, storage, and customer-owned generation) increasing in some regions of the United States, some amounts of electricity can move from the customer to the grid, creating more bidirectional flows. New distribution and customer-based technologies can conceivably provide services to the grid itself. As those flows from customers increase, they will increasingly affect the planning and operations of the distribution system, and if and when large enough, the transmission system.

In parallel, increasing interest in applying the Federal ratemaking processes associated with the Public Utilities and Regulatory Policies Act of 1978 to state decisions affecting retail net metering tariffs for distributed generation is creating a new dynamic in jurisdiction issues. The Public Utilities and Regulatory Policies Act of 1978 is a statute based on cooperative federalism. FERC issues regulations to give effect to the statute's requirements, and states are responsible for implementing those FERC regulations.

Technology, market, and regulatory changes are already creating a new landscape for independent governance structures. In the early decades of the electric power industry, almost all utilities generated, transmitted, and distributed power within the confines of a single state. Over time, however, trade across state lines opened up opportunities to reduce costs and increase reliability. Some companies formed power pools to facilitate the coordination of generation so that it could be moved over transmission lines to distant markets, often in other states. For example, PJM started in 1927 when three utilities with operations in several states formed the world's first power pool.[70] A number of subsequent developments also have had important impacts. The Energy Policy Act of 1992 mandated that all transmission owners provide non-discriminatory access to transmission to facilitate competition. FERC Order Nos. 888 and 889 advanced similar goals, establishing requirements that public utilities provide open access to their transmission facilities. FERC Order No. 2000 further encouraged transmission owners to join and transfer operational control of their transmission facilities to an ISO or RTO. Figure C-7 shows the ISO/RTO regions as of July 2014.

Figure C-7. Service Territories of the Nine North American RTOs/ISOs[71]



Except for the Southeast and non-California West, organizations known as ISOs or RTOs exist in the United States to plan and operate the grid and run centrally organized wholesale electricity markets.

ISOs and RTOs also conduct regional transmission planning and submit tariff proposals to FERC for allocating the costs of corresponding transmission facilities. States in these regions frequently play a role in stakeholder negotiations on those tariff proposals, as well as maintaining their traditional primary role in transmission siting. More recently, FERC issued Order No. 1000, which concerns transmission planning and cost-allocation procedures. Among other things, Order No. 1000 requires transmission providers subject to FERC jurisdiction to participate in a regional transmission planning process that provides for consideration of transmission needs driven by public policy requirements, which may include enacted state policies.

Today, ISOs/RTOs are responsible for many aspects of reliable and economic wholesale grid systems operations within their geographic footprint. Some ISOs/RTOs, such as ISO New England and the New York ISO, adopted the service territories of pre-existing "tight" power pools. Others, such as the Midcontinent ISO, developed where no such power pool previously existed. Some states, such as New York, California, and Texas, have ISOs that are wholly located within the states. Other ISOs/RTOs, such as PJM, have discontinuous boundaries.[h]

[h] Utilities are not obligated to join a particular RTO/ISO. Rules for joining and obligations of membership differ; utilities therefore choose on the basis of corporate interests rather than exclusively on geographic location.

Even outside of regions served by RTOs/ISOs, transmission systems owned by FERC-jurisdictional transmission providers are subject to open and non-discriminatory transmission access requirements set forth by FERC Order No. 888 and subsequent orders. In these regions, companies may conduct electricity transactions on a bilateral basis, rather than through organized wholesale electricity markets. Entities trade when they can benefit from buying or selling power with other generation.

Perhaps the oldest issue affected by differing jurisdictional oversight is siting of interstate transmission lines. While the Energy Policy Act of 2005 gave FERC limited "backstop" siting authority over interstate transmission lines, a subsequent Fourth Circuit decision rejected FERC's effort to implement that authority. Meanwhile, states in the Midwest, West, and New England have created regional siting protocols, tool kits, or collaborative organizations to promote more efficient, fair, and timely decisions. The Council of State Governments has furthered these moves toward more effective collaboration by issuing interstate compact language so that state legislatures can more easily pursue interstate transmission siting cooperation. The Federal Government has several efforts underway to improve siting and permitting of TS&D infrastructure, including transmission lines. These efforts are particularly vital in the West where the Federal Government is a major landowner. The complexity and pace of the Federal permitting and review processes for proposed infrastructure projects has been identified as a key challenge to building TS&D infrastructure on Federal land.[72, 73]

Transmission

Role and Physical Characteristics of System

Transmission is the high-voltage transfer of electric power from generating plants to electrical substations located near demand or load centers; step-down substations are the boundary between the transmission system and the distribution system that serves retail customers. The United States has about 642,000 miles[74] of high-voltage (34 kV and greater) transmission lines. Of this amount, NERC identifies roughly 170,000 miles as more than 200 kV among a range of voltage classes, mostly alternating current with some as direct current (see Table C-1).

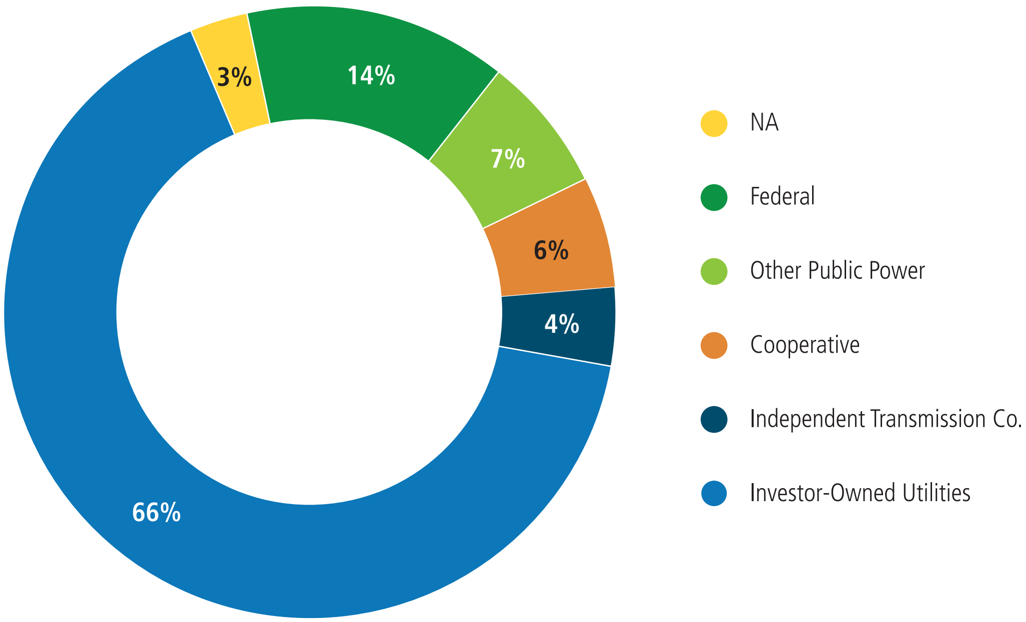
Table C-1. Approximate Distance of Transmission Lines by Voltages over 200 kV[75]

Line Type	Voltage (kV)	Miles
Alternating Current (AC)	200-299	84,000
	300-399	54,000
	400-599	26,000
	≥ 600	2,400
	Total ac	161,000
Direct Current (DC)	200-299	700
	300-399	0
	400-599	1,800
	≥ 600	0
	Total dc	2,500
	Total	169,000

Comparison of alternating current and direct current transmission capacity by voltage and distance.

Transmission lines are primarily owned by investor-owned utilities (IOUs), public power utilities, and cooperative entities, but new forms of ownership, including independent transmission companies and "pure-play" merchant transmission firms, are beginning to develop and own transmission. For the new transmission-focused entities, the core business and potential source of profits is based on acquiring, developing, building, and operating transmission. Figure C-8 illustrates shares of ownership of high-voltage transmission capacity by the type of entity that owns the capacity.

Figure C-8. High-Voltage Transmission Ownership[76]



This figure illustrates the pattern of ownership of high-voltage transmission lines. Currently, transmission lines are primarily owned by IOUs, public power utilities, and cooperative utilities within each interconnection, but new forms of ownership, including independent transmission companies and "pure-play" merchant transmission firms, are beginning to participate.

Transmission System Vulnerabilities

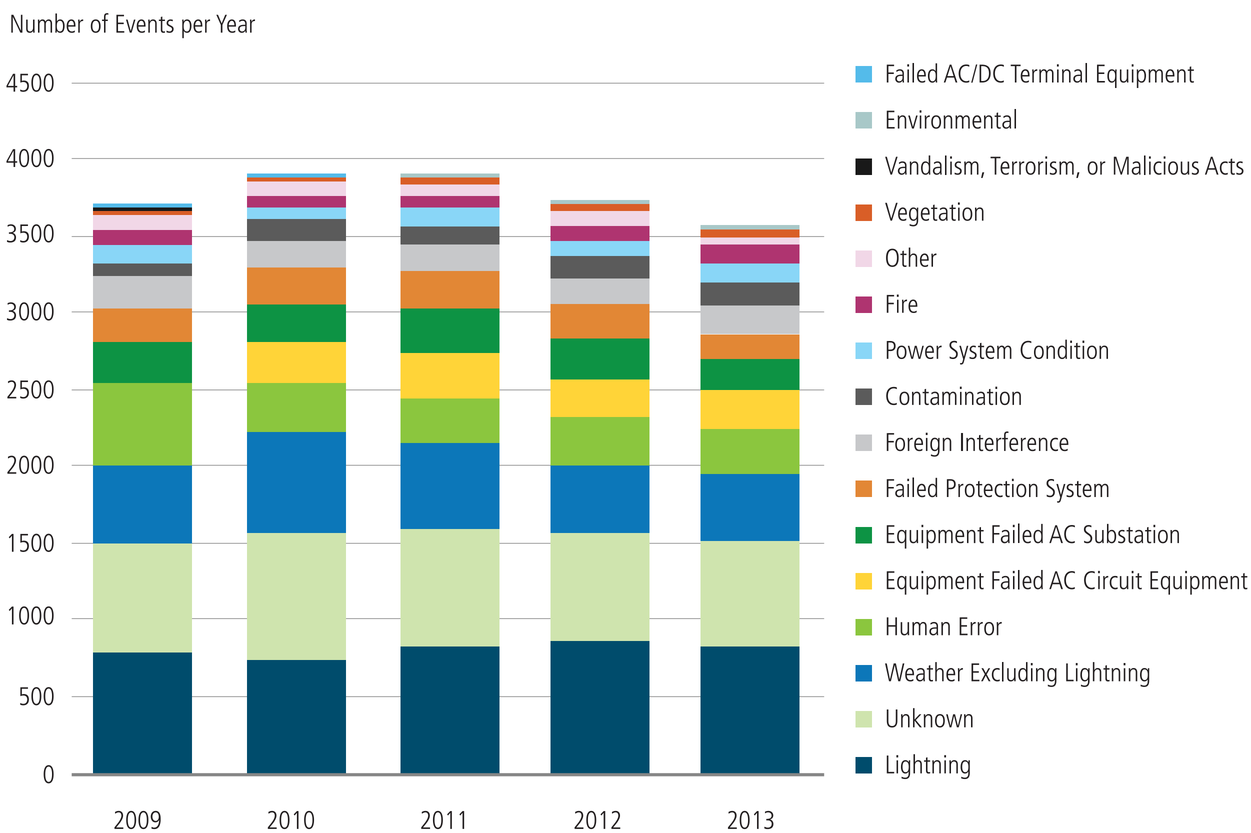
Although major bulk power system and associated transmission outages can and have led to widespread blackouts, they are rare. A recent example of such a blackout occurred in the eastern United States on August 14, 2003, and affected an estimated 50 million people in the Midwest, Northeast, and Ontario. The blackout lasted up to 4 days in some states and an entire week in parts of Ontario. In its 2004 final report on the causes of the blackout, the U.S.-Canada Power System Outage Task Force identified four "groups" of causes, sometimes summarized as "tools, trees, and training:"[77]

- Failure to determine and understand inadequacies with respect to voltage instability
- Failure to establish appropriate transmission constraints and then monitor them
- Failure to adequately manage tree growth along transmission rights of way
- Failure of the reliability coordinator in lacking the data and systems to detect and be aware of the situation as it unfolded.

The transmission network experiences a wide variety of natural disturbances, such as lightning, fire, wind, ice, wildlife, and vegetation. Human-caused disturbances also occur, whether due to negligence or malicious intent. However, the vast majority of these disturbances do not result in widespread blackouts. For events that do result in the failure to serve large portions of the load, the industry has implemented processes to identify and correct the causes of blackouts.

Planning standards require the bulk power system to be built so that any single (and many double) points of failure do not result in loss of load.[78] Figure C-9 shows the causes for transmission-level outage events, as recorded in the NERC Transmission Availability Data System.[79] While lightning and non-lightning weather causes are associated with the largest number of recorded outages, protective devices and other designed-in contingency measures can clear and restore these momentary events quickly, reducing their impact on system reliability.

Figure C-9. Causes of Transmission Outage Events (from the NERC Transmission Availability Data System)[80]



The causes of transmission outages vary by region, as well as by their cause.

A transmission outage will increase the vulnerability of the system to additional outages, but it does not mean that the transmission outage will result in a loss of load affecting customers or, in the extreme, a cascading blackout affecting customers widely in many states.

Even in cases of widespread weather events, the transmission system has not been the primary cause of customer outages. While Hurricane Sandy damaged some transmission facilities, ISO New England, PJM Interconnection, and New York ISO were able to maintain bulk power system operation through the storm.[81] An analysis of the 2012 Derecho, 2011 Hurricane Irene, and 2010 "Snowmageddon" storm showed that the majority of outages in the State of Maryland were due to distribution network rather than loss of power from the transmission feeder.[82] A review of the January 2014 polar vortex found that outages were due primarily to fuel supply and generator availability rather than transmission unavailability.[83]

In rare instances, a combination of high system stress and human error can result in large-scale outages, as with the largest blackout since 2000—the August 14, 2003, blackout discussed earlier. On February 26, 2008, the manual disabling of protection systems was a major factor leading to a blackout affecting 954,000 customers in Florida.[84] On September 8, 2011, a "lack of adequate planning and situational awareness" led to an insecure system state and was the major factor in a blackout that affected 2.7 million customers in Arizona, California, and Baja California.[85]

Transformers: A Critical Component

While transmission towers and large high-voltage transformers are both potential vulnerability points,[i, j] physical attacks on towers generally have not resulted in widespread outages because utilities are able to rapidly recover from isolated tower damage.[k] In contrast, high-voltage transformers are difficult to replace because each unit weighs 100–400 tons and is custom built, requiring up to 20 months or more to procure, move, and install.[l] The United States has never experienced simultaneous failures of multiple high-voltage transformers, but a coordinated and simultaneous attack on a small number of these transformers in critical network locations could cause widespread, extended blackouts.[m] In addition to physical attacks, induced currents from geomagnetic storms could also damage high-voltage transformers.

i National Research Council. "Terrorism and the Electric Power Delivery System." 2012.

j Congressional Research Service. "Physical Security of the U.S. Power Grid: High-Voltage Transformer Substations." 2014.

k Congressional Research Service. "Physical Security of the U.S. Power Grid: High-Voltage Transformer Substations." 2014.

l Congressional Research Service. "Physical Security of the U.S. Power Grid: High-Voltage Transformer Substations." 2014.

m National Research Council. "Terrorism and the Electric Power Delivery System." 2012.

In response to the 2003 blackout, the Energy Policy Act of 2005 directed FERC to certify an electric reliability organization that would be responsible for developing mandatory and enforceable reliability standards for the bulk power system.[86] FERC has certified NERC as that electric reliability organization. FERC reviews NERC's proposed reliability standards, which become mandatory and enforceable after FERC approval. FERC also may direct NERC to develop such standards. In addition to its stakeholder-based standards development process, NERC also conducts detailed post-outage event analyses to obtain and share lessons learned.[87] NERC is transitioning to a risk-based monitoring and enforcement program, which encourages the industry to proactively self-identify and correct reliability issues.[88] Finally, the standards development process can adapt to emerging threats, as exhibited by continual revisions to cybersecurity standards[89] and development of a physical security standard for certain types of facilities.[90]

Changes Affecting New Transmission Investment

Transmission planning, development, and investment activity has been on the rise for over a decade. As an asset class, transmission attracts significant investment from utilities, financial investors, and project developers. Transmission spending for IOUs rose from $2.7 billion in 1997[91] to $14.8 billion in 2012[92] (2012 dollars). The most recent data on transmission investment for IOUs was $16.9 billion in 2013—a 14-percent increase from 2012 ($14.8 billion).[93]

The Edison Electric Institute (EEI) "attribute(s) the increased transmission investment to…new technologies for improved system reliability, development of new infrastructure to ease congestion, interconnection of new sources of generation (including renewable resources), and support for production of shale gas," as well as "improvements to integrate new resources and increase system hardening, resiliency, and security."[94] Distribution system additions from IOUs, as reported by EEI (2013 dollars) have risen from about $19.5 billion (2013 dollars) in 1994 to about $20.1 billion in 2013.[n, 95] EIA notes that distribution investments rose even as U.S. electricity sales have decreased in 4 of the 5 years from 2009 to 2013.[96]

Regionally, transmission investment differs significantly, reflecting local circumstances. The California and New England ISOs have had the most investment per megawatt of demand between 2008 and 2012—three to four times the level in other regions around the country (see Table C-2). More recently, major transmission build-outs are occurring in the Midwest (Midcontinent ISO) and middle South (Southwest Power Pool) footprints. Analysis done for the Western Electricity Coordinating Council's 10-year transmission plan shows that sufficient transmission is being developed in the Western electricity interconnection to meet all projected needs through 2024, including satisfying state RPS mandates.[97] In 2005, the Texas legislature enacted legislation that required the Texas Public Utilities Commission to identify "Competitive Renewable Energy Zones" (CREZs) where wind generation can be built. In 2008, the commission designated five CREZs and put in motion a $4.93-billion program to build 2,400 miles of new transmission by nine utilities, which subsequently enabled approximately 18,500 MW of wind resources to be developed and moved from west Texas to the Texas grid. The last of the seven CREZ transmission lines was energized in December 2013.[98, 99]

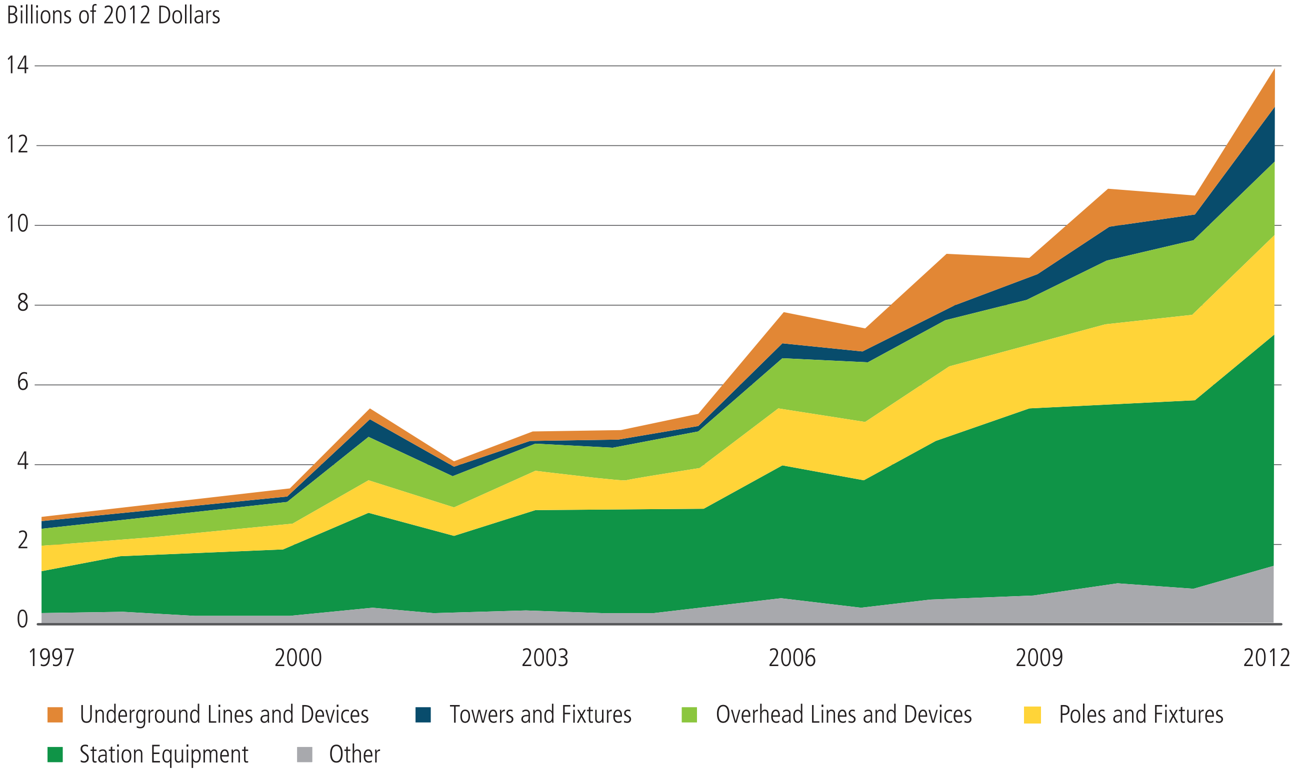
Table C-2. Analysis of Transmission Investment per Megawatt of Peak Demand from 2009 to 2013[100]

Region	2009	2010	2011	2012	2013	Average
PJM	$16,457	$18,776	$28,952	$22,191	$29,238	**$23,100**
MISO	$20,162	$15,871	$13,788	$20,292	$31,734	**$20,400**
SPP	$13,926	$20,344	$13,810	$28,062	$19,707	**$19,200**
CAISO	$50,713	$35,766	$29,350	$106,322	$100,514	**$64,500**
ERCOT	$10,243	$12,144	$15,560	$17,141	$34,867	**$18,000**
ISO-NE	$32,419	$23,757	$30,213	$76,475	$71,242	**$46,800**
NYISO	$11,199	$22,295	$28,595	$14,399	$12,093	**$17,700**
TOTAL US	$16,607	$17,513	$18,543	$24,339	$28,526	**$21,100**

Regionally, transmission investment reflects different circumstances. Transmission investment in a region will also vary by years in a region, thus this table would change if done in a different time period. In the table, the "Total US" line refers to averages over all regions in the table for that particular year. Analysis is based on estimated total industry annual investment divided by peak demand in each year. Data for all regions is based on annual investment by FERC Form 1 filers (estimated to represent 70 percent of total industry investment) grossed up to 100 percent of the industry to reflect investment from electric cooperatives, public power, and Federal Power Marketing Administrations and the Tennessee Valley Authority. Southwest Power Pool peak demand is based on reliability footprint. Annual investment values are in nominal dollars. Transmission development and planning activity has been on the rise for over a decade, as is seen in Figure C-10.

[n] The amount of $19.5 billion is inflation-adjusted to 2013 by using inflation factors from Handy-Whitman index of public utility construction costs applied to 1994 distribution spending in "Table 9.1: Construction Expenditures for Transmission and Distribution Years 1981 through 2010 Shareholder-Owned Electric Utilities" of "Construction Expenditure Data" at www.eei.org/resourcesandmedia/industrydataanalysis/industrydata/Documents/Construction%20Expenditure%20Data.pdf.

Figure C-10. Annual Investment in Transmission Infrastructure by IOUs, 1997–2012[101]



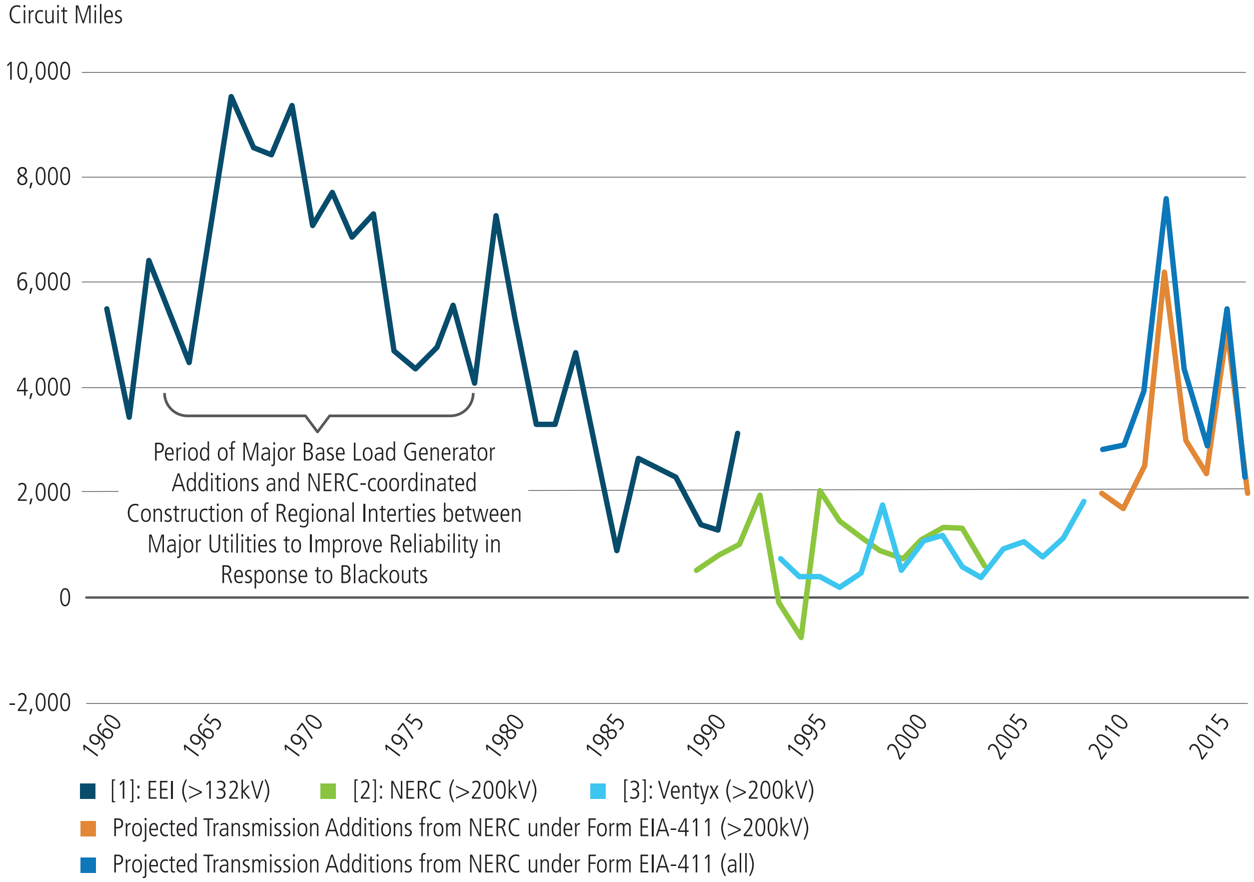
Spending on the various types of transmission infrastructure has been on the increase since the late 1990s.

Looking forward over the next several years, a high level of transmission investment is expected to replace aging infrastructure, maintain system reliability, facilitate competitive wholesale power markets, and aid regions in meeting their public policy objectives, such as GHG reduction and renewable energy goals.[102] Figure C-11 shows circuit-miles constructed from 1960 through 2010, with projections to 2017.[o] Note that Figure C-11's circuit-miles constructed have gone up and down in the time period shown in Figure C-10. The two figures are not contradictory, as Figure C-10 shows all types of transmission infrastructure spending, not just that which results in new transmission line-miles.

Over the time horizon considered by the Quadrennial Energy Review (QER), it is not clear how much future investment will be needed for new long-distance transmission versus other types of transmission investments. Factors include future electricity demand growth trends; the amount of transmission necessary to connect high-quality renewable energy resources to distant load centers; state and Federal incentives like the production tax credit; and the costs of competing generation and demand-side resources. For renewables, an additional variable is whether the costs and time of permitting of additional transmission facilities may lead to the development of wind or solar resources that are of lower quality but closer to load. Nevertheless, there are a number of long-distance interregional transmission lines now in various stages of market development.[103, 104]

[o] The figure shows only transmission circuit-miles constructed, including the large interties built in earlier decades as the bulk power grid became more interconnected and large amounts of new generation were added needing transmission. Transmission construction also includes substations and other equipment (such as smart grid technologies), which is reflected in Figure C-10. At first glance, differences between the two figures appear to be contradictory are due to the type of categories of transmission spending displayed.

Figure C-11. Historic and Projected Expansion of Transmission Circuit-Miles[105]



Looking forward over the next several years, a high level of transmission investment is expected to replace aging infrastructure, maintain system reliability, facilitate competitive wholesale power markets, and aid regions in meeting their public policy objectives, such as GHG reduction and renewable energy goals. Circuit-miles actually constructed in a year varies much more than total transmission infrastructure spending, which has had an upward trend since the late 1990s, as shown for IOUs in Figure C-10.

Continued construction of natural gas-fired generation also has implications for transmission infrastructure needs. Generally, new natural gas generation is being built closer to load centers and/or where existing pipelines and transmission lines are often found, thus providing a reduced need for new transmission versus if the new gas-fired generation was sited far from load. Local transmission upgrades may still be needed. Actual transmission needs for new gas-fired generation will depend on varying local and regional existing transmission topography.

Electricity Transmission Modeling Scenario Results

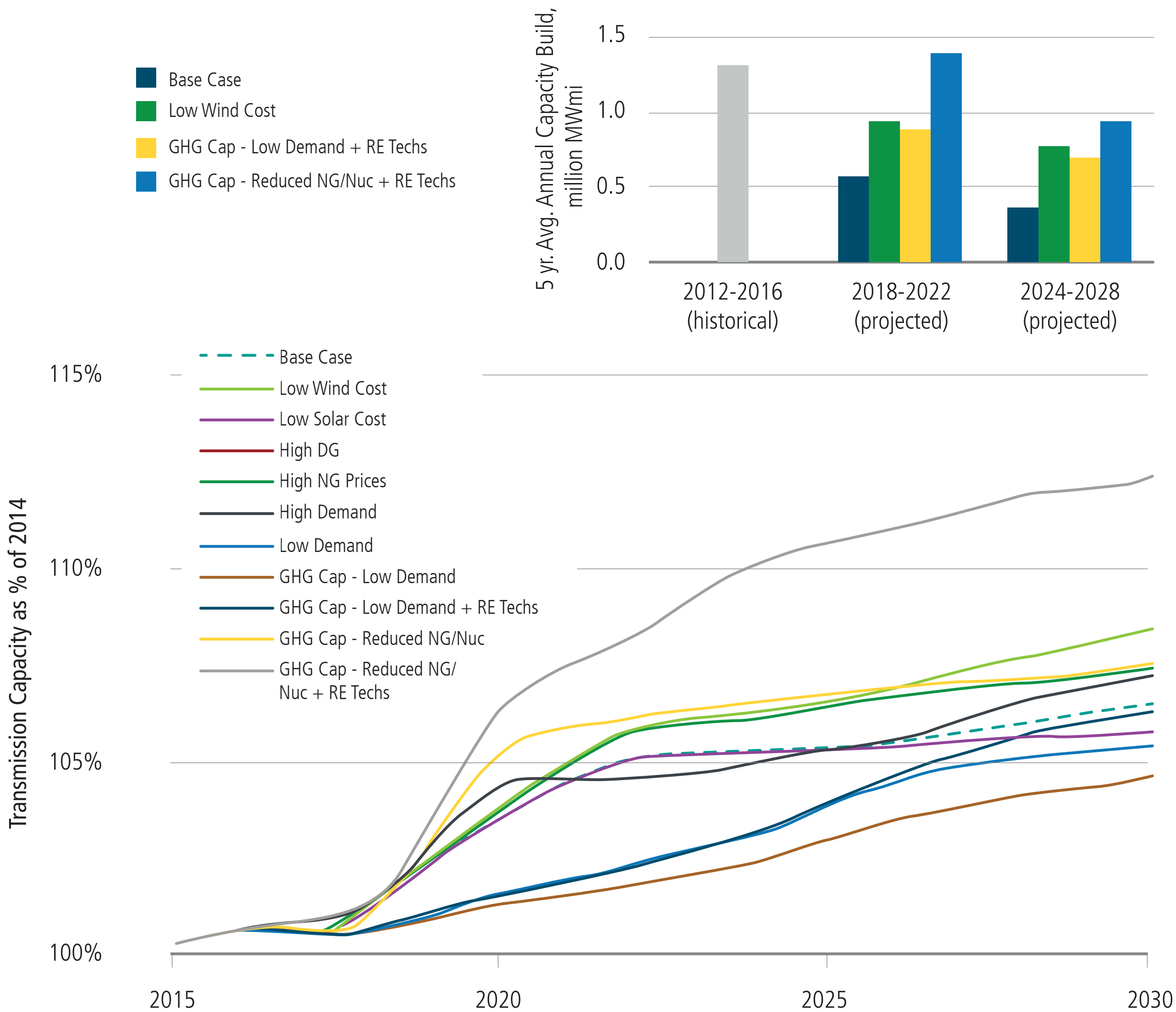
DOE analyses for the QER assessed the need for additional transmission capacity by 2030. Using the National Renewable Energy Laboratory's Regional Energy Deployment System (ReEDS) model and EIA's Annual Energy Outlook 2014 Reference case, the modeling indicates a need for additional transmission, representing roughly a 6 percent increase through 2030 in national capacity over 2014, in the base case.[p, q] This investment is somewhat evenly spread throughout regions of the United States. This rate under the base case scenario is relatively modest compared to historic increases.[106] This relatively low transmission infrastructure growth in the base case is matched by moderate turnover in and limited expansion of the generating fleet, both in the base case and in most of the QER scenarios. Low transmission growth in the modeled base case is attributable to excess capacity (and hence limited need for new construction), as well as to limited projected electricity demand growth (less than 1 percent per year in the base case).

In addition to the base case, 23 scenarios were analyzed to determine how factors like technology costs and changing demand might affect national transmission needs. Under nearly all scenarios analyzed for the QER, transmission needs through 2030 are roughly similar to those for the base case. Results of 10 illustrative scenarios representing the greatest differentiation among transmission results are shown in Figure C-12. The most differentiated scenario in this series is a bounding scenario that does not correspond to any current or proposed program and that examined the impact of a combined set of outlier assumptions: accelerated nuclear power plant retirements; 40 percent economy-wide GHG reductions in 2030, associated with a 60-percent reduction in carbon dioxide from the electricity sector; high natural gas prices; and low costs for renewable energy technologies. This outlier scenario suggests a dramatic shift in energy generation capacity where wind and solar make up nearly one-third of the energy mix in 2030. While this DOE QER analysis outlier scenario requires substantially more transmission than other scenarios in this analysis, the rate of modeled new transmission investment needed even for this case is well within the range of higher historical and planned near-term builds.

[p] Base case assumptions were aligned with the Annual Energy Outlook 2014 Reference case. Source: Energy Information Administration. "Annual Energy Outlook 2014." April 2014. www.eia.gov/forecasts/aeo/pdf/0383(2014).pdf. Accessed January 9, 2015.

[q] The model provides a rough insight into needs for new transmission. One limitation is that the model only builds new transmission along existing or proposed corridors. Local and regional reliability impacts of scenarios are thus not considered by the model. Such impacts could be significant depending on the specific local and regional existing transmission architecture. Any reliability issues would then need mitigation from new transmission, generation, and/or demand-side resources.

Figure C-12. Modeled National Transmission Expansion Needs Compared to Installed 2014 Capacity for the Annual Energy Outlook 2014 Reference Case (QER Base Case) and 10 Scenarios[107]



For the modeled system, decreases in wind costs and GHG limitations produced the greatest need for transmission relative to the base case; but even for those "high transmission" cases, 5-year transmission investment levels were not more than 5 percent greater than historical investment rates.

DOE ARRA-Funded Interconnection-Wide Studies

A review of three DOE-funded interconnection-wide studies, performed with American Recovery and Reinvestment Act of 2009 (ARRA) grants from 2012–2014, showed that scenarios combining high levels of end-use efficiency, demand response, and distributed generation can reduce the expected requirements for new transmission investment. One 20-year scenario modeled in the Western Interconnection resulted in a reduction of $10 billion in transmission capital costs, or 36 percent below the base case.[108]

More broadly, the DOE-funded interconnection-wide studies undertaken in the Eastern Interconnection, Western Interconnection, and the Electricity Reliability Council of Texas Interconnection (Texas), which used a range of scenarios and futures to create advisory-only 10-, 15-, and/or 20-year transmission plans, show results similar to those obtained by DOE analyses for the QER using the National Renewable Energy Laboratory's ReEDS model.

Interconnection-Wide Role of States in Transmission Planning

The United States has three electrical interconnections: the Western Interconnection, the Eastern Interconnection, and the Electricity Reliability Council of Texas Interconnection (ERCOT).

The Department of Energy (DOE) awarded funds in 2009–2010 to five interconnection-wide groups under the American Recovery and Reinvestment Act of 2009 (ARRA) for the purpose of conducting interconnection-wide transmission planning, together with related resource planning and associated studies and analyses. Some grantees ended their use of DOE ARRA funds in 2014, while others will end their ARRA funding in 2015.

One set of 2009 awards was made by DOE to state-based groups serving on an interconnection-wide basis. These state-based groups were the Western Governors Association (which included its subsidiary body, the Western Interstate Energy Board, in its work), the newly created Eastern Interconnection States Planning Council, and ERCOT. The state groups convened meetings for discussions among themselves and sponsored studies and analyses on a wide variety of electricity issues of common interest, not just limited to transmission planning.

A second set of 2009 awards went to three utility industry-based transmission planning organizations functioning on an interconnection-wide basis: the new Eastern Interconnection Planning Collaborative, the Western Electricity Coordinating Council, and ERCOT. These three groups used an open, transparent process over a several year period to create 10- and 20-year transmission plans under a range of stakeholder-driven future scenarios.

While the three interconnection-wide transmission plans were only illustrative and informational and not executable blue prints or roadmaps (only ERCOT's was used for actual investment purposes), they did illustrate what transmission needs would exist under a range of hypothetical technical and societal futures. One of the more significant conclusions reached in the process (by the Western Electricity Coordinating Council) is as follows:

> *"The expected future [2022 for the Western Interconnection], based on the existing transmission plus the Common Case Transmission Assumptions, appears to be adequate for the Western Interconnection to meet its load and [State] Renewable Portfolio Standard requirements over the 10-year time frame under 2022 Common Case assumptions."*

The various personal contacts, tools and processes created, and studies and analyses conducted over a wide geographic footprint have been recognized by the state, industry, and other participants as having great value.

Regional Transmission Needs

Transmission needs under the QER scenarios tend to be spread relatively evenly across regions. Patterns were fairly predictable in that, for example, low renewable technology costs produce higher transmission needs in the Southwest, and low wind costs produce greater transmission in the Great Lakes region.

Some evidence, such as the Texas experience discussion that follows, suggests that preemptively establishing a transmission line can serve to facilitate remote generation development today, such as those renewables that are remote from load. QER modeling shows that, under a national economic optimization, one form of lower-carbon generation, renewable energy—including wind and solar—can be expanded dramatically without much additional transmission investment beyond historical levels. However, the development of high-quality renewable resources (e.g., wind in the Midwest) might benefit from support for new transmission lines to load centers. The CREZ lines in Texas present one example where investment in new wind capacity followed construction of a new transmission capacity. However, securing customers who are willing to sign long-term electricity supply contracts is typically a prerequisite to obtaining investment in the transmission needed to access remote renewable energy resources. Several competing transmission line proposals in the South and West face challenges because they cannot yet secure power purchase agreements for the wind they would deliver.

Impact of Nuclear Retirements on Transmission

A separate modeling analysis of the transmission system impacts of additional early nuclear shutdowns, also done for the QER, showed limited need for large amounts of new transmission.[r] The analysis examined effects of closing up to one-third of the U.S. reactor fleet by 2020. The scenario was designed to facilitate examination of the potential impact on new transmission needs of an extreme level of nuclear closures; it was not intended to be predictive. Indeed, many factors—such as expectations of increasing electricity prices, or local policy decisions to maintain baseload generation—may provide sufficient revenue to keep at-risk reactors open. Additional early nuclear shutdowns also would have other implications, such as increased carbon dioxide emissions. Natural gas could be the dominant source for replacement and new electricity capacity, at least in the short-run time frame assessed.[109]

A ReEDS modeling simulation done for the QER of the same nuclear retirement scenario shows relatively little impact on the need for new major bulk transmission compared to the base case. Transmission requirements are initially higher than the base case, as nuclear plants close through 2020. Over that time frame, many plants are replaced by natural gas plants, especially where transmission is expensive, but in some regions, nuclear plant closures are replaced by building transmission and taking advantage of additional low-cost electricity generation capacity in other regions. After the accelerated closures end in 2020, transmission build-out tracks with the base case.[110]

While it is unlikely that a relatively large number of nuclear plant closures will create major additional transmission requirements, they do impact grid reliability at the local level—nuclear plants provide important grid services such as voltage support. Despite the small influence of significant nuclear retirements on national transmission needs, grid planners and operators, regulators, policymakers, and others will need to consider local reliability and climate impacts of any additional nuclear plant closures, as well as any potential impacts on distribution systems and some transmission lines at the regional level.

Planning the Future Transmission Network

After the historic build-out of new transmission in the 1950s and 1960s, the number of circuit-miles added slowly declined to a low point in the 1990s. Even when the amount of circuit-miles added was low, as previously discussed, actual investment in transmission continued to grow (see Figure C-10 and Figure C-11). The 2000s saw a significant increase in both planning and construction of new transmission miles and related infrastructure (see Figure C-11). A recent EIA publication documented a fivefold increase in new electricity transmission spending from 1997–2012.[111, 112] However, while that build-out continues today, recent years have seen a number of cancellations or delays of transmission projects for reasons ranging from the 2008 economic recession, to increased energy efficiency and demand response in load centers, to growth in distributed generation. Expanding shale gas resources also has led to natural gas power plants being built closer to load centers, thus reducing the need for electric transmission lines.[113] However, future additional use of natural gas generation may still require new electric transmission to be built, depending on adequacy of existing local and regional transmission architecture. In the context of expanding access to renewable energy, many discussions coalesce around the relative strengths and weaknesses of building long-distance, high-voltage electrical transmission lines from the high-quality resources to demand centers, as compared to relying on existing or shorter new transmission to connect demand with nearby, potentially lower-quality renewable or other resources.

[r] As with the overall QER modeling effort, this effort used ReEDs, which only builds new transmission along existing or proposed corridors and does not consider local and regional reliability impacts of scenarios.

Transmission projects can take more than a decade to reach operation and have high upfront capital costs. While a number of cost-recovery schemes are available, the incentive to build transmission rests on the fact that, relative to many other investments, transmission assets can provide long-term and stable returns—something that cannot be ensured elsewhere in a dynamic economy and technological environment. For example, American Electric Power—one of the Nation's largest electric utilities (and a large owner of both generation and transmission)—now has a strategy of not building new power plants, retiring power plants, and expanding its transmission network, which totals more than 39,000 circuit-miles that cross through 11 states, to provide reliable financial returns at a time when the industry's main sources of income (traditionally power generation) are flat.[114]

New builds (or "line upgrades") historically have come in two varieties: reliability upgrades and economic upgrades. Either can be proposed by incumbent transmission owners (typically electric utilities), or by newer market entrants that are transmission-only companies (sometimes called "transcos" or "merchant transmission"). When built to comply with reliability standards, a new line is called a "reliability upgrade" project. "Economic upgrades" connect new generation to load centers or reduce power system costs by more than the cost of the line. Such lines typically are built to ease or avoid congestion charges.[115] A transmission line may also be justified as a mix of these two categories. Due to the nature of electricity flows on a bulk power network, compartmentalizing the benefits between economic and reliability improvements can be difficult.[116]

The difficulty of linking thousands of power generation plants with transmission lines into one cohesive, reliable, and economic operating unit is just one example of the complexity of managing the grid. Because of this complexity, new transmission construction requires extensive technical and environmental planning. The nature of that planning process is partially defined by the ownership structure of the local utility or operator, regional customs, and now (increasingly) oversight by FERC. States also have jurisdiction over transmission, most notably over the siting of transmission lines on either private or state-owned land. FERC does have "backstop" transmission siting authority, which was conveyed to the commission by the Energy Policy Act of 2005; however, in part stemming from the Fourth Circuit decision noted earlier, FERC has never used this authority.

Electrical TS&D ownership comes in many forms. In 2014, the dominant model for transmission was still the vertically integrated IOU. However, groups of smaller public power utilities and rural electric cooperatives can also develop and own transmission through creation of a "joint action agency" or a "generation and transmission cooperative," respectively. The Federal Government can develop and own transmission projects through the Bonneville Power Administration, Western Area Power Administration, Tennessee Valley Authority, and Southwestern Power Administration. A more recent development is the emergence of independent and merchant transmission companies that develop and own transmission, but own no distribution or generation resources.[s] These companies often seek to build long-distance transmission lines that traverse more than one state.

All of these entities are subject to regulatory approval processes should they want to develop and site new transmission projects. Ownership has a direct effect on the regulatory regime applied to various transmission projects. For instance, publicly owned electric utilities (including the Federal Power Marketing Administrations and Tennessee Valley Authority) and almost all rural electric cooperatives generally are not subject to FERC's jurisdiction over transmission rates and planning—this means that they are not subject to FERC's planning and cost-allocation rules, so long as they act alone.

[s] Examples include American Transmission Company, International Transmission Company, Transmission Developers Inc., LS Power, Transource Energy, and Clean Line Energy Partners, among others.

Impact of FERC Order No. 1000 on Transmission Planning

FERC—under the Federal Power Act—regulates rates, terms, and conditions of service for transmission of electricity in interstate commerce. Courts have upheld that, based on the physics of the electric grid, this FERC authority applies to transmission facilities that do not cross a state boundary, if those facilities are part of the interstate transmission grid. One of FERC's most significant recent rulemakings is FERC Order No. 1000 (2011), which, among other actions, requires transmission providers subject to FERC jurisdiction to participate in a regional transmission planning process that meets certain minimum requirements.[117] For example, FERC Order No. 1000 requires those transmission providers to participate in a regional transmission planning process that has a regional cost-allocation method for new transmission facilities selected in the regional transmission plan for purposes of cost allocation. The method must satisfy six regional cost-allocation principles:

- Costs allocated must be "roughly commensurate" with estimated benefits
- Those who do not benefit from transmission do not have to pay for it
- Benefit-to-cost thresholds must not exclude projects with significant *net* benefits
- No allocation of costs outside a region unless the other region agrees
- Cost-allocation methods and identification of beneficiaries must be transparent
- Different allocation methods could apply to different types of transmission facilities.[118]

Transmission planning regions also are required to establish procedures for coordinating with neighboring planning regions, particularly to account for proposed projects that would be located in both regions. FERC Order No. 1000 also requires each pair of neighboring transmission planning regions to develop an interregional cost-allocation method for new interregional transmission facilities.

Renewable Energy and Transmission Planning

Renewable energy development can be inhibited if transmission is unavailable.[119] The most common problems are line congestion and lack of service to the most productive areas for wind, solar, and geothermal power—locations that are often far from load. Innovative approaches to planning and approving new transmission for renewables began to emerge in 2005 with considerable regional variation due to renewable resource endowments and local institutional arrangements. As noted previously, FERC Order No. 1000 requires transmission providers subject to FERC jurisdiction to participate in a regional transmission planning process that provides for consideration of transmission needs driven by public policy requirements, which may include enacted state policies such as state-mandated renewable energy goals. Transmission planning often involves decisions by more than one jurisdictional authority, requiring agreement on how to allocate costs and the value of benefits. Studies by DOE national laboratories[120, 121, 122] corroborate the potential savings: strategically sited long-distance transmission, as one element of a comprehensive renewable energy plan, can reduce capital costs, improve output per dollar invested, and result in greater customer savings.

Several Western Interconnection states—individually, as well as jointly with all of their fellow Western states through the Western Governors' Association—have studied renewable energy zones with the aim of consolidating transmission development. This work has fed into long-term transmission planning conducted by the Western Electricity Coordinating Council, the California ISO, and individual utilities.[123, 124] California ISO's 2013 transmission plan, for example, identifies 41 projects at an estimated cost of $1.75 billion that would maintain reliability, meet the state's renewable energy mandate, and deliver other economic benefits.

Transmission planning for large-scale renewable expansion in the Eastern Interconnection includes work done by the Southwest Power Pool and Midcontinent ISO, whose territories include some of the most productive wind areas in the country. In 2010, Midcontinent ISO identified a number of wind development zones in the northern Great Plains that have since guided transmission planning. It estimates that its plans had saved customers more than $1.2 billion in projected annual costs, while at the same time enabling 41 terawatt-hours of wind energy per year.[125] Southwest Power Pool's most recent 20-year transmission plan identifies $845 million in projects that would provide an estimated $1.5 billion in benefits and would enable up to 9,000 MW of wind development.[126]

Today, transmission planning to integrate renewables is seldom a stand-alone exercise. Many of the largest and more recent plans simultaneously address renewable energy integration in conjunction with other planning objectives, such as reliability, congestion, and connecting other new generation. DOE awarded $80 million in ARRA funding for the purpose of facilitating the development of regional transmission plans, building on foundational work done in the Western, Eastern, and Texas Interconnections. Each interconnection-wide effort had a technical component—led by that interconnection's transmission grid planners and operators—that examined (along with other generation and demand-side issues and scenarios) reliable delivery of least-cost renewables to major demand centers, and a policy component examining issues that could be facilitated by regulatory coordination. In addition to the detailed engineering studies, plans, and white papers, the interconnection-wide groups have gone beyond their original ARRA funding and continue to serve as venues for regulatory and technical collaboration.[t] The Administration has put a number of measures in place to support the development of transmission lines for renewable energy that are summarized in the main QER report.

Distribution

Role and Physical Characteristics of System

Distribution is the delivery of power from the transmission system to the end users of electricity. There are about 6.3 million miles of distribution lines.[127] Distribution substations connect to the transmission system and lower the transmission voltage to medium voltage. This medium-voltage power is carried on primary distribution lines, and after distribution transformers again lower the voltage, secondary distribution lines carry the power to customers who are connected to the secondary lines (larger industrial customers may be connected directly at the primary distribution level). The poles supporting distribution lines, meters measuring usage, and related support systems are also considered to be part of the distribution system. EEI estimates that $275 billion has been invested in the United States' distribution system by its member utilities since 2000.[128] EEI's most recent survey of T&D spending by member utilities gave $20.8 billion for distribution in 2013—a 3.5-percent increase over 2012's $20.1 billion. EEI stated that "[t]he increased distribution level capital expenditures were largely linked to storm hardening and improved system reliability, including undergrounding infrastructure."[129]

[t] Some of the interconnection-wide groups (i.e., the Electric Reliability Council of Texas, the Western Electricity Coordinating Council, and the Western Governors' Association and its related Western Interstate Energy Board) existed before ARRA funding. These groups used the ARRA funding to greatly expand and modernize their efforts with the latest tools and information, while the Eastern Interconnection Planning Collaborative and Eastern Interconnection States Planning Council were created as a result of the ARRA funding.

Physical Distribution System Vulnerabilities

Aging Equipment

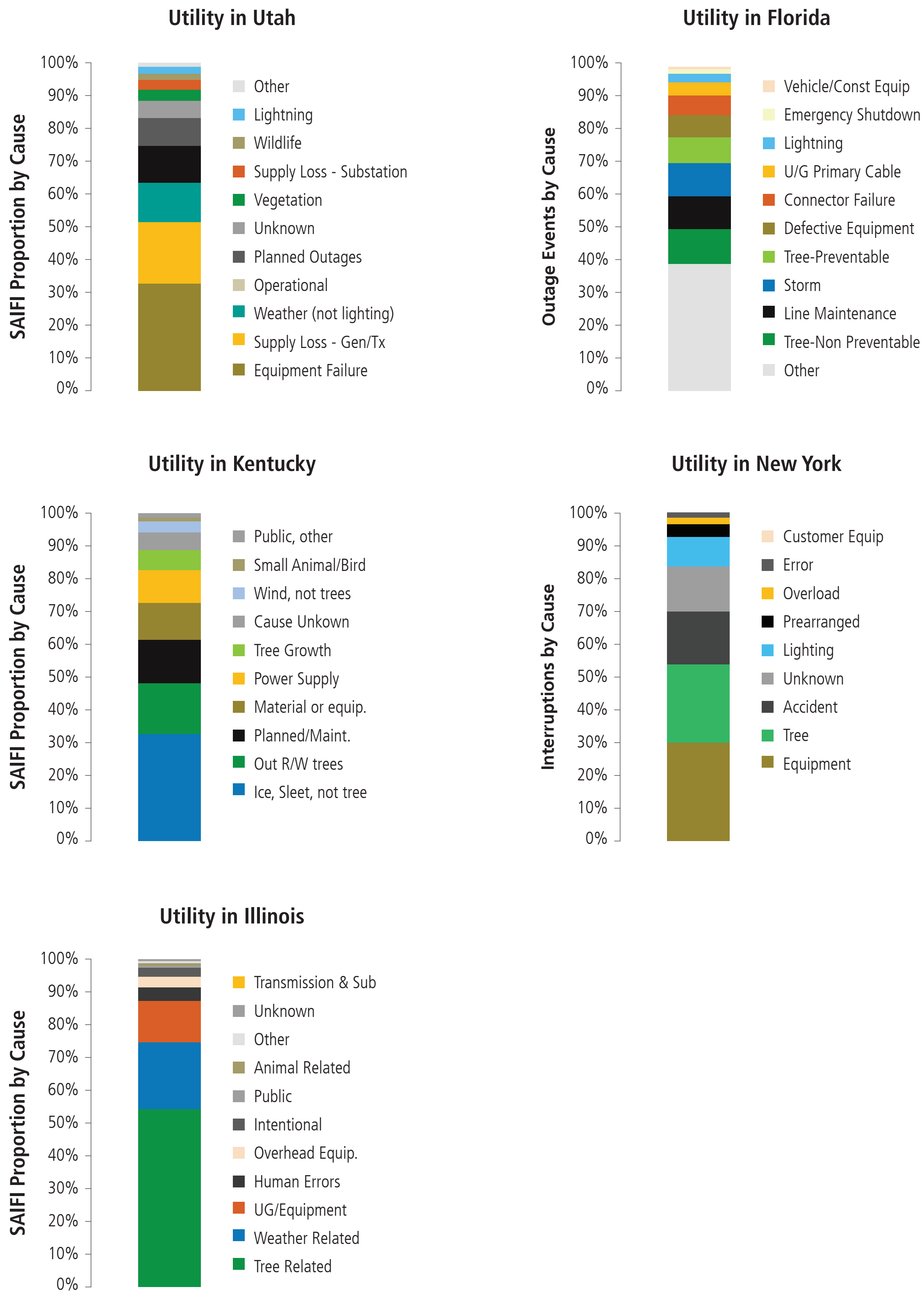
A survey of more than 500 utility professionals across the country revealed that "old infrastructure" is the most common concern.[130] The American Society of Civil Engineers in 2013 gave the Nation's energy infrastructure a grade of D+, citing an aging electrical grid and distribution facilities that have resulted in an increasing number of power disruptions.[131] However, concern over age is not universally shared,[132] with the counterpoint being that equipment can be and has been continually updated and maintained until economics indicate that replacement is more prudent.

Disturbances

As with the transmission system, the distribution system experiences a wide variety of natural disturbances, such as lightning, wind, ice, animals, and trees. Other disturbances include human-related contact, damage to distribution structures, and equipment failure. As opposed to transmission, where network redundancy virtually eliminates outages from a single failure, distribution outages are more likely to lead to customer interruptions than are transmission outages. While efforts to collect comprehensive, comparable nationwide data are still under development, initial reviews of reported metrics shows wide variations in outage rates and causes.

The causes for distribution outages can vary significantly depending on the location of the circuit and the time of year. For example, a single utility may experience predominantly tree-related outages on one circuit and wind-related outages on a neighboring circuit.[133] Lightning may be a consistent cause during some months but not others.[134] Figure C-13 shows a sampling of reported end-user reliability metrics from utilities across the country. These graphs illustrate both the diversity of outage causes and the differences in reporting definitions. While some analyses have found a statistically significant trend in distribution reliability over time, the magnitude of this trend is small compared to year-to-year changes.[135] The directionality of the trend can also change depending on the window selected for the analysis.[136]

Figure C-13. Sample of Reported Causes of Outages to End Users from Selected Distribution Utilities[137]



This figure shows a sampling of reported end-user metrics, such as the System Average Interruption Frequency Index (SAIFI), from various utilities illustrating both the diversity of outage causes and the differences in reporting definitions. Definitions of outage causes vary from utility to utility; hence, the keys are slightly different for each state utility bar. The data may not include the entire utility service territory and does not cover the same time period.

Distribution reliability is regulated by state utility commissions, or by locally appointed or elected boards for cooperatively owned and publicly owned utilities not regulated by state utility commissions. Most, but not all, states require their utilities to report customer interruption metrics.[138] Cause categories can be defined by the state commission or the utility, with little uniformity across states. EIA does collect information on outage statistics, but does not record causes.[139] The Institute of Electrical and Electronics Engineers (IEEE) is standardizing calculation methods and definitions for distribution statistics through standard IEEE 1366-2003/2012, as well as undertaking a voluntary benchmarking effort to improve the quality of distribution reliability data.[140] The lack of uniform national data prevents more sophisticated analysis of macro trends in distribution reliability.

Distribution utilities have pursued a wide variety of options to reduce system vulnerabilities. Anecdotally, distribution utilities appear to be implementing distribution automation, fault analysis, and outage management systems to identify and correct problems.[141] These systems can then be used as the basis for additional corrective programs, such as enhanced vegetation management or proactive maintenance. Many utilities also have pursued physical hardening investments, such as placing circuits underground (at additional cost). For example, utilities and utility commissions in the District of Columbia, Maryland, New Jersey, and New York have evaluated and selectively approved resiliency investments following recent major storms.[142]

Current resource adequacy requirements at the bulk power level are usually based on "1-day-in-10-year" loss of load probability standard. For the distribution system, however, it is difficult to pin down specific measures of reserve reliability, and assessing the appropriate level of reliability and investment requires nuanced analysis. Utilities often compare the cost of incremental investments in reliability against historic response of their customers to outages and benchmark against other utilities. Recently, some utilities that have sought to make major investments in distribution reliability and resiliency have been asked by regulators to estimate economic benefit measures of the avoided customer outage costs. Some economists have applied the "value of lost load" concept as a means of quantifying benefits.

Using value of lost load to measure benefits is still being tested; as a result, there currently is no common industry standard. Most value of lost load assessments use customer surveys to estimate the value that customers place on reliability ("willingness to pay"). Better information on costs and benefits of particular hardening actions, as well as better metrics of resilience, would greatly improve utility and state-level decision making on hardening investments.

Cost Recovery in the Distribution Network

Cost recovery at the distribution level is regulated by individual states for the distribution utilities under their jurisdiction; locally elected or appointed boards do the same for most cooperatively owned and publicly owned electric utilities. Operational expenses typically are recovered in base rates (and are approved through a regulatory review). Capital expenditures related to the distribution plant also are included in a utility's rate base and depreciated over the asset's useful life. IOUs earn an allowable rate of return on capital expenditures; rates include standard depreciation expenses.

The most common practice by which regulated utilities recover costs is through a general rate case, where a utility seeks to change rates based on changes in operational expenses or new plant additions. If the utility incurs costs that are unanticipated in the design of rates, then it must defer those costs for recovery after it has another rate case, or pursue an alternative regulatory path for rate recovery. Regulators and utilities have developed alternative approaches to allow cost recovery for unanticipated costs, including cost deferral, rate adjustment mechanisms, formula rates, and storm reserve accounts.

The increasing economic losses from storms have motivated changes to regulatory frameworks to incentivize improvements in reliability and resiliency to storm events. These changes have taken several forms, including performance-based formula rates, with annual reconciliation of resilience capital expenditures (for example, in Illinois); incorporating anticipated resilience expenditures in rates before the investment is made (for example, in Maryland); and performance standards for emergency preparation and restoration of utility service that are accompanied by financial penalties for non-compliance (for example, in Massachusetts).[143]

New Technologies and Services in TS&D

A revolution in information and communication technology is changing the nature of the power system. While many of these new technologies are "behind-the-meter," involving end-use management or generation on the consumers' premises, smart grid technology also enables sizable improvements in distribution and transmission automation. These technologies monitor, protect, and automatically optimize the operation of its interconnected elements, including central and distributed generation; T&D systems; commercial and industrial users; buildings; energy storage; electric vehicles; and thermostats, appliances, and consumer devices.[144] Smart grid technologies include a host of new and redesigned technologies, such as phasor measurement units (PMUs) or advanced metering infrastructure (AMI), that provide benefits such as increased reliability, flexibility, and resiliency.[145, 146, 147] As with information technology that continues to expand outside of the utility industry, use of more information technologies in the electric system (i.e., the smart grid) do raise cybersecurity and privacy concerns that need addressing.[148]

Many are integrating at least some of these new products and services into the grid, with more work to be done on deployment, as the products, services, and technologies evolve and become increasingly cost effective.[149] Integrating all the new pieces into the existing grid can be a technical and economic challenge and opportunity that will vary depending on local and regional circumstances.

Phasor Measurement Units

PMUs are devices that enable a synchronized picture of power system conditions.[u] Prior to the advent of PMUs, there could be a lag of up to several minutes in assessing system data—a long time delay when trying to take a coherent snapshot. PMUs monitor the system multiple times a second and provide synchronized time stamps using Global Positioning System information. Better real-time information through PMUs offers system operators the best strategy for managing reliability and operating the grid closer to the operating margins, and it may reduce the need for new investments in transmission infrastructure.[150, 151] PMUs allow for dynamic system analysis and control, enhancing the integration of variable renewables. PMU deployment in the United States has increased significantly due to investments made under ARRA, with the number of networked PMUs growing from 140 in 2009 to nearly 1,700 by 2013.[152]

Dynamic Line Rating Systems

Currently, transmission system operators rely on fixed ratings of transmission lines that are established to maintain reliability during worst-case weather conditions (e.g., hot, sunny weather). Under most conditions, such as lower temperatures or higher wind speeds, transmission lines can be safely operated at higher usage levels. Dynamic line rating systems help operators identify available real-time capacity and have been shown to increase transmission line capacity by 10–15 percent. Dynamic line rating systems can also help facilitate the integration of wind generation into the transmission system.[153]

[u] PMUs operate by the simultaneous measurement and comparison of an important electrical property of large-scale alternating current transmission networks known as "phasor angles"—thus the name "phasor measurement units." Only today's very fast computing and communications technologies now allow such real-time grid monitoring to occur, thus providing valuable real-time early warning of potential grid problems over very large geographic regions when the technology is fully deployed and related tools to use the information are implemented.

Distribution Automation

For distribution systems, distribution automation projects funded under ARRA have reported improvements in system average interruption frequency index (a metric of distribution reliability) of 11–49 percent. Automated feeder switching reduces the frequency of outages, customers affected, and minutes interrupted. Fault Detection, Isolation and Service Restoration systems can increase circuit loading limits by 50 percent without a decrease in reliability, sometimes removing the need to construct an additional circuit.[154] Rural areas with long feeders and low population densities may especially benefit from distribution automation that can identify locations of outages.

Advanced Metering Infrastructure

AMI systems combine two-way communications capability, new information-based technologies that enable data collection and operational control, and "smart meters" installed at the point the distribution system connects to the customers' systems. The two-way communication technology allows the company to send and receive data at regular, sub-hourly intervals.

At its most basic level, AMI is used to reduce labor, truck, fuel, and data collection operational costs associated with manual meter reading. When appropriately equipped, smart meters also enable remote connect and disconnect using the distribution system, reducing operating costs. During outages, smart meters help to more quickly locate the outage and those that are remotely reconnected, which both reduce distribution outage time.

AMI can be enable customers to access information on their energy use in real time or near-real time. Some customers who have chosen AMI-enabled variable rates have achieved energy consumption reductions exceeding 30 percent during short periods.[155] Such demand response provides system operators multiple benefits, including reduced demand (which is particularly valuable during peaks where generation costs are rising) and potentially increased system flexibility. AMI can facilitate new pricing schemes, such as time-of-use or other forms of time-varying pricing, which has been demonstrated to reduce peak demand in excess of 30 percent. However, using AMI for customer-focused uses is in the early stages, with most benefits to date from AMI being in improving utility operations.

Distributed Generation and Two-Way Power Flows

Distributed generation systems include photovoltaic systems, small wind, fuel cells, reciprocating internal combustion engines (diesel, hydrogen, natural gas, propane, gasoline, etc., as fuel), combined heat and power, biomass, geothermal, concentrating solar power, Stirling engines, small hydro, and other technologies. Distributed generation systems can provide a number of benefits, including increased electric system reliability; reduction of peak power requirements; provision of ancillary services, including reactive power; improvements in power quality; reductions in land-use effects and rights-of-way acquisition costs; and reduction in vulnerability to terrorism and improvements in infrastructure resilience.[156] Microgrids, deployed when they make economic sense for their owners, can also bring both regional and local benefits, including reactive power and voltage control, reserve power, and black start capability.[v] In addition, large-scale microgrids can provide frequency control reserves and reduce or offset substation and feeder investments.[157]

[v] Black starts are accomplished when certain types of power plants are down and an area-wide blackout prevents their restart, which would normally occur by drawing power from the grid. To provide a black start, some power stations have small diesel generators, normally called the black start diesel generators, which can be used to start larger generators (of several megawatts capacity), which in turn can be used to start the main power station generators at the large power plant.

Most distribution systems have accommodated the modest number of distributed systems connected to date, but some utilities (e.g., in California, and Hawaii) face operational issues associated with significantly higher levels of distributed photovoltaic generation behind meters.[w]

Challenges and Opportunities from New Technologies and Services

While deployment of advanced smart grid-type technologies, as well as various types of distributed energy resources, can lead to system benefits, they face a number of challenges, including those related to interoperability, security, privacy, and costs.

Interoperability

Interoperability is the ability of systems and devices to work together easily and effectively. Interoperability creates the seamless, end-to-end connectivity of hardware and software—from the customers' appliances, all the way through the T&D system, to the power source. If successful, it enhances the coordination of energy flows with real-time flows of information and analysis. Not only does a lack of interoperability hinder further deployment of the smart grid, enhanced interoperability could lead to estimated savings for the electricity industry from about $3.5 billion to about $10 billion per year.[158]

Security

While smart grid technology can make the electric system more robust, it has the potential to make the grid more prone to cyber threats. The more extensive the interconnections and interdependencies, the greater the potential damage from cyber threats. While the QER does not extensively review the impacts of cyber activity, a variety of other government-wide efforts, led by the Department of Homeland Security, are developing policy recommendations and in-depth analysis on this issue. While cyber threats may increase risk, and various elements of new smart grid technologies can impose costs and operational constraints, grid reliability can be improved through smart grid applications.

Costs

Emerging technologies pose new challenges. Often, their costs are uncertain or higher than the systems they replace, causing concern about the impact on rates. However, many new technologies also have the potential to provide more or better functionality (e.g., more reliable or cleaner electricity) than older technologies and therefore more benefits.

Valuing New Services and Technologies

The identification of both the costs and benefits of new technologies is fundamental to identifying efficient investments and for maintaining reliability and affordability of the rapidly evolving electricity system. New methods and tools would be beneficial and are needed. Some are now available, such as an integrated grid cost-benefit framework tool released in February 2015 by the Electric Power Research Institute.[159]

[w] There are several different measures of "penetration." "Meter penetration" is a measure of how many customers, or meters, have distributed generation on a circuit or line section (defined as total meters with distributed generation divided by total meters on circuit or line section). "Capacity penetration" is common, but a less useful metric; it is defined as the total distributed generation capacity divided by the total circuit capacity. While there is no formulaic way to describe the impact of distributed generation penetration, it is recognized by industry experts that a small number of distributed generation on a circuit likely will cause no discernible problems, while larger numbers and larger sizes of distributed generation, at longer distances from the substation, will create numerous challenges in a non-linear manner.

Net Metering

Net metering is a system for paying for generation located on customer facilities. Currently, 43 states have Net Energy Metering (NEM) programs that allow the sale of customer-generated power back to the utility under terms determined by regulators. The most common type of NEM customer today owns or leases a rooftop photovoltaic system; however, current regulations often also apply to other distributed energy technologies, such as gas-fired turbines and combined heat and power. The utility typically pays the NEM customer at retail rates for electricity sold to the grid, with limits on the total sales over a specified period (typically 1 year).

With rapid solar photovoltaic market penetration, controversies among utilities, consumer groups, solar businesses, and other stakeholders have arisen in several states, placing pressure on legislators and regulators to understand conflicting positions and analyses supporting them. Some argue that NEM customers are providing benefits to the system, which justify NEM retail rates, and, in some cases, additional benefits for which they are not compensated. They also argue that NEM customers are providing environmental, jobs, and other local public benefits that should be recognized. Some raise concerns about NEM customers benefiting from grid services without paying the full cost of such services. Some further note that if NEM customers fail to pay for the full cost of the grid services, non-NEM customers are cross-subsidizing the NEM customers. The resolution of these issues must address the potential for stranded assets on the consumer and the utility, as well as the value of services provided by both.

Operational Issues of Distributed Generation

As penetration levels of distributed generation rise, additional measures can be required in order to keep the local grid safe and reliable.[160] Challenges related to the interconnection of distributed generation can be addressed and mitigated, but those mitigation measures often come with a cost.[161]

Institutional Vulnerabilities/Challenges—Utility Business Model for Distribution Operations

Significant changes at the distribution level in planning, operations, rate structures, and regulatory oversight models are likely to occur if distributed generation continues to grow aggressively, as has occurred in some regions. Besides distributed generation, the provision of energy efficiency services and the cost of resilience upgrades will also impact the utility business model at the distribution level.

Integrating new services and technologies into the grid of the future can challenge the traditional utility business model by reducing revenues, asset bases, and returns on investment. Technology that transforms the role of the customer is one factor driving utility capital requirements, along with the need to reduce carbon emissions and increase resilience—all at a time of declining rates in electricity demand growth. From a consumer standpoint, the technological transformation offers new services (including local benefits, as well as a potential revenue stream for the sale of excess power and demand management). The system too can benefit, with increased reliability and resilience, as well as lower overall operating costs for power generation. However, with new options, it is likely that new providers—as well as changes in the utility revenue streams—will occur. These shifts have given rise to an increasing concern about how to define the role of the utility and how to compensate the utility for providing service.

Background on Relevant Electric Sector Structure

Table C-3 provides an overview and a series of examples of the types of entities—characterized by ownership and scope—that make up the current electric utility landscape.

Table C-3. Taxonomy of Entities within the Electric Utility Sector, with Examples[162]

	State-Regulated IOUs	Cooperatively Owned	Publicly Owned	Federally Owned	Merchant
Vertically Integrated (T,D,G)*	Oklahoma Gas & Electric	None	Los Angeles Dept. of Water & Power	None	None
Transmission and Distribution	Pepco	Southern Maryland Electric COOP (SMECO)	Clallam County Public Utility District	None	None
Generation and Transmission	None	Basin Electric G&T	New York Power Authority	Tennessee Valley Authority	LS Power
Generation and Distribution	DTE Energy; Consumers Energy	Fox Island (ME) Electric	Lansing (MI) Board of Water & Light	None	NRG
Transmission	None	Upper Missouri Power Cooperative	Transmission Agency of Northern Calif.	Western Area Power Administration, Bonneville Power Administration Southwestern Power Administration	ITC; Hudson Transmission; Transource Energy; Clean Lines Energy Partners
Distribution	Mt. Carmel Public Utility Co.	Kenergy	Nashville Electric Service	None	None
Generation	None	Oglethorpe Power Corporation	Wyoming Municipal Power Agency	Bureau of Reclamation	Calpine; BP Energy; Tenaska;

* (T,D,G= Transmission, Distribution, and Generation)

The diversity of ownership structures and asset sectors can be considered a strength of the United States, as it gives us one of the world's most reliable, affordable, and increasingly clean ways of providing the basic need of electricity, as well as results in innovative approaches. Such diversity often precludes one-size-fits-all policies.

For decades, the traditional large utility was vertically integrated. It sought to increase demand from customers and to build generation, transmission, and distribution infrastructure to serve that demand. For much of the industry's early history, the provision of electric service exhibited natural monopoly characteristics—that is, it was less costly for a single entity to serve load in a particular area than multiple entities. The expansion and consolidation of utilities into larger utilities and, ultimately—in some parts of the United States—utilities joining power pools and ISOs/RTOs was driven by economies in the provision of service.

The diversity of entities that own and operate the grid leads to a complex set of motivations and decision drivers. The reliable operation of the grid is a testament to the harmonization of these different interests. Essentially, there are five different ownership types: (1) investor owned; (2) cooperatively owned, owned by their member customers; (3) publicly owned (i.e., municipal, state, utility districts, irrigation districts, and joint action agencies); (4) Federally owned; and (5) merchant companies that are competitive entities in generation, transmission, or retail supply. Each ownership pattern engenders different interests in performance of service, investment, and market structure.

Regulated entities that earn profit based upon a return on invested capital are motivated to provide service through capital-intensive options and lack a strong incentive (absent explicit requirements or incentives) to invest in energy efficiency or other practices that do not involve electricity sales or large capital expenditures. Public power and cooperative utilities are motivated to keep customers' bills down. Merchant generators, whose profits are the residual revenues after expenses are paid, are motivated to maximize returns in the context of FERC-regulated wholesale markets. Federal Power Marketing Administrations (Bonneville, Western, Southwestern, and Southeastern Power Administrations) and Tennessee Valley Authority must follow the dictates of their enabling Federal laws in the way they provide services to customers. They are service-oriented public bodies that do not seek to make a profit, but they must cover their costs and multi-purpose mandates of their enabling laws.

The RTOs/ISOs are organizations, operated similarly to nonprofits, that provide transmission and related wholesale bulk power-level services in interstate commerce. RTOs/ISOs do not own transmission facilities, but rather provide service over transmission facilities that are owned by their member utilities and for which those utilities have transferred operational control to the RTO/ISO. RTOs/ISOs also administer competitive centralized wholesale markets for electricity (and, in some regions, generation capacity and some ancillary services) in their footprints. RTOs/ISOs have no financial interest in the resulting market prices, but must ensure such prices result from adherence to tariff mechanisms that have been approved by FERC as just and reasonable and not unduly discriminatory or preferential. Among other things, RTOs/ISOs also engage in region-wide transmission planning.

As the distribution system evolves with increased distributed generation, responsive demand, and two-way power flows, industry and regulators have begun to consider whether a distribution-level analog to the ISO (a Distribution System Operator) is needed to help coordinate the increasing complexity of distribution-level operations. On the other hand, poor economies of scale for the many small or smaller distribution utilities, as compared to the rather large ISOs/RTOs, can argue against a separate Distribution System Operator solution.

The structure of the electric utility industry has important implications for the resolution of four major issues now facing the industry: (1) conditions under which utilities provide energy efficiency services, (2) the relationship of the utilities to the provision of distributed energy resources, (3) the ability of electric utilities to recover costs of improving resilience, and (4) the structure of the distribution utility.

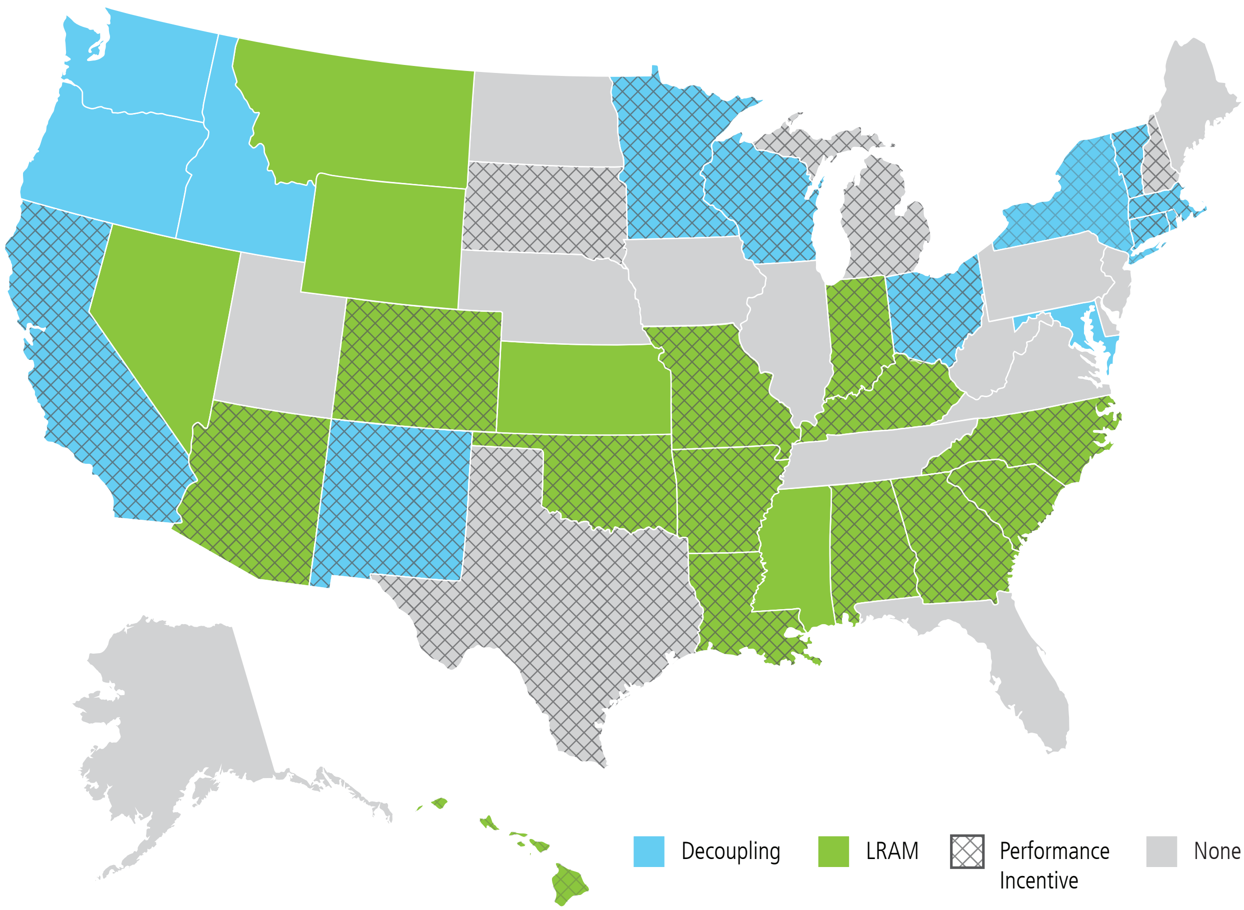
Two common themes apply to all four issues—how the element will be priced and recovered in rates and clarification of the role of the utility. The discussion that follows on energy efficiency measurement and service valuation offers areas where additional analysis and tools can help guide this evolution.

Energy Efficiency

Under the traditional IOU regulatory model, IOUs benefit most directly from an increasing asset base (which can occur as a result of load growth), rather than from reducing demand through energy efficiency. Recognizing that in many cases energy efficiency is the least-cost method of serving customers' electric service requirements or achieving emission reduction targets, the state regulatory community has sought to overcome financial disincentives for utility energy efficiency programs financed by ratepayers. Cost recovery, addressing what is known as the "throughput incentive," and performance incentives are the three foundations for implementing effective ratepayer-funded energy efficiency. These are commonly implemented through three major regulatory approaches: decoupling, lost revenue adjustment mechanisms, and a broad set of measures to allow performance incentives (see Figure C-14).

The role of the utility in providing energy efficiency services varies, in part as a function of whether IOUs are permitted to own the equipment and provide the service for implementing energy efficiency, or—as in some states—whether revenues used for energy efficiency services are provided through customer funding of state-run programs. In one case, the utility might see energy efficiency as a business opportunity—in the other, as a pass through for third parties. This incentive problem can be less of an issue for publicly owned utilities and cooperatively owned utilities, which have a broader mandate to provide different services and are both not-for-profit organizations. These utilities are primarily concerned about their ability to recover costs and provide the lowest-cost service to their customers; because both entities are directly responsible for the design of their rates, they are free to design rates that enable cost recovery. However, costs sunk into capital assets—such as generation, transmission, or distribution—may still pose barriers to energy efficiency for public power and rural electric cooperatives, as those costs must be recovered.

Figure C-14. State Regulatory Approaches Encouraging Ratepayer-Funded Energy Efficiency to Address Utility Business Model Concerns[163]



Thirty-six states have adopted one of three regulatory approaches to promote utility investment in energy efficiency: decoupling, lost-revenue adjustment mechanisms (LRAM), or performance incentives.

The evaluation, measurement, and verification of energy efficiency savings will become increasingly important as efficiency becomes more used as a utility resource. Many entities have made progress toward standardizing the evaluation of energy efficiency. These methods can help regulators understand the opportunities energy efficiency creates for infrastructure avoidance.

Ratepayer-funded efficiency programs run by utilities and third parties, as well as energy service company efficiency programs and other non-utility efficiency programs, have achieved significant energy savings over the last three decades.[164, 165] These programs were developed in different ways across the country, and there are different approaches used for measuring and verifying savings. While inconsistencies can complicate efforts to compare measured savings across jurisdictions, a number of important standardization efforts have emerged in recent years at the state and regional levels that have started to address these issues. These include efforts led by the Northwest Regional Technical Forum and the Northeast Energy Efficiency Partnership that include development of regional databases of energy savings.[166, 167] Building on this momentum, DOE's voluntary Uniform Methods Project for Determining Energy Efficiency Program Savings has connected policy stakeholders and technical experts over the last 3 years.

Resilience

Essentially, investment to improve resilience is an insurance policy for ratepayers. The purpose is to minimize damage, not to expand services. The daily use by customers will not be affected by resilience investments, but these investments potentially are costly. Utilities of all sorts, including investor owned, publicly owned, and cooperatively owned, and their regulators evaluate how to make systems more resilient without overly burdening ratepayers.

Ratepayers can be made better off by reducing the cost of financing resilience investments. There are a variety of vehicles for doing so. For example, Washington, D.C., is pursuing undergrounding of parts of its distribution system to withstand extreme storms through a variety of ratepayer and non-ratepayer city financing. Capital costs themselves are reduced through a variety of financial instruments, including securitization—where a dedicated revenue stream is developed to pay for the asset, thereby improving the credit quality of the debt.

Role of the Distribution Utility

The introduction of new technologies and the transformation of the role of the customer have a significant impact on the role of the distribution utility. The magnitude of information flow will increase dramatically, with a need to coordinate both the role of customers and distribution-level control devices and practices (such as conservation voltage reduction). As distribution is the interface between the customer and the bulk electric system, the distribution utility could have a significant role in repackaging and transmitting the information flowing between the two. The New York Public Service Commission issued "Reforming the Energy Vision"—a proposal that contemplates a role for a new Distribution System Operator entity that would coordinate the transactive loads of customers and act as the interface with the New York ISO. Currently, the California Public Utilities Commission is investigating the role of the utility in the development and ownership of electric vehicle charging stations. There are many models of utility involvement in energy efficiency and distributed energy resources. While there is no single model for the future utility (or non-utility entities that provide similar service), it is likely that successful models will need to incorporate transactive loads as new technologies become available, provide resilience, and be partners in reducing GHGs while redefining their compensation models.

Transactive Energy and the Future of the Grid

Transactive energy refers to the concept of using all of the intelligent devices in the electric grid, from the consumer level to the bulk power level, and giving them price signals that vary with time. The desired result of dissemination of price signal information is a more optimal allocation of resources for the benefit of all. In a sense, traditional price-responsive demand-side programs that have been used by industrial, commercial, and some residential customers can be said to be transactive energy. However, the newer form of transactive energy promises to engage the demand side of electricity use in new ways that have become available due to the emergence of a plethora of information technology-enabled devices—commonly called the smart grid. Sometimes this concept is more simply described as "prices to devices."[x]

The roots of the transactive energy concept can be traced to a Department of Energy-funded pilot program started in 2006 in Washington State's Olympic Peninsula by Pacific Northwest National Laboratory. This pilot program allowed electricity customers along a distribution feeder to participate in an artificial electricity market run by Pacific Northwest National Laboratory computers that included both load (such as appliances outfitted with communication devices) and generation.[y] Market forces were shown to be able to generate a time-changing price signal that would control loads during peak times to delay an upgrade to the overloaded distribution feeder.

A simple explanation to a concept that can be complex to describe is, "[i]t's basically leveraging the communication and the smart (functions) on some of the devices, the embedded microprocessors on the devices, to enable these things. Like your hot water heater (being) able to communicate to a smart meter which is getting the price signal that's flowing down through the system. You might say, for the next five minutes, 'I really don't need my water that hot and I could earn a little money if I could back it off by a couple of degrees.' So it's leveraging that communication and local decision making in ways we could never do before until we had some of these devices."[z]

Outside of pilot programs, transactive energy, in its advanced form, is still just a concept. Mass adoption of transactive energy would require a number of coincident events: further development of many device protocols and standards; widespread purchase of information technology-enabled devices by consumers; customer participation; addressing of privacy concerns; and finally, electricity regulators must allow time-sensitive prices to be charged to consumers. Some or all of these factors may have many anticipated and unanticipated social and economic consequences to weigh. Still, as technology marches on and allows more and more intelligent devices to exist on the many parts of the grid, the concept of transactive energy bears watching, as well as consideration.

[x] GridWise Architecture Council. "Transactive Energy." http://www.gridwiseac.org/about/transactive_energy.aspx. Accessed February 6, 2015.

[y] Hammerstrom, D.J. et al. "Pacific Northwest GridWise™ Testbed Demonstration Projects, Part I. Olympic Peninsula Project." PNNL-17167. April 2007. http://www.pnl.gov/main/publications/external/technical_reports/PNNL-17167.pdf. Accessed February 9, 2015.

[z] Giegerich, A. "What's transactive energy? PNNL's Carl Imhoff fills in the blanks." Portland Business Journal. May 23, 2013. http://www.bizjournals.com/portland/blog/sbo/2013/05/whats-transactive-energy-pnnls-carl.html. Accessed February 9, 2015.

Appropriate Valuation of New Services and Technologies and Energy Efficiency Would Provide Options for the Utility Business Model

Ultimately, the electric system exists to serve load (or the demand for electric services) from the residential, commercial, industrial, and transportation sectors. There is a suite of services that the grid provides, and a better understanding of the full costs and benefits of those services would allow regulators, utilities, and customers to develop more fair and equitable pricing structures.

It is illustrative to examine "ancillary services," which are services that ensure reliability of the grid.[168] Types of ancillary services can include ramping, local reserve requirements, voltage support, and frequency support—all of which are furnished by a combination of generation, transmission, and demand-side facilities. Ultimately, the system operator is responsible for ensuring that there are adequate ancillary services at all times to maintain reliability.

Ancillary services have typically been provided by conventional power plants with large spinning turbines running at less than maximum capacity. These resources are now being retired due to a number of factors ranging from economics to policy. Additionally, some regions are seeing significant amounts of wind and solar generation, which are not normally operated in a manner to provide ancillary services. Both NERC and FERC have stressed the need to maintain essential ancillary services for bulk power operations as the resource mix changes.[aa, 169] As the grid continues to evolve, system planners and grid operators will need to adjust to also using other technologies that can also help maintain system stability and reliability. These technologies range from energy storage, demand response, and power electronics added to both the grid and generators without large spinning turbines, to other technological approaches.

New payments, or changes to any existing payment method, to generation owners or other providers may be necessary to ensure continued provision of needed ancillary services. Most ancillary services have well-developed valuation methods. However, only some ancillary services have well-developed markets. For example, voltage control (also known as reactive power) receives a cost-based payment in some regions, while other regions require reactive power capability as part of good utility practice (i.e., without compensation). No regions currently use competitive solicitations to procure and price reactive power service.[170] Frequency response is another ancillary service that can be unvalued or undervalued. While thermal generators historically provided ancillary services in conjunction with energy (hence the name "ancillary"), new technologies, such as energy storage, demand response, power electronics, or other technological approaches, can also provide these services discretely.

[aa] Statements by FERC commissioners and various FERC rulemakings and decisions make clear the importance to FERC of maintaining reliability through use of sufficient ancillary services as the generation mix continues to evolve with retirement of traditional generation and use of more variable generation (i.e., wind and solar).

Electric Vehicles, the Distribution System, and Infrastructure Issues

In the United States, plug-in electric vehicles represent about 0.1 percent of light-duty vehicles on the road, but 0.7 percent of new light-duty vehicle sales.[ab] Annual sales have increased since plug-in electric vehicles were reintroduced in 2010. Electric vehicle service equipment installations have also grown, with public charging stations increasing from fewer than 600 in 2010 to almost 20,000 by the end of 2013.[ac] New infrastructure needs will occur should future sales of electric vehicles become significant and widespread. A refueling infrastructure that can provide for a growing number of electric vehicles will require millions of residential charging stations and a large network of public charging stations, as well as some upgrading of the electric grid—especially the low-voltage distribution network.

Deployment of residential charging stations in rural and suburban areas is relatively straightforward because a large proportion of dwelling units are capable of co-locating vehicle parking and electrical access at moderate cost.[ad] In urban areas, developing successful residential charging networks may be more difficult to achieve because fewer residencies have a garage or assigned parking place.[ae]

[ab] Argonne National Laboratory. "Light Duty Electric Drive Vehicles Monthly Sales Updates." 2014. http://www.transportation.anl.gov/technology_analysis/edrive_vehicle_monthly_sales.html. Accessed January 16, 2015.

[ac] Alternative Fuels Data Center. "Alternative Fueling Stations by State." Department of Energy. 2014. http://www.afdc.energy.gov/fuels/stations_counts.html. Accessed January 16, 2015.

[ad] Vyas, A. et al. "Plug-in hybrid electric vehicles: How does one determine their potential for reducing US oil dependence." Proceedings of the Electric Vehicle Symposium. 23(2–5). 2007. http://www.transportation.anl.gov/pdfs/HV/462.pdf. Accessed January 16, 2015.

[ae] California Plug-in Electric Vehicle Collaborative. "Plug-in Electric Vehicle Charging Infrastructure Guidelines for Multi-unit Dwellings." 2013. http://www.pevcollaborative.org/sites/all/themes/pev/files/docs/MUD_Guidelines4web.pdf. Accessed January 16, 2015.

Electric Vehicles, the Distribution System, and Infrastructure Issues (continued)

Infrastructure needs are especially crucial for battery-electric vehicles, which only run on electricity, as compared to plug-in hybrid electric vehicles, which can run on electricity or gasoline. However, the business model for public stations is difficult, as installation costs will be high,[af] and home charging may keep utilization rates low even as electric vehicle adoption increases.[ag]

The extent and timing of electric vehicle impacts on the electric grid will be driven by various factors, including local/regional consumer acceptance, battery technology developments, and the rollout of the charging infrastructure. On the bulk power system, smart grid investments can allow the shifting of recharging to off-peak periods and the avoidance of building new generation to meet recharging demand.[ah] On the distribution system, equipment upgrades can help facilitate further deployment of electric vehicles, including local distribution substations and feeders.[ai] Further, smart grid enhancements may allow electric vehicles to provide ancillary services to the grid. In each case, utilities and regulators will need to determine how to distribute the cost (e.g., upfront installation) and benefits (e.g., value of ancillary services) of grid infrastructure upgrades.

[af] Gerkensmeyer C., M. Kintner-Meyer and J.G. DeSteese. "Technical Challenges of Plug-In Hybrid Electric Vehicles and Impacts to the US Power System: Distribution System Analysis." January 2010. http://www.pnl.gov/main/publications/external/technical_reports/PNNL-19165.pdf. Accessed January 16, 2015.

[ag] Gerkensmeyer C., M. Kintner-Meyer, and J.G. DeSteese. "Technical Challenges of Plug-In Hybrid Electric Vehicles and Impacts to the US Power System: Distribution System Analysis." January 2010. http://www.pnl.gov/main/publications/external/technical_reports/PNNL-19165.pdf. Accessed January 16, 2015.

[ah] Hadley, S.W. "Impact of Plug-in Hybrid Vehicles on the Electric Grid." October 2006. http://web.ornl.gov/info/ornlreview/v40_2_07/2007_plug-in_paper.pdf. Accessed January 16, 2015.

[ai] Gerkensmeyer C., M. Kintner-Meyer and J.G. DeSteese. "Technical Challenges of Plug-In Hybrid Electric Vehicles and Impacts to the US Power System: Distribution System Analysis." January 2010. http://www.pnl.gov/main/publications/external/technical_reports/PNNL-19165.pdf. Accessed January 16, 2015.

Regulators and policymakers are responding to the operational issues and capabilities associated with new technologies. They also seek to address longer-term concerns, such as how the loss of revenue resulting from increasing numbers of some distributed energy resource installations and resultant loss of load could challenge utilities' financial viability under current business models. The full spectrum of existing and emerging technologies contributing to these challenges includes energy efficiency, combined heat and power, combined heat and power with fuel cells, gas turbines, rooftop photovoltaic, distributed wind, plug-in hybrid and all-electric vehicles, distributed storage, demand response, and transactive building controls.

An important issue for addressing the operational and business model concerns posed by new technologies centers on valuation—i.e., "What are the benefits of new services and technologies to the grid?" and conversely, "What is the cost of the services the grid provides to customers?" There is no agreement, however, on the answers. This issue has been examined in numerous valuation studies considering a variety of impacts. For example, studies provide different conclusions regarding the impacts on T&D, such as capacity avoidance, grid support services, or external impacts such as avoided GHGs; the monetized estimates they assign to a given service or impact (capacity, energy, system losses) can range by a factor of five or more.

Many of the differences are determined by local circumstances, such as existing generation fleets, fuel resources displaced, T&D system loading, and regional differences in dispatch and unit commitment decisions. Others reflect state-specific sociopolitical preferences, such as assumed monetary benefits from reducing GHG emissions or adding local jobs. There is a lack of transparent, broadly accepted methods that can be used by stakeholders to determine the costs and benefits associated with integrating new services and technologies into the grid, while respecting regional differences. Better valuation methods would empower legislators and regulators in their efforts to address their local needs as they formulate strategies and plans to provide a portfolio of electricity options that meet their state-specific goals for reliable, affordable, and clean electricity.

Transmission and Distribution Overview

Efficiency and Line Loss

T&D grids experience line losses—electricity that is generated and supplied to the system but lost before it can be consumed by end users. In general, aggregate statistics do not differentiate between T&D losses. About 6 percent of electricity generated at U.S. power plants each year is lost on the T&D system before it reaches an end use.[171] Reducing these losses would result in less generation being needed to serve load, lowering costs and pollution for the same level of service. A number of loss-reduction methods are available, ranging from larger or more conductive conductors or higher voltages used for distribution feeders, sub-transmission, and transmission lines; high-voltage, direct current for certain transmission lines; higher-efficiency transformers and related grid equipment; and distribution feeder reconfiguration with strategic capacitor placement; among others.[172]

However, the potential savings for specific loss-reduction strategies is difficult to generalize because each transmission or distribution grid situation is unique. Strategies will result in varying amounts of loss reduction depending on system configuration and usage, and losses must be valued based on power prices in each region, as well as being valued against other capital improvements.

It is important to realize that many new grid technologies will increase productivity by increasing the usage and therefore loading of the grid. As a result, energy losses can actually increase on the grid with high utilization. It is very hard at this point to assess how the dynamics of equipment that deceases or increases losses will ultimately affect grid energy efficiency. The choice of what strategy a utility will use will depend on cost analysis of the new technology, as well as the value of the energy saved or lost.

Integrating Renewables—Operational Issues

Variable renewable energy sources (i.e., wind and solar) serve increasingly higher percentages of annual demand in regions throughout the United States; in 2013, they provided 4.6 percent of total U.S. electricity generation.[173] Such variable energy offers a low-carbon source of electricity, but at high penetration levels can affect the planning, investment patterns, and operation of the power grid. Compared to conventional thermal generation, wind and solar are marked by five characteristics of particular concern to power grid operators: variability, uncertainty, location specificity, non-synchronous generation, and low capacity factors.[174]

In contrast to wind and solar, non-variable renewable sources (i.e., geothermal, biomass, and water power) are more predictable and are also dispatchable resources; as a result, they can provide grid services in the same manner as thermal generators. In addition, concentrating solar power can utilize highly efficient thermal storage, and it becomes a dispatchable resource with capacity value.

Despite the challenges, there are power systems in some regions that already integrate higher levels of variable renewable energy.[175, 176] In these cases, the impacts of variable renewable energy have not compromised reliability because planners and system operators made whatever market design and system operations changes that were needed, as well as appropriate complementary new flexible generation and new transmission or distribution investments, to address grid needs and comply with NERC's mandatory reliability provisions.[177]

Such adaptations have challenged the perception that physical or technical issues will fundamentally limit penetration of variable renewable energy. Rather, the growth of variable renewable energy penetration is primarily bounded by the economics of compensating measures that are taken to maintain system reliability.[178] These economic constraints may or may not be significant depending on the cost of additional flexible generation, demand, transmission assets, or operational or institutional arrangements, and they are collectively tied to the ongoing need to integrate not just new variable, but other new resources as well, compensating for retiring generation while maintaining reliability and affordability. For example, NERC has discussed the importance of ancillary services (ramping, local reserve requirements, voltage support, and frequency support) in the context of generation retirements and new resource mixes.[179, 180]

The grid can be considered to have "economic carrying capacity," which represents the amount of economically competitive variable renewable energy that can be added to a given system.[181] This economic carrying capacity is highly region-specific and is not fixed; however, technical and institutional changes have the potential to increase the economic carrying capacity of a given power grid over time through a number of different best practices that can increase flexibility. These best practices include improving integrated planning methodologies and increasing system flexibility in operations, markets, load, generation, transmission, and storage.[182]

Specific actions to improve economic carrying capacity—and the relative costs of those actions—vary significantly by system. Across all systems, common areas of focus include the following:

- **Increasing system flexibility at least cost**—for example, through operational improvements, large-scale participation of demand-side flexibility, storage, and increasing generator flexibility.[183]
- **Minimizing grid costs**—for example, through strategic planning, institutional coordination, and smart technologies.[184]
- **Minimizing system capacity costs**, thereby reducing the amount of reserve capacity necessary to ensure reliability at all times of the year—for example, through geographic diversity of generation sources, enhanced demand response, and storage.[185]

Flexibility and Storage

A defining characteristic of electric systems is that the level of demand can change greatly over the course of a day and over the course of a year. These load variations mean that some portion of the system's generation and transmission capacity must be designed and operated for flexibility rather than maximum efficiency, resulting in additional costs. The use of new options in flexibility and storage can help maximize asset utilization and minimize overall costs.

Flexibility

Flexibility is the ability of a resource—any component or collection of components of the power system—to respond to the scheduled or unscheduled changes of power system conditions at various operational timescales.[186] Flexibility supports three characteristics of an ideal electric system: affordability, reliability, and sustainability. Increased electric system flexibility can come from a portfolio of supply- and demand-side options, including flexible conventional generation, grid storage, new transmission, more responsive loads, and changes in power system operations.[187, 188] Smart grid components and new systems and controls will provide unprecedented, real-time visibility across the energy system. T&D planners and operators can use this information to employ the most reliable and cost-effective flexibility options. They can consider building new generation and transmission alongside other options like demand response, larger balancing areas, or storage.

Storage

In the past, storage has not played a large role in the Nation's electric system. As of August 2014, there were 317 storage facilities in the United States with a total operational capability of 21.3 GW—less than 2 percent of the total installed electricity capacity.[189]

The vast majority of the United States' utility-scale storage capacity is provided by 30 pumped-storage hydroelectric facilities totaling 16.5 GW. Water is pumped from a lower-elevation reservoir (at off-peak times when the generation cost is lowest) to a higher elevation, and at peak times, water is released back through a turbine, generating electricity when it is especially valuable. A significant amount of new pumped storage (39 GW) has been proposed for development, much in the West; these proposed facilities are in varying stages of licensing process at FERC.[190] Some have suggested that the process for licensing of pumped storage is too lengthy, and FERC now has a pilot program to test a shorter 2-year licensing period for closed-loop, pumped-storage projects.

Conventional hydroelectric generators also perform some storage functions. Pondage hydro (i.e., hydro with dams) can store water for later release and is used to shave peak load. Within engineering and environmental considerations (fish ecology and recreational use of the rivers, for example), system operators can reduce generation during low-demand times and save the water behind the dam for high-load times when the water is more valuable. Hydro facilities also can be used to actively store intermittent renewable energy. The Bonneville Power Administration provides such a service, using its vast hydro resources to support variable wind generation. Under the "storage and shaping" service, Bonneville Power Administration receives variable output from wind generation and, at a later time, provides shaped on- and off-peak energy.

Other storage technologies include thermal storage, compressed air systems, batteries, and flywheels, with approximately 1.2 GW in installed capacity.[191] These technologies can be important in many applications, such as renewables integration, T&D investment deferral, capacity, and ancillary services. DOE has funded multiple storage demonstrations of these new technologies to accelerate storage adoption and their associated benefits.[192]

The potential for storage to provide energy and ancillary services may be undervalued;[193] cost savings to the power system can be much larger than the revenue they can receive in current market structures.[194] New methods for valuing these services would aid in planning and cost allocation for storage deployment.

The growth of storage in providing the ancillary service of frequency regulation provides an example of new service valuation. Prior to 2011, generators that provided frequency regulation (balancing over durations of 5 minutes to 10 minutes) were paid regardless of whether or not they followed the operator's signal. FERC Order No. 755 viewed these undifferentiated performance payments as unjust and unreasonable and required certain system operators to incorporate a resource's speed and accuracy into a performance-based payment.[195] FERC Order No. 755 is technology-neutral and more accurately reflects operational characteristics. Following this change, electricity storage is displacing coal-fired generation in the PJM frequency regulation market. Between January 2012 and December 2013, the share of frequency regulation from coal decreased from 34.7 percent to 12.3 percent, despite coal increasing its share of delivered energy from 42.1 percent in 2012 to 44.3 percent in 2013.[196] Fast-response resources, including storage, grew from zero to provide 14 percent of frequency regulation requirements by December 2013.[197] Energy storage can be cost effective when compared to traditional generation technologies (e.g., combustion turbines) for providing balancing services.[198]

Studies have been completed on the value streams of storage at the national level[199] and, to a limited degree, in a few distribution systems; however, information on benefits and costs at the state and regional levels is lacking. There is a lack of a broadly accepted framework for evaluating benefits below the bulk system level, particularly for evaluating potential provision of multiple services.

Information Technology Interdependencies

Over the past two decades, electricity system hardware and information technology infrastructure have become more interdependent—driven by a combination of factors, including advances in sensor, network, and software technologies; the need to provide higher levels of both wide-area and deep situational awareness regarding grid conditions; and the promise of enhanced operational efficiencies. While this convergence presents new vulnerabilities, particularly to cyber threats, it also is providing opportunities for new grid-associated value streams, enhanced system performance, and more options for consumer interaction with electricity systems.[200]

Even as new hardware and software tools are enabling the collection and use of more grid data, the landscape of electricity supply and demand is changing, and more work is needed to harness information technology capabilities in order to address the emerging issues. For example, utility investment in both hardware-connected information technology networks and data management and processing architectures varies widely across the country; creating a better and more universal understanding of data value, latency requirements, and the high-value characteristics of analytic tools and network structures would pay dividends.[201]

Although AMI deployment continues to increase—having reached more than one-third of customers in 2014—many meter communication networks have been designed to support energy usage reporting, but were built with insufficient bandwidth and capabilities to support advanced distribution operations. Moreover, the wireless mesh networks built to support metering functions face resilience challenges and are likely of limited use in power restoration scenarios.

Additionally, traditional software for power grids must adapt as the industry moves away from the basic assumptions built into existing grid planning, management, and control tools. The emerging interdependence between natural gas and electric infrastructure and markets adds yet another dimension to this challenge. New methods are needed, presenting an opportunity for entrepreneurial software developers to deliver needed modeling, planning, and operational tools.

Financing

Since the days of Insull and the Edison franchises in the late 1800s and early 1900s, private investors have provided the most borrowed capital to build electricity infrastructure, with ratepayers also providing financing at times.[202] Today, the private sector continues to supply the majority of borrowed capital for electric infrastructure. Whether this capital takes the form of IOU stock or debt financing for IOUs, public power's tax-exempt (state or municipal) bonds, rural electric cooperatives private financing or Rural Utility Services loans, or private financing for newer transmission-only merchants, T&D assets historically are viewed as safe investments with predictable returns. This low-risk profile in turn attracts a wide variety of investors—from pension funds to individuals.

IOUs are responsible for 54 percent of electricity sales[203, aj] and finance the largest fraction of electric infrastructure at $90 billion dollars in 2012.[204] Transmission investments totaled $16.9 billion and distribution investments totaled $20.1 billion in 2013.[205] EEI's most recent estimate of T&D spending forecasts continued increases for each.[206] Using a combination of debt (i.e., bonds) and equity (i.e., stocks), IOUs obtain the upfront capital for large T&D projects. IOUs obtain investment-grade ratings and their corresponding attractive interest rates because the repayment is based on future electricity revenues, which is seen as a stable income source.

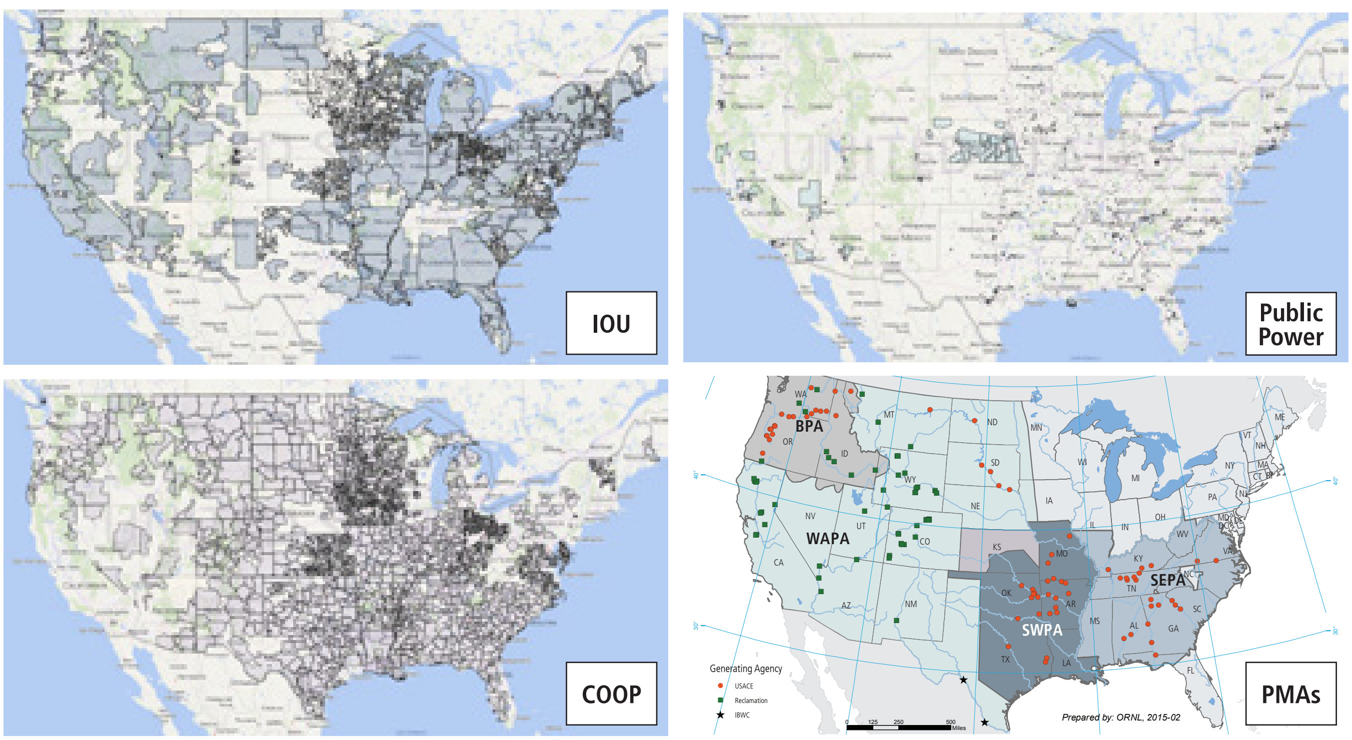
There are 2,009 publicly owned electric utilities, including those owned by states, municipalities, public utility districts, or irrigation districts.[207] Public power utilities finance energy infrastructure assets through tax-exempt revenue bonds. Revenue bonds—the predominant financing vehicle for publicly owned electric and gas utilities aside from self-financing—guarantee repayment through the revenue generated by a specific project, such as an electric generation or transmission project.

[aj] The lower number of 54 percent reflects sales by various marketers directly to end users in states that have restructured their retail electricity markets. Most of the power marketers still distribute their electricity to their end-use customer through a utility's distribution wires to that same customer. Thus, by this second measure, IOUs have 68.5 percent of total electricity customers, as reported through EIA Forms 861 and 861S.

Along with the Tennessee Valley Authority, DOE's four Power Marketing Administrations market, distribute, and—for three of the four—build the transmission to deliver hydroelectric power produced at Federal dams.[208] Capital funding for Power Marketing Administration investment can be provided by U.S. Treasury borrowing authority, customer funding, third-party financing, or Federal appropriations, depending on the various financial and legal authorities of the Power Marketing Administration. Regardless of the funding source, all program investment and expenses are repaid (with applicable interest) through rates charged to customers. The Tennessee Valley Authority was created in 1933 as a government-owned corporation for the unified development of a river basin comprised of parts of seven states. The agency is currently self-funding financing operations from power rates and borrowings.

Finally, rural electric cooperatives are consumer-owned utilities that were established to bring electricity to rural areas. These 871 utilities are located primarily in rural areas where the return on expensive infrastructure investment was not high enough to attract investment by IOUs or public power. The Rural Electrification Administration, established in 1935, provided early low-interest loans to rural electric utilities. As part of the Build America Initiative, the Department of Agriculture recently announced an additional $518 million in loan guarantees available for rural utilities.[209] The remaining 60 percent is derived from private sector sources, such as the National Rural Utilities Cooperative Finance Corporation and the National Cooperative Services Corporation. Figure C-15 shows a regional distribution of each major type of electric utility discussed. The maps show that the regional distribution of each major type does vary.

Figure C-15. Regional Distribution of Each Major Type of Electric Utility[210, 211]



The type of utility that serves any particular customer varies widely by region and state.

While utilities examine new ownership structures, the attractiveness of the underlying investment continues to enable these entities to obtain private sector financing. For example, new entities are entering the market to build transmission assets. These entities include transmission-only developers, independent transmission companies (often spun out of former vertically integrated utilities), non-core energy companies, and generation-focused independent power producers. While not widespread, there also has been at least one instance of T&D assets being organized and financed as a Real Estate Investment Trust.[212, ak, 213]

While both IOUs and public power utilities have initiated investments in electricity storage,[214, 215] early commercial deployments of large-scale storage systems often took the form of merchant projects.[216] Instead of recovering costs through regulated rates, merchant projects obtain revenue from competitive markets—primarily by selling ancillary services, such as frequency regulation.[217] These projects have been located in (or relocated to)[218] markets that place the highest value on these services, indicating that market signals more directly influence storage investment than capital cost or financial structures.

The availability of low-cost capital or non-traditional financial structures does not appear to be a major constraint to investment in electricity TS&D. Instead, primary disincentives to additional investment in electricity TS&D may include insufficient data, insufficient pricing transparency, risk aversion, project approval delays or permitting or siting issues, cost allocation, and market or policy uncertainty, as well as new technologies that do not have low enough costs to justify investment. As noted throughout this appendix, there are a variety of strategies available to address these issues. When these non-financial barriers are resolved, investors have shown a willingness to provide the capital to build grid assets.

Grid of the Future: Architecture

The grid of the future will accommodate and rely on an increasingly wide mix of resources, including large central and distributed generation—some of it variable in nature—energy storage, and responsive (transactive) load. It also will support a highly distributed architecture that integrates the bulk electric and distribution systems while enabling microgrids, ranging from individual buildings to multi-firm industrial parks that operate in both integrated and autonomous modes.

The grid of the future will need to be supported by a secure electronic communication network—its "information backbone" that will enable communication of all the grid components, from generation to the customer level (smart meters and related information technology to fully automated delivery systems). The communications network will transmit massive quantities of data to the grid's central and distributed computers to support the ability to monitor and control time-sensitive operations, including frequency, voltage, and volt-amps reactive regulation; dispatch generation; perform unit commitment; maintain dynamic line ratings; analyze and diagnose threats to grid operations; fortify resilience by providing feedback for self-healing; and evaluating data from sensors (such as synchophasors) that enable dynamic maximization of system capacity.

Business models that sustain grid investment and continued modernization while at the same time supporting new and alternative market structures will be needed. An overarching concern in its design will be meeting societal environmental objectives, such as resilience and greenhouse gas emissions reductions. Table C-4, taken from analysis recently conducted by Pacific Northwest National Laboratory for the Department of Energy, lays out a number of key architectural components of the grid of the future.

[ak] The holding company Hunt Utility Services created a 2010 real estate investment trust with investors who intend to invest $2.1 billion in electricity infrastructure. Currently, infaREIT has a subsidiary that owns and leases transmission and distribution operated by Texas-based Sharyland Utilities. See: Hunt Utility Services. "Home." www.huntutility.com/. Accessed February 6, 2015.

Grid of the Future: Architecture (continued)

Table C-4. Key Components of a Future Grid[al]

Grid Component/Opportunity	Description
AC/DC power flow controllers/converters	Technologies that adjust power flow at a more detailed and granular level than simple switching.
Advanced multi-mode optimizing controls	Controls capable of integrating multiple objectives and operating over longer time horizons, to replace simple manual and tuning controls, or controls that operate based only on conditions at single points in time.
Bilaterally fast storage	Energy storage in which charge and discharge rates are equally fast and thus more flexible.
Control frameworks	New hybrid centralized/distributed control elements and approaches.
Management of meta-data, including network models	New tools for obtaining, managing, and distributing grid meta-data, including electric network models.
Synchronized distribution sensing	Synchronization of measurements in order to provide more accurate snapshots of what is happening on the grid.
Transactive buildings	Buildings with controls and interfaces that connect and coordinate with grid operations in whole-grid coordination frameworks.
"X"-to-grid interface and integration	Interface technologies, tools, and standards for the general connection of energy devices to power grids; includes integrated mechanisms for coordinating those devices with grid operations in whole-grid coordination frameworks.
Distribution System Operation	Structure for clear responsibility for distributed reliability.

The grid of the future must be built on a business model that sustains grid investment and continued modernization while at the same time supports new products and services and will be a multi-faceted machine that produces and reliably delivers power for service to customers.

[al] Quadrennial Energy Review Analysis: Taft, J.D. and A. Becker-Dippman. "Grid Architecture." Pacific Northwest National Laboratory. PNNL-24044. January 2015. http://energy.gov/epsa/qer-document-library.

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