Electricity Baseline Report for the US Power System

Contract No. 238857

PREPARED FOR

Pacific Northwest National Laboratory

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April 2015

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This report was prepared for the Pacific Northwest National Laboratory (PNNL). All results and any errors are the responsibility of the authors and do not represent the opinion of The Brattle Group, Inc. or its clients.

Acknowledgement: We acknowledge the valuable contributions of many individuals to this report and to the underlying analysis, including members of The Brattle Group for peer review.

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I. Background

A. Focus of the Electric Baseline

The U.S. Department of Energy Office of Energy Policy and Systems Analysis requested a baseline analysis of the electric power sector. The electric baseline analysis in this report is focused on transmission, distribution, and storage (TDS) infrastructure. However, a complete picture of the country's electric power system must also address the status of the generation and end-use infrastructure, which in turn influences the needs and future development of the TDS system, as well as the market and regulatory structure in which the system operates.

This Background section of the electric power sector baseline includes an overview of generation and end-use infrastructure (in addition to transmission, distribution, and storage) and of the institutional and regulatory environment shaping infrastructure decisions. We also address the macro-level trends that have the potential to transform the requirements of the TDS infrastructure, as well as evolving business models that may change how firms serving this sector meet those requirements. Subsequent sections will examine the transmission, distribution, and storage functions and infrastructure in more depth.

B. Goals and Priorities of the Electric System

The QER's description of National Energy Goals[1] include economic competitiveness, environmental responsibility, and energy security, all of which have direct counterparts when applied to the operation and planning of the electric system. These goals provide guideposts for infrastructure decisions and for evaluating overall system performance. A brief discussion of the implications of each of those terms for the electric system is provided below.

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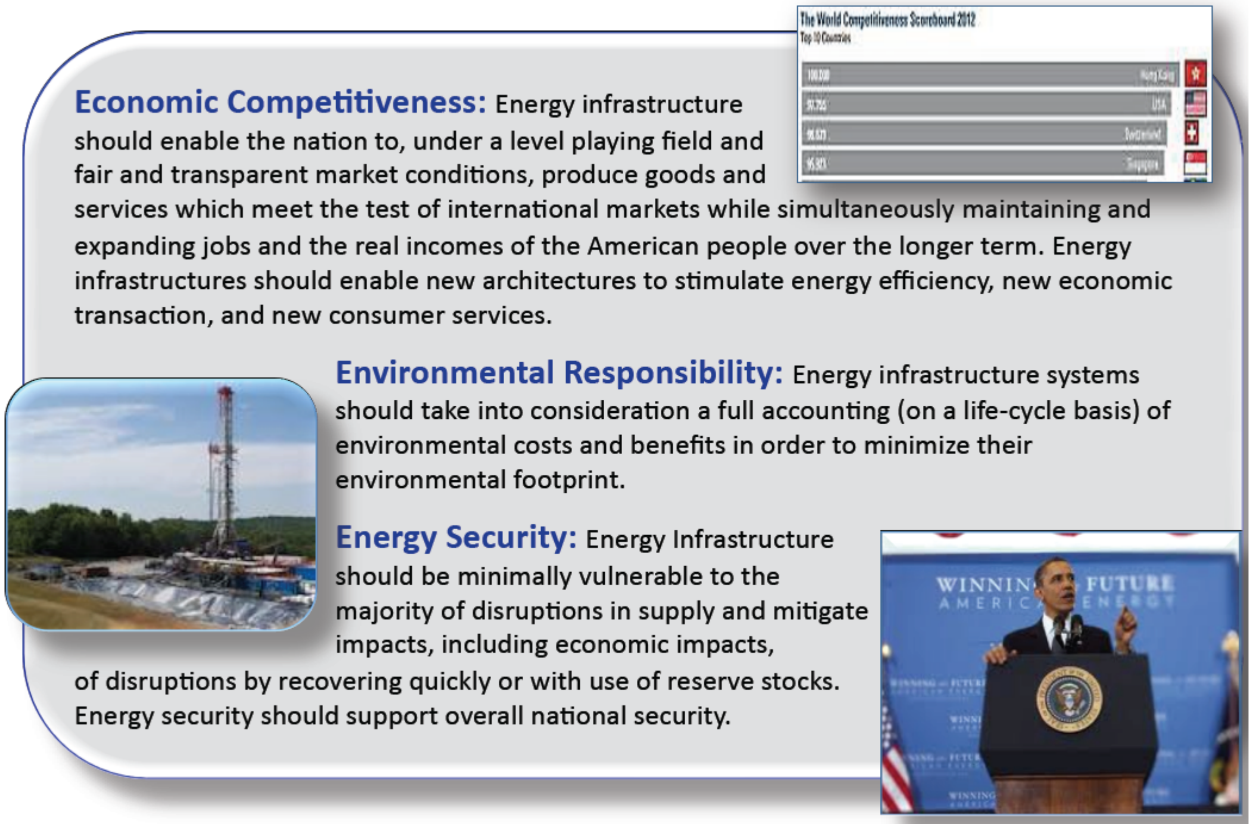
1 U.S. Department of Energy, Energy Policy and Systems Analysis, Quadrennial Energy Review: Scope, Goals, Vision, Approach, Outreach, QER Slideshow, May 15, 2014, p. 15, available at http://energy.gov/sites/prod/files/2014/06/f17/qer_public_deck_june_twothree.pdf.

Figure 1
QER National Energy Goals



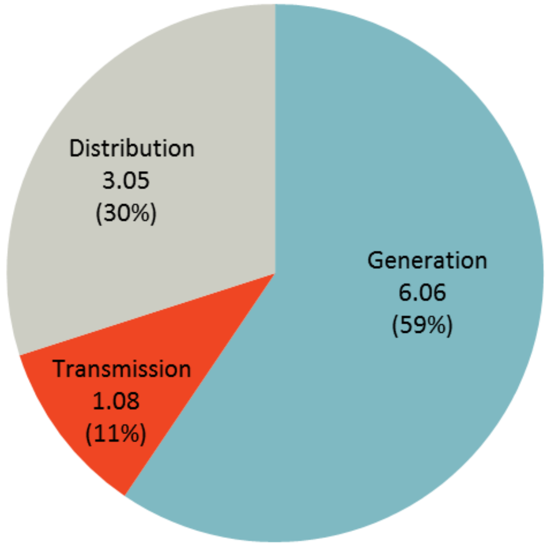
Source: U.S. Department of Energy, Energy Policy and Systems Analysis, Quadrennial Energy Review: Scope,Goals, Vision,Approach, Outreach, QER Slide show, May 15, 2014, p.15. Available at http://energy.gov/sites/prod/files/2014/06/f17/qer_public_deck_june_twothree.pdf

1. Economic Competitiveness

Retail rates reflect consumers direct cost of electricity and therefore have often been used as an indicator of the overall cost of our electric system.[2] Retail rates differ significantly across the U.S. and over time, primarily as a function of installed generation, fuel prices, the regulatory framework, and market design. The level of and trends in retail rates have direct implications for the international competitiveness of American businesses and the real incomes of American consumers. While the recent trend towards more generation at customer sites (primarily solar photovoltaic) may create situations where retail rates are no longer fully reflective of the economic costs of electricity for all consumers, retail rates will continue to be an important metric of the cost of providing electricity, and can help gauge the cost-effectiveness of infrastructure investments. Figure 2 provides an indication of the relative importance of generation, transmission, and distribution in average retail rates.

[2] There are also indirect costs associated with energy production such as environmental damage. These costs are at best only partially reflected in customer electricity bills.

Figure 2
Major Components of U.S. Average Electricity Price, 2014



Source: U.S. Energy Information Administration (EIA), *Annual Energy Outlook 2014 with projections to 2040,* DOE/EIA-0383(2014), April 2014, Table A8: Electricity Supply, Disposition, Prices, and Emissions. Available at: http://www.eia.gov/forecasts/aeo/, Reference case projection.

2. Environmental Responsibility

As stated in the QER's National Energy Goals, "Energy infrastructure systems should take into consideration a full accounting (on a life-cycle basis) of environmental costs and benefits in order to minimize their environmental footprint." In the context of electricity, the environmental footprint is multi-dimensional and affected by activities at essentially all levels of the value chain.

One of the most prominent environmental issues in the last decade has been climate change, which has been connected to greenhouse gas (GHG) emissions. Carbon dioxide accounts for about 82% of all U.S. GHG emissions. The electric sector is the source of 32% of total U.S. GHG emissions (almost all of it carbon dioxide) and these emissions will be significant for the foreseeable future.[3] The impact of electricity on greenhouse gas emissions depends both on the *amount* of electricity generated and the carbon dioxide *emissions intensity* of that generation—*i.e.*, the fuel and technology mix used to generate that electricity.

The electric sector likely will be an important source of carbon dioxide emission reductions under future policies. Many studies have shown that the lowest cost paths to achieving

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[3] U.S. Environmental Protection Agency (EPA), Climate Change, Sources of Greenhouse Gas Emissions, online at http://www.epa.gov/climatechange/ghgemissions/sources/electricity.html. Also see projections of carbon emissions from the electric sector in "Annual Energy Outlook 2014 with projections to 2040," The Energy Information Administration, April 2014.

economy-wide carbon dioxide reductions are via reductions in electric generation emissions.[4] Renewables and nuclear are very low life-cycle carbon dioxide technologies that can be added to the system to reduce the generation from coal and natural gas. In addition, natural gas generation can be increased and coal generation decreased to reduce carbon dioxide emissions.[5] These are both components of EPA's Clean Power Plan.[6]

The life cycle environmental footprint of the electric sector is much broader than carbon dioxide emissions from power plants. Other environmental concerns and issues associated with the electric industry include: emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_X), and toxic air pollutants; impacts from coal mining and natural gas drilling and production; construction and operation of hydroelectric generating capacity; disposal of fuel waste in the case of radioactive waste from nuclear power plants and ash from coal plants; siting, construction and operation of generation, transmission and distribution infrastructure, which can impact wildlife habitat and have objectionable visual and other impacts; and water usage for cooling at thermal generation facilities.

3. Energy Security

To meet the energy security portion of the QER's National Energy Goals, the infrastructure should be "minimally vulnerable to the majority of disruptions in supply," and any disruptions should be mitigated with quick recovery. In the context of electricity, this concept of energy security essentially means reliability. Traditionally, electric reliability means that any demand for electric power is met by instantaneous supply (*e.g.*, the "lights are always on"). Maintaining reliability requires that sufficient capacity is available to serve load, that generation and load are balanced, and that the system has enough generation and transmission capacity to make the system tolerant to disruption of any part of the infrastructure. The distribution system tends to be more vulnerable to outages since it is typically not designed with enough redundancy to tolerate disruption of the infrastructure due to the high cost of such redundancy. From an electric generation perspective, this also includes security of fuel supply (on-site coal inventories, reliable natural gas supply, and sometimes on-site backup oil for natural gas plants). Reliability also contributes to economic competitiveness as it is an essential factor in the economic value of electric power.

A variety of recent and future developments make the goal of reliability even more challenging. These include the increased threat of intentional physical attacks on the grid, the threat of cyber-

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4 See for example, The EMF24 Study on U.S. Technology and Climate Policy Strategies, *The Energy Journal*, Vol. 35, Special Issue 1, 2014. Available at https://web.stanford.edu/group/emf-research/docs/emf24/EMF_24.pdf.

5 As a rule of thumb, a MWh of generation from a coal-fired power plant produces one ton of carbon dioxide and a MWh of generation from a modern natural gas-fired combined cycle power plant produces about 0.4 tons of carbon dioxide. See http://www.treepower.org/globalwarming/CO2-EPRI-EvanHughes.pdf, Table 5.3.

6 http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule

attacks on the grid, possible increases in weather-related incidents that threaten the resiliency of the grid, and finally the increasing reliance on variable and uncertain sources of generation (*i.e.*, wind and solar plants, sometimes referred to as "intermittent").

C. Regulatory Structure

The electric industry is characterized by widely dispersed regulatory authority spread across a variety of jurisdictions (federal, regional, state, and in some cases local) that often have different goals and objectives. This creates a patchwork of regulatory processes that complicates any implementation of large-scale system-wide change. At the federal level the bodies that have important regulatory authority include the Federal Energy Regulatory Commission, the Department of Energy, the Environmental Protection Agency, and the Nuclear Regulatory Commission. Many other agencies such as the Department of the Interior, the Department of Justice, the Department of Transportation, and the Occupational Safety and Health Administration also have regulatory authority that affects the electric sector.

This section provides a brief overview of many of the major regulatory institutions that play a role in overseeing the electric system of the United States, and also provides an example of how this structure complicates the planning process.

1. Federal

a. Federal Energy Regulatory Commission (FERC)

The Federal Energy Regulatory Commission, or FERC, is the primary federal economic regulator concerned with the electricity industry. Its jurisdiction includes regulation of the transmission and wholesale sales of electricity in interstate commerce, the review of certain mergers and acquisitions by electricity companies, the review of siting applications for some electric transmission projects, the reliability of the transmission system, monitoring of energy markets, and licensing of hydroelectric projects.[7]

b. North American Electric Reliability Corporation (NERC)

The North American Electric Reliability Corporation (NERC) is a nonprofit entity whose mission is to "ensure the reliability of the bulk power system in North America."[8] In accordance with the Energy Policy Act of 2005, the FERC designated NERC as the national "Electric Reliability Organization" of the United States. As a result, NERC's previously voluntary guidelines for power system operation and accreditation have been revised into Standards, which it now has the authority to enforce on power system entities operating in the U.S. (and several provinces in Canada).

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7 Federal Energy Regulatory Commission, About FERC/What FERC Does, online at http://www.ferc.gov/about/ferc-does.asp.

8 North American Electric Reliability Corporation (NERC), About NERC, online at http://www.nerc.com/AboutNERC/Pages/default.aspx.

The reliability standards are contained in a 1,900 page document that covers a broad range of generation and transmission reliability requirements.[9] The standards cover 14 categories, and set out a variety of specifications, requirements, and penalties within each category. For example, the cyber security rules:

- Specify ”responsible entities,” which include NERC, utilities, and transmission owners
- Have procedures for identifying “Critical assets,” which includes transmission and generation assets and control centers
- Have procedures for identifying transmission and generation cyber assets
- Specify detailed technical guidelines
- Specify management controls
- Outline staff training in detail
- Specify violations and their severity.

The standards also cover areas such as coordination between nuclear plants and transmission operators to ensure safe operations of the nuclear plants, and modeling, data and power system analysis.

c. Other Federal Agencies

There are additional federal programs with direct effects on the development of infrastructure of the electric system. These include environmental standards on power plant emissions as administered by the Environmental Protection Agency (EPA), and appliance and equipment standards for energy efficiency as administered by the Department of Energy (DOE).[10]

EPA’s primary authority stems from federal legislation such as the Clean Air Act (1970/1977) and Amendments (1990), the Clean Water Act (1972), and the Resource Conservation and Recovery Act (1976). Under these acts, EPA regulates air, water, and solid waste products from power plants. The most important of these are shown in Table 1.

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9 NERC, Reliability Standards for the US Bulk Electric System of North America, Updated September 17, 2014.

10 DOE, Office of Energy Efficiency and Renewable Energy, About the Appliance and Equipment Standards Program, online at http://energy.gov/eere/buildings/about-appliance-and-equipment-standards-program.

Table 1
Summary of EPA Regulations Expected to Impact Electric Power Sector

Regulation	Status	Pollutant Targeted	Compliance Options	Expected Date of Compliance	EPA Source
Mercury and Air Toxics Standards (MATS)	Final	HAPs (mercury, acid gases, PM)	Activated Carbon injection (ACI), Baghouse, Flue Gas Desulphurization (FGD)/Dry Sorbent Injection (DSI)	2015/2016	http://www.epa.gov/mats/
Cross-State Air Pollution Rule (CSAPR)	Reinstated by Court on Apr 29th, 2014	NO_x, SO_2	Selective Catalytic Reduction (SCR)/Selective Non-Catalytic Reduction (SNR), FGD/DSI, fuel switch, allowance purchases	Potential replacement rule after 2015?	http://www.epa.gov/airtransport/CSAPR/
Clean Power Plan (CPP)	Proposed Rule June 2014	GHG	Potential for trading of allowances depending on state/regional plans	2020	http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule
Cooling Water Intakes 316(b)	Final	Cooling water and intake structures	Impingement: Mesh screens; Entrainment: Case-by-case, may include cooling towers	the permitting authority to establishes a compliance schedule	http://water.epa.gov/lawsregs/lawsguidance/cwa/316b/
Combustion by-products (Ash)	Final	Ash, control equipment waste	Bottom ash dewatering, dry fly ash silos, etc.	2018	http://www2.epa.gov/coalash/coal-ash-rule
Regional Haze	Final	NO_x, SO_2, PM	SCR/SNCR, FGD/DSI, Baghouse/Electrostatic Precipitator (ESP), combustion controls	Typically 5 years after ruling	http://www.epa.gov/airquality/visibility/actions.html

Source: The Brattle Group

Many of these federal rules result in standards that vary at the state or regional level, often not coinciding with power markets. A good example of this is EPA's proposed Clean Power Plan, which establishes state-specific carbon dioxide emission rates for a subset of power plants, even though states may be in one or more regional wholesale power market.

The DOE has set efficiency standards on appliances since 1975; today minimum energy efficiency standards cover about 50 categories of appliances and equipment, representing 90% of home energy use, 60% of commercial building energy use, and 29% of industrial energy use.[11] For example, this year DOE has established new energy conservation standards for commercial walk-in coolers and residential furnace fans. There are four Federal Power Marketing Administrations that also reside within the DOE.

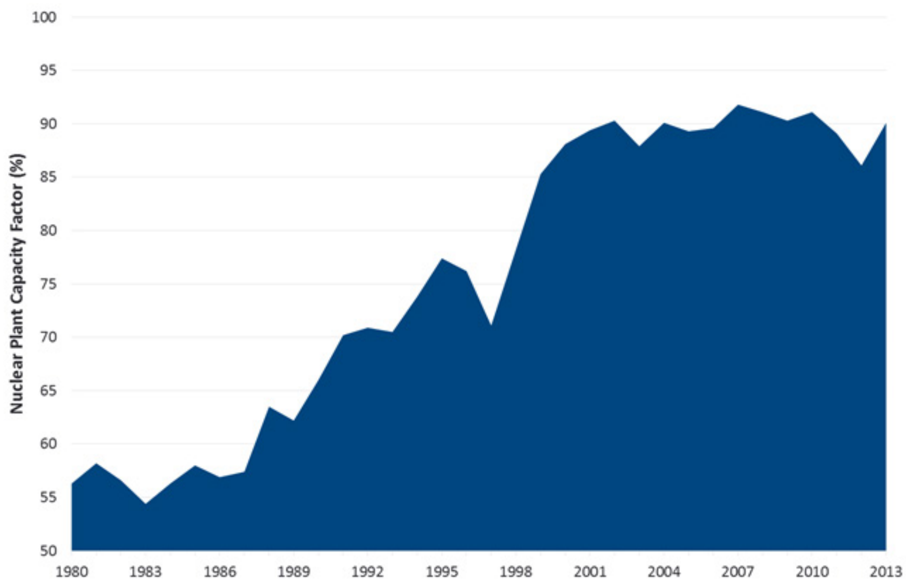
d. The Nuclear Regulatory Commission (NRC)

The NRC licenses existing and new nuclear plants and monitors the operation and safety performance of the 100-unit nuclear fleet. The nuclear fleet produced about 20% of U.S.

11 *Id.*

electricity in 2012.[12] The nuclear generation fleet performance, as measured by capacity factor, has been outstanding for more than 15 years, as shown in Figure 3.

Figure 3
U.S. Nuclear Plant Average Capacity Factor



Source: U.S. Energy Information Administration, Annual Energy Review 2011, and Monthly Energy Review, October 2014. Available at http://www.eia.gov/totalenergy/data/browser/xls.cfm?tbl=T08.01 and http://www.eia.gov/totalenergy/data/monthly/archive/00351410.pdf

2. States

Individual states also have important regulatory authority over the electric power infrastructure located within their respective borders. State regulatory authorities set retail rates and revenues; oversee resource adequacy and distribution reliability for investor-owned utilities; permit generation and transmission infrastructure; and fund utility programs to pursue new technologies, such as renewables, energy efficiency, and storage technologies.

Examples of state-level environmental regulations include regulation of mercury, NO_X, and SO_2 emissions in Illinois and Maryland. Similarly, with AB 32, California has adopted state-level regulation of greenhouse gas emissions, and nine states in the northeast are active participants in the Regional Greenhouse Gas Initiative (RGGI). These are both cap-and-trade programs that have economic and regulatory implications for the generation mix (and thus infrastructure development) in those states as well as neighboring states.[13]

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[12] U.S. Energy Information Administration (EIA), *Annual Energy Outlook 2014 with projections to 2040,* DOE/EIA-0383(2014), April 2014. Available at: http://www.eia.gov/forecasts/aeo/.

[13] See http://www.epa.gov/airmarkets/documents/ipm/Chapter_3.pdf Table 3-13 for a summary of state environmental policies that affect the electric sector.

An additional example of state policies impacting the nation's electric system is the renewable portfolio standard (RPS), a policy that has been adopted by thirty states and the District of Columbia.[14] These are regulations passed by state legislatures that require increased production from renewable energy sources. Though there is wide heterogeneity in RPS policies, they tend to incentivize renewable capacity expansion in the states where they have been passed and have driven much of the renewables expansion in the past decade.[15]

For publicly-owned and cooperatively-owned electric utilities, most, but not all, state laws have given the equivalent public utility commission oversight of them to their locally elected or appointed boards.

3. Status of Restructuring

The restructuring of retail electricity markets is an additional dimension in which state legislative and regulatory actions have influenced and will continue to influence the development of the electric system in the United States. Electric restructuring in some form is active in fifteen states, plus the District of Columbia, as depicted in Figure 4.

In those states, some or all retail customers of Investor-Owned Utilities (IOUs) have the option of purchasing their electric energy services (though not their distribution services, *i.e.*, that directly connects the wires to the customer) from competitive suppliers. In most of these states, the IOUs have been required to divest their generating assets (and in some states even transmission) and evolve into "wires companies" that own just transmission and distribution assets.

In states that have separated generation from the transmission and distribution functions, planning, such as "integrated resource planning, is no longer centralized. The decision to add new generation capacity is made by merchant generators that can either have a contract to sell their power to an IOU or sell power at market prices. Ultimately the decision to enter the market and the type of plant to add is made based on the economics from the independent power producer's (IPP's) point of view and is not necessarily based on reliability or need from a system perspective.

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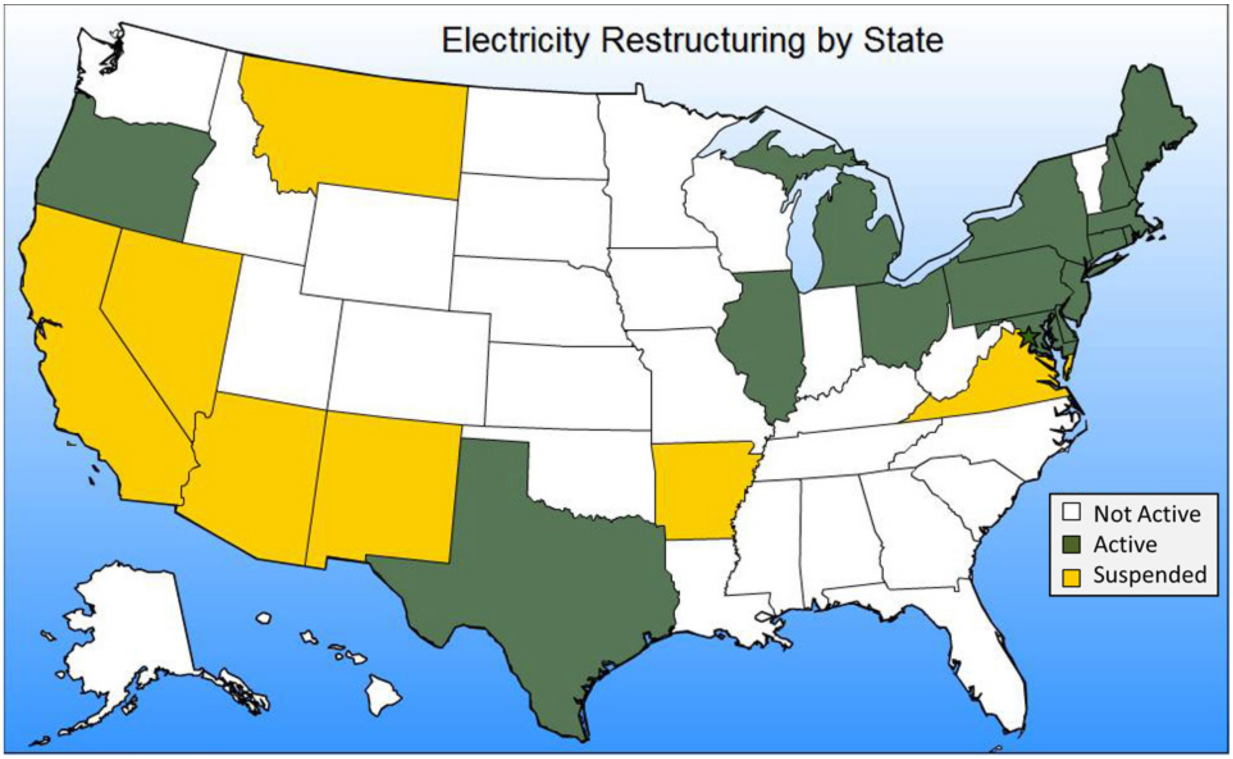
14 U.S. Energy Information Administration, Today in Energy, Most states have Renewable Portfolio Standards, February 3, 2012, online at http://www.eia.gov/todayinenergy/detail.cfm?id=4850.

15 Yin, Haitao and Nicholas Powers, "Do state renewable portfolio standards promote in-state renewable generation?" *Energy Policy,* 38(2), February 2010, 1140–1149. Available at http://www.sciencedirect.com/science/article/pii/S0301421509008283

Figure 4



Source: U.S. Energy Information Administration.
http://www.eia.gov/electricity/policies/restructuring/restructure_elect.html

4. Planning Process

This regulatory patchwork means that any system-level planning process is complex, adding to the engineering and economic complexity of designing a reliable and economically efficient electric system. One example is provided by transmission planning processes. Transmission planning is most commonly undertaken at the level of the Balancing Authorities (BAs). These entities perform technical analyses of their system to identify potential violations of NERC reliability standards as well as complex cost-benefit analyses to justify new construction. New transmission projects often have effects on neighboring balancing authorities, making the process regional in nature. Nonetheless, in almost all cases, the states have oversight of any siting and permitting decisions, and often resource adequacy. This complexity will be further discussed in the transmission chapter, but it should be clear that transmission improvements or expansions are multi-stakeholder processes that rarely play out the same way twice.

5. New Developments that Challenge Jurisdictional Boundaries

When the Federal Power Act was passed in 1935,[16] almost every utility was located wholly within a single state and power lines that traversed state lines were relatively new. States had already established regulatory authorities for their in-state utilities, but states, due to the Commerce Clause in the Constitution,[17] could not assert jurisdiction over trades between utilities in different states. The Federal Power Act gave power to the already-existing Federal Power Commission (the predecessor to the FERC), and also created the current Federal-State regulatory boundary: state oversight of retail rates, asset permitting, and any state policies affecting electricity resource choices by utilities; and federal oversight of interstate transactions and transmission. This structure would remain for several decades before climate change, energy efficiency, EPA regulations, rooftop solar, centralized wholesale electric markets, and "smart grid" would highlight the challenges and issues in maintaining the status quo.

Today's power industry—already vastly changed from the 1930s—is seeing major new trends that may further stretch the regulatory structure in place today. For example, the changing technology of the electric grid that places more control and options in the hands of consumers is transforming the articulated legal boundary between wholesale and retail transactions. Individual electric customers are becoming increasingly capable of generating and selling, in addition to buying, some of their power. FERC-regulated regional grid operators are on the verge of using large information technology systems to control individual home generators and even home appliances minute-by-minute to balance the grid, should state-federal jurisdictional issues not interfere.

In this new future, the boundaries in the regulatory structure that made sense in 1935, when it was largely unthinkable for individual customers to enter into a transaction that had any measurable impact on the interstate power grid, may no longer be optimal.

While technology is obscuring the current state-federal boundary, there remains a need for both levels of government to play a role in the regulation of the power sector. But, revisions to the 1935 Federal Power Act are likely required. While the notions of intra-state versus inter-state and retail versus wholesale have become blurred, the states still have a strong and important role in electricity regulation. The variety and strength of state policies on energy efficiency, renewable energy, nuclear power, coal, natural gas, electric markets, smart grid, and even greenhouse gas regulation demonstrates the undiminished importance of the power sector to state leaders, technological change notwithstanding. At the same time, portions of the electric power sector that continue to be seen as under state jurisdiction (*e.g.*, demand response) have an important role to play in improving the efficiency of the wholesale markets overseen by FERC at the federal level.

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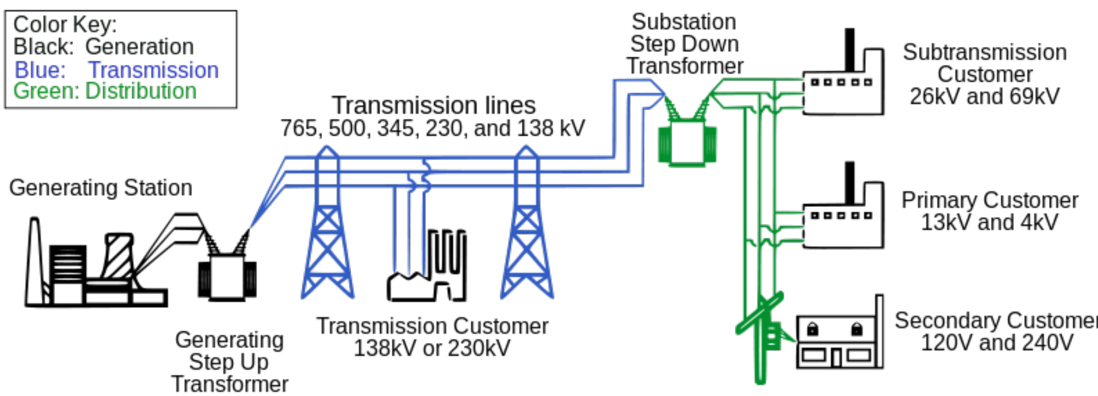
16 Online at http://www.wapa.gov/dsw/pwrmkt/BCP_Remarketing/BCP/BCP%20Information%20Module/Timeline/FederalPowerAct1935.pdf

17 https://www.law.cornell.edu/wex/commerce_clause/

D. PHYSICAL AND OPERATING STRUCTURE

The physical structure of the electric system is usually divided into one of four functions: generation, transmission, distribution, and consumption. The first phase of the QER adds storage and control as two additional functions, but here we will focus on the more traditional four. All have important roles to play in terms of system reliability. Each of these four functions is discussed in further detail below. Although this baseline report focuses on TDS, generation and end-use infrastructure are important to understanding reliability at a system level, and are thus included here for completeness.

Figure 5
Traditional Structure of the Electric System



Source: U.S. Department of Energy, Office of Electricity Delivery and Energy Reliability, Infrastructure Security and Energy Restoration (DOE/OE/ISER) *Large Power Transformers and the U.S. Electric Grid*, June 2012, p. 5. Available at http://energy.gov/sites/prod/files/Large%20Power%20Transformer%20Study%20-%20June%202012_0.pdf.

1. Generation

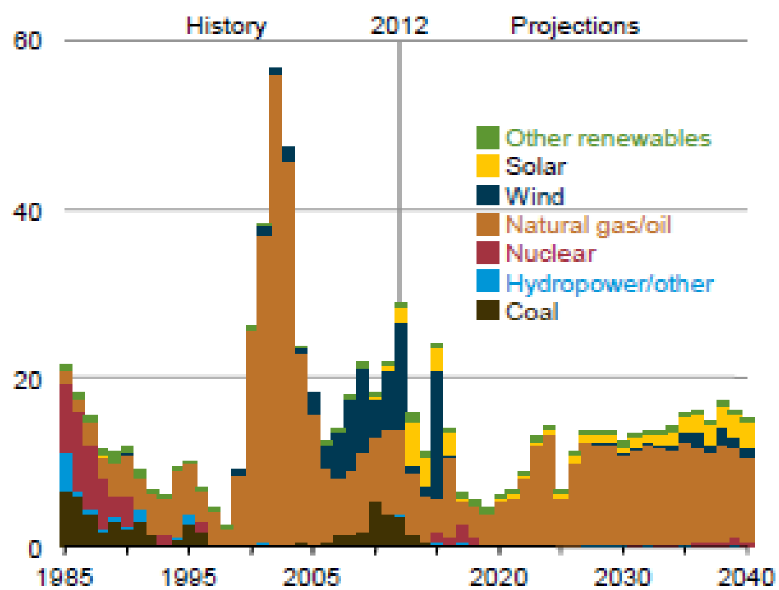
Generation is the process of converting primary energy sources (such as fossil, nuclear, or renewable) into electricity. Generating units represent large capital investments in a particular technology and, once built, are usually intended to operate for many decades. In the past, the most economical sources of generation have been coal plants, nuclear plants, natural gas power plants, and large-scale hydroelectric dams, though there is a great degree of geographic variation in the economics of generation, based on primary energy availability and cost, as well as other geographic characteristics.

Fossil-fuel generation, geothermal, biomass and hydroelectric technologies are "dispatchable" (*i.e.*, operators can decide on how much power to provide from a given unit) in order to match supply with fluctuations in demand. In other words, as long as the plant operator has the generation unit online, and the unit has sufficient fuel, the plant can be called on to raise or lower output as needed within its operating range, although the speed or "ramp rate" at which output can be changed is often quite limited.

Natural gas-fired technologies have increased in capacity the most over the past ten years, as shown in Figure 6, and are projected to remain the dominant new technology through 2040. New natural gas capacity continues to improve in efficiency, start times, and ramp rates.

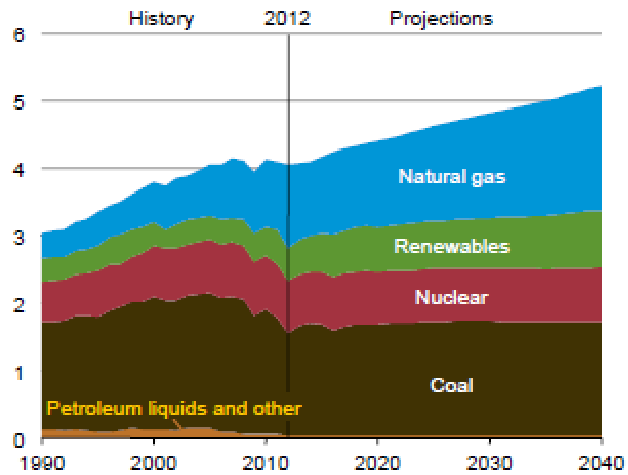
Solar and wind capacity has become an increasing portion of the supply mix, and is expected to become an even greater part in the future. These generating technologies pose new challenges to the overall system, in that they are not available on demand because their output is affected by wind speed or solar insolation. At the same time, natural gas-based generation has grown, and is expected to continue to grow, in importance to overall generation, as illustrated in Figure 7. While driven by economic and regulatory factors, the increasing importance of natural gas (largely at the expense of coal and nuclear) counteracts some of the problems caused by the intermittent nature of solar and wind plants, as natural gas simple- and combined-cycle plants using combustion turbines generally require less time to start up than do coal or nuclear plants using steam cycle technologies, and can be moved more quickly within their operating range—"ramping up" or "ramping down."

Figure 6
Additions to Electricity Generating Capacity in the Reference Case, 1985–2040 (Gigawatts)



Source: EIA Annual Energy Outlook 2014. Figure MT-32.

Figure 7
Electricity Generation by Fuel in the EIA Annual Energy Outlook Reference Case, 1990–2040 (Trillion Kilowatt-Hours)



Source: EIA Annual Energy Outlook 2014. Figure MT-30.

At a system level, another important concept relating to the reliability of the generation fleet is that of "reserve margin," which is the surplus in generating capacity that maintains a margin or buffer in order to deal with unexpectedly high net demand and/or equipment failures. The reserve margin expresses the amount of capacity above expected peak demand needed to meet a reliability target. For example, if consumer demand peaks at 150,000 megawatts (MW) during a single hour on a hot summer day, and the installed capacity is 172,500 MW, the reserve margin is 15%.[18] Projections by the North American Electric Reliability Corporation (NERC) of reserve margins across the U.S. show that the majority of regions are projected to remain above the reference level, while the Midcontinent Independent System Operator (MISO) and the Electric Reliability Council of Texas (ERCOT) are the regions most likely to fall below the reference level, as shown in Figure 8, if additional resources are not built by 2018.[19]

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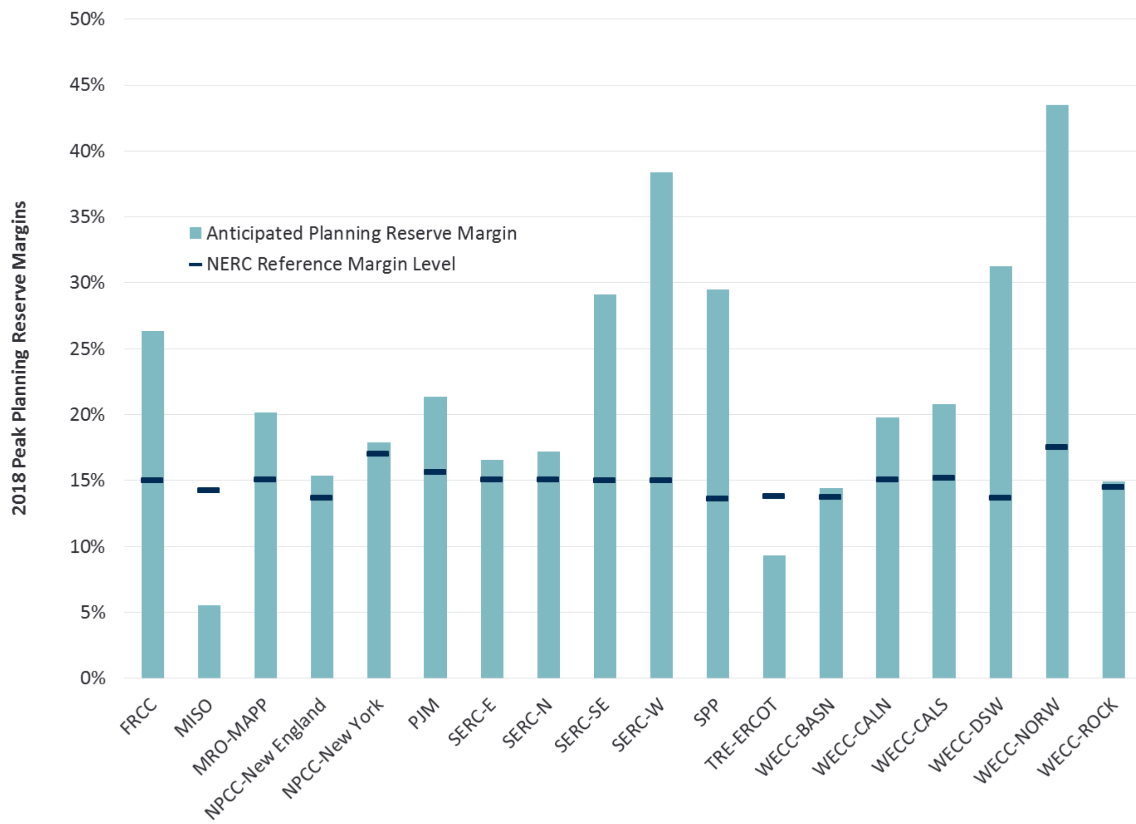
18 (172,500 – 150,000)/150,000 = 15%.

19 NERC, 2013 Long-Term Reliability Assessment, December 2013. Available at: http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2013_LTRA_FINAL.pdf. NERC projects "anticipated planning reserve margins" for each region based on its analysis of existing and planned generation capacity, net firm capacity transactions, and all categories of demand response treated as a resource and the net internal demand.

Figure 8
NERC Projections of 2018 Peak Planning Reserve Margins



Source and Notes: NERC, 2013 Long-Term Reliability Assessment, December 2013. NERC projects "anticipated planning reserve margins" for each region based on its analysis of existing and planned generation capacity, net firm capacity transactions, and all categories of demand response treated as a resource and the net internal demand. Definitions of each category can be found on page vi.

Customer outages due to lack of generation are very rare. Installed capacity reserves have provided sufficient capacity to avoid almost all customer outages under even the worst conditions. The 2014 polar vortex affected much of the country and resulted in winter peak loads 10%–20% higher than historic peaks. At the same time, units failed due to frozen equipment, and some units experienced outages due to cuts in non-firm natural gas supply. But there were only very limited involuntary customer outages due to a lack of generation.[20] The Tennessee Valley Authority and South Carolina Electric and Gas both experienced some customer outages.[21]

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20 NERC, *Polar Vortex Review*, September 2014. Available at http://www.nerc.com/pa/rrm/January%202014%20Polar%20Vortex%20Review/Polar_Vortex_Review_29_Sept_2014_Final.pdf

21 See Tweed, Katherine, "Polar Vortex Cripples Power Generation, But Grid Survives, *IEEE Spectrum*, online at http://spectrum.ieee.org/energywise/energy/the-smarter-grid/polar-vortex-cripples-power-generation-but-grid-survives.

In 2011, ERCOT experienced record summer loads and had very thin reserve margins, but no load was involuntarily shed.[22] However on February 2, 2011 ERCOT shed 4,000 MW of firm load due to a cold snap that resulted in record winter peak load, unit failures, and fuel supply problems.[23]

In 2000–2001 California experienced rolling blackouts caused by a combination of supply inadequacies (drought in the northwest reducing hydro availability), and a failed market implementation (market manipulation to induce scarcity).

In addition, generation capacity plays an important role in maintaining reliability by reserving capacity that can be moved quickly to respond to unexpected imbalances in load and generation, which are often referred to as "ancillary services." This need can arise due to differences between projected and actual load, unexpected loss of generation or transmission capacity, or sudden changes in output from intermittent generation resources. In addition, some units are designated as "must run" because their operation is important for grid stability and reliability. These units are always online when available.

2. Transmission

Transmission is the high-voltage transfer of electric power from generating plants to electrical substations located near demand or load centers. These substations represent the boundary between the transmission system and the distribution system which serves retail customers. There are roughly 170,000 miles of high-voltage transmission lines in the United States, as shown in Table 2. NERC does not account for the large amount of transmission below 200kV. Accounting for transmission below 200 kV shows that there are about 642,000 miles of high-voltage (over 34 kV and up) transmission lines.[24]

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22 Load shedding refers to the deliberate shutdown of electric service in part or parts of an electric system, usually in order to prevent the failure of the entire system when demand exceeds available supply.

23 Potomac Economics, Ltd., *Investigation of the ERCOT Energy Emergency Alert Level 3 on February 2, 2011*, Report by the Independent Market Monitor for the ERCOT Wholesale Market submitted to the Public Utility Commission of Texas and the ERCOT Board of Directors, April 21, 2011. Online at http://www.ercot.com/content/meetings/board/keydocs/2011/0517/Item_05_-_Independent_Market_Monitor_Report.pdf.

24 There is considerable transmission below 200 kV that is not included in Table 2. The more inclusive total miles figure includes capacity that is sometimes also called subtransmission, such as at 34 kV. The larger number of miles is from Edison Electric Institute, "EEI Statistical Yearbook 2013", Table 10.6. http://www.eei.org/resourcesandmedia/products/Pages/ProductDetails.aspx?prod=617A7D67-9678-44FC-AE6F-6876ADAE7406&type=S

Table 2
Approximate Transmission Lines by Voltages above 200 kV

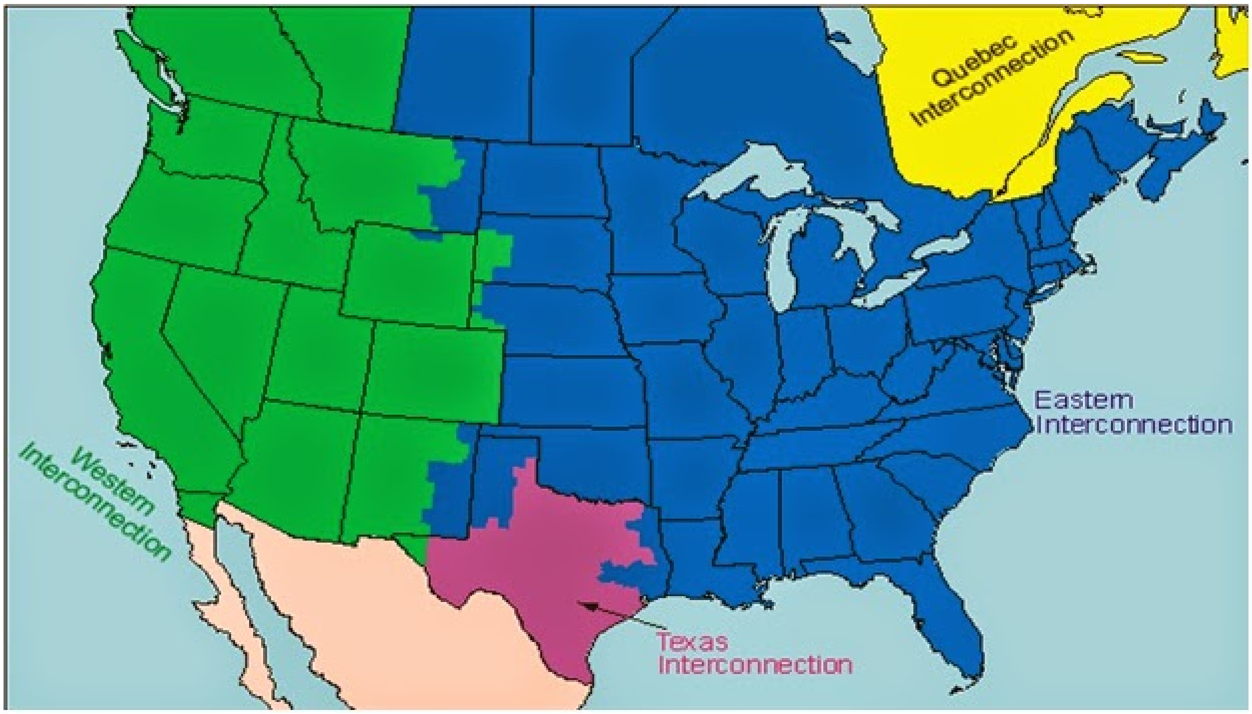
Voltage *kV*	Alternating Current (AC) *Miles*	Direct Current (DC) *Miles*
200-299	81,099	270
300-399	58,236	0
400-599	30,662	1,465
≥ 600	2,361	264
Total	**172,359**	**1,999**

Source: NERC Electricity Supply & Demand Database, Released December 2013. Available at http://www.nerc.com/pa/RAPA/ESD/Pages/default.aspx

The North American transmission network is made up of four separate grids of Alternating Current (AC) interconnections: Eastern, Western, Texas, and Quebec, as depicted in Figure 9. The four interconnections are electrically independent from each other and are only connected together through a handful of asynchronous Direct Current (DC) ties that allow for relatively small amounts of scheduled power to transfer between the grids.[25] BAs within each interconnection balance load (customer demand) and generation and have primary responsibilities in transmission planning (see Figure 10).

25 Asynchronous DC allows a controlled flow of energy between two power systems while also functionally isolating the independent AC frequencies of each side—in essence creating a “pipe” between the two systems.

Figure 9
North American Electric Interconnections



Source: North American Electric Reliability Corporation, "Balancing and Frequency Control," January 26, 2011. Available at: http://www.nerc.com/docs/oc/rs/NERC%20Balancing%20and%20Frequency%20Control%20040520111.pdf

There are 77 BAs in North America[26]; each is connected to neighboring BAs via transmission lines. The BAs are coordinated by 16 Reliability Coordinators (RCs).[27] The BAs operate the systems for which they are responsible, while the RCs are responsible for wide-area coordination.

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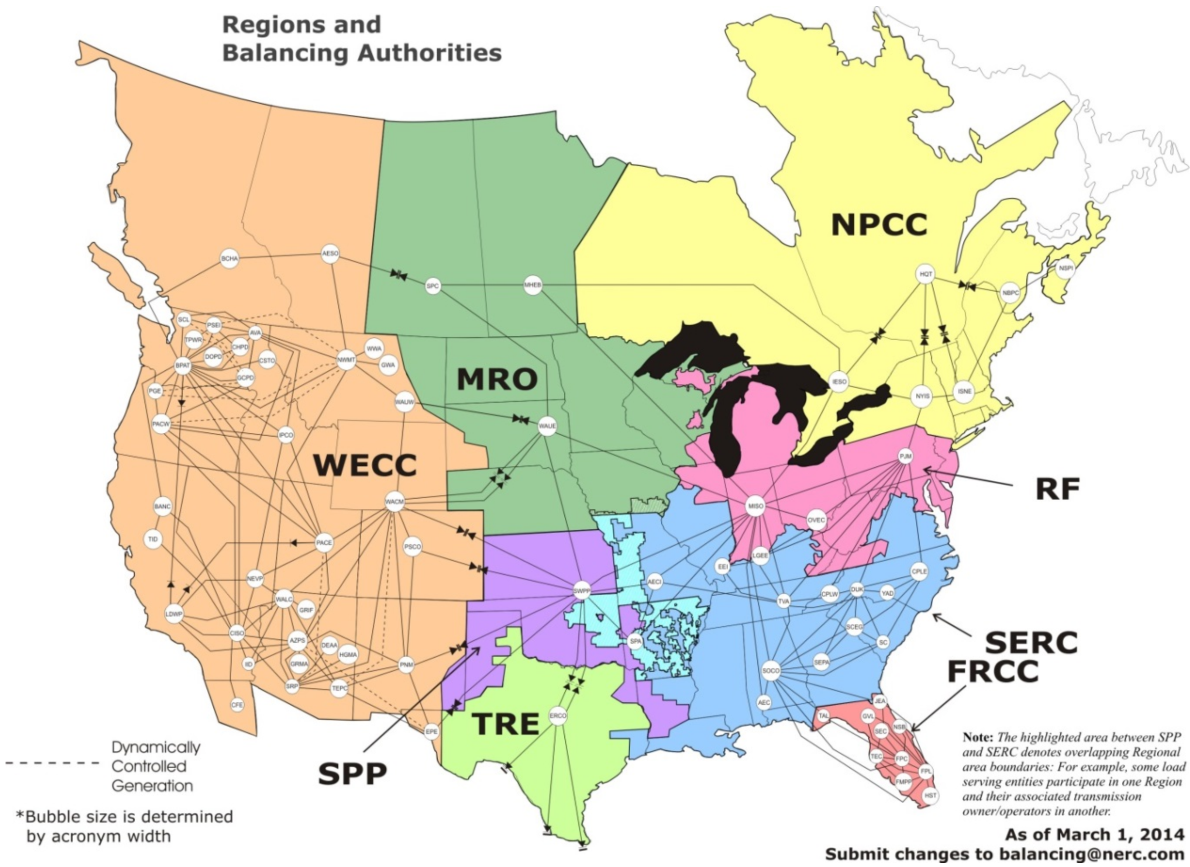
26 NERC Regions and Balancing Authorities Map, online at http://www.nerc.com/comm/OC/RS%20Landing%20Page%20DL/Related%20Files/BA_Bubble_Map_20140630.jpg

27 NERC, Reliability Coordinators, online at http://www.nerc.com/pa/rrm/TLR/Pages/Reliability-Coordinators.aspx

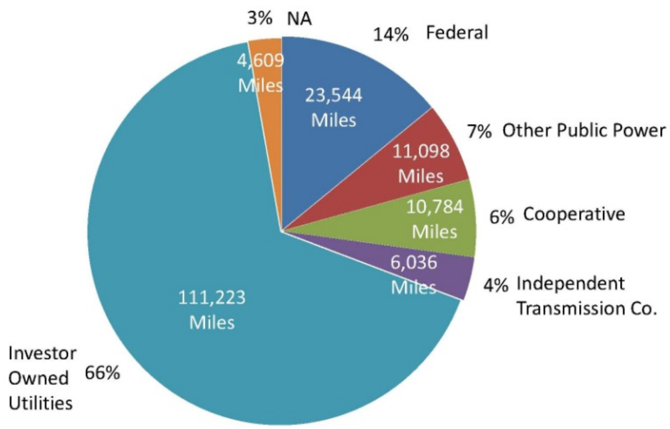
Figure 10
NERC Regions and Balancing Authorities



Source: NERC, Key Players, online at http://www.nerc.com/AboutNERC/keyplayers/Pages/default.aspx

Transmission lines are primarily owned by investor-owned utilities (IOUs) and public power as well as cooperatively-owned utilities within each interconnection, but new business models, including independent transmission companies and "pure-play" merchant transmission firms, are beginning to take shape. These firms acquire, develop, build, and operate transmission projects as their core business. Figure 11 provides a breakdown, by ownership type, of high voltage transmission capacity.

Figure 11
High Voltage Transmission Ownership



Source: Willrich, Mason, Electricity Transmission Policy for America: Enabling a Smart Grid, End-to-End, n.d., p. 11. Available at: http://gspp.berkeley.edu/assets/uploads/page/CEPP_Willrich_111809.pdf.

Although rare, major transmission outages can and have led to widespread blackouts. The most recent blackout in the eastern United States occurred on August 14, 2003, affecting large portions of the Midwest, Northeast United States, and Ontario. An estimated 50 million people were affected in Ohio, Michigan, Pennsylvania, New York, Vermont, Massachusetts, Connecticut, New Jersey, and Ontario. [28]

The U.S.-Canada Power System Outage Task Force in its final report on the causes of the blackout identified four "groups" of causes, which sometimes was popularized as "tools, trees, and training":

> *Group 1:* Failure to determine and understand inadequacies with respect to appropriate voltage criteria.
>
> *Group 2:* Failure to recognize the deteriorating situation.
>
> *Group 3*: Failure to manage tree growth along transmission rights-of-way adequately.
>
> *Group 4:* The reliability coordinator's lack of data and systems to detect and be aware of the situation as it unfolded, and lack of effective oversight.

At least partially in response to this blackout, the Energy Policy Act of 2005 authorized the FERC to issue mandatory reliability standards, which carry a maximum fine of $1 million per violation, and each day may be considered a separate violation. Prior to the Energy Policy Act, voluntary guidelines had been set by NERC and the NERC regions.

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[28] U.S.-Canada Power System Outage Task Force, *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations*, April 2004. Available at http://energy.gov/oe/downloads/us-canada-power-system-outage-task-force-final-report-implementation-task-force

In September of 2011, the Pacific Southwest including San Diego experienced a major blackout due to shortcomings similar to those that led to the 2003 eastern blackout. The FERC and NERC concluded that had the transmission system been operated properly, this blackout would not have occurred.[29]

3. Distribution

Distribution is the delivery of power from the transmission system to the end-users of electricity. There are almost 6.3 million distribution line-miles in the U.S.[30] 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 the 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. Edison Electric Institute (EEI) estimates that $275 billion has been invested in the country's distribution system since 2000.[31]

Electrical losses affect both transmission and distribution systems. Line losses are energy that is generated and supplied to the system but lost due to the resistance of wires before it can be consumed by end users. In general, aggregate level statistics do not differentiate between transmission and distribution losses. Roughly 5 percent of the electricity generated in the United States is lost each year in transmission and distribution.[32]

Distribution outages that affect customers are much more common than either generation or transmission outages. When customers experience outages it is almost always due to problems on the distribution system, but these outages tend to be localized except during severe weather events or natural disasters, like Hurricane Sandy. Weather events, accidents, and even animals climbing on certain pieces of equipment are all common causes of distribution outages.[33]

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[29] Staffs of the Federal Energy Regulatory Commission and the North American Electric Reliability Corporation, *Arizona-Southern California Outages on September 8, 2011: Causes and Recommendations*, April 2012. Available at http://www.nerc.com/pa/rrm/ea/September%202011%20Southwest%20Blackout%20Event%20Document%20L/AZOutage_Report_01MAY12.pdf

[30] "Platts UDI Directory of Electric Power Producers and Distributors", 122nd Edition of the Electrical World Directory, 2014, p. vi.

[31] Edison Electric Institute (EEI), Issues & Policy, Distribution, online at http://www.eei.org/issuesandpolicy/distribution/Pages/default.aspx.

[32] U.S. Energy Information Administration (EIA), FAQ: How much electricity is lost in transmission and distribution in the United States? last updated May 7, 2014, online at http://www.eia.gov/tools/faqs/faq.cfm?id=105&t=3.

[33] See, *e.g.*, Duke Energy, North Carolina, Outage & Storm Information, Causes of Power Outages, September 2011, online at http://www.duke-energy.com/north-carolina/outages/causes.asp.

Traditionally, utility outage management systems have relied on calls from customers to identify and locate the source of outages. One benefit of advanced metering infrastructure (AMI, discussed in detail in the Distribution section) is the ability for utilities to be aware of distribution outages in real-time. Restoration alert systems built into the AMI allow utilities to see the status of individual meters and focus restoration efforts where needed. Pacific Gas and Electric (PG&E) has reported that with the introduction of smart grid technology customer outages came down in 2013 to the lowest levels ever observed by PG&E.[34]

4. 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 U.S. with a total operational capability of 23.4 GW, which is less than 2% of the total installed electricity generation capacity.[35] The vast majority of the storage capacity in the United States is currently provided by pumped-storage hydroelectric systems, in which water is pumped from a lower elevation reservoir (at off-peak times, when the generation cost is lowest) to a higher elevation. Subsequently, at peak times, water is released back through a turbine, generating electricity when it is especially valuable. Other storage technologies that are less extensively used and are of much smaller scale include compressed air systems, batteries, and flywheels. These technologies can be important in certain applications such as renewables integration, avoiding T&D investment, and providing backup power.

Conventional hydroelectric generators can perform some storage functions. Pondage hydro (hydro with dams) can store water for later release and is used to provide reserves and to shave peak load. Within engineering and environmental considerations (flood control, 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. This time-shifting is a form of storage. Hydro facilities can also be used to actively store intermittent renewable energy. The Bonneville Power Administration (BPA) provides a service, which uses its vast hydro resources to support intermittent renewables. Under the "storage and shaping" service BPA receives intermittent output and, at a later time, provides shaped on- and off-peak energy.[36]

While storage is not an extensive part of today's electric infrastructure, it holds promise if gains in cost effectiveness can be realized. A defining characteristic of electric systems is that the level

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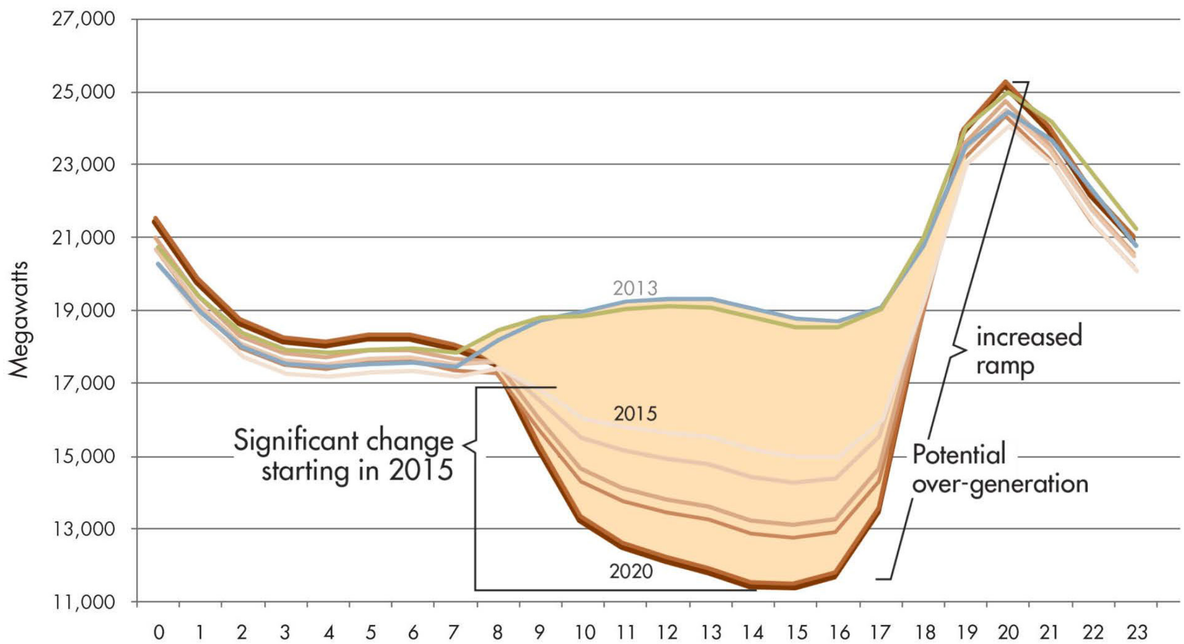
34 PG&E, News Releases, PG&E's Smart Grid Delivers Customer Benefits and Improved Reliability: Annual Report Details Utility's Application of 21st Century Technology to the Electric Grid, October 1, 2014, online at http://www.pge.com/en/about/newsroom/newsdetails/index.page?title=20141001_pges_smart_grid_delivers_customer_benefits_and_improved_reliability.

35 DOE, DOE Global Energy Storage Database, online at http://www.energystorageexchange.org/

36 White Creek and Nine Canyon wind farms factsheet, Bonneville Power Administration, December 2006, online at http://www.bpa.gov/news/pubs/FactSheets/fs200612-White%20Creek%20and%20Nine%20Canyon%20wind%20farms.pdf

of demand can change greatly over the course of a day and over the course of a year. One example of daily load variation is provided in Figure 12; the figure demonstrates that the daily load variations and ramping requirements in the California ISO are significant as of 2013 and projected to become more challenging as distributed generation (discussed in greater detail below) becomes more prevalent. These load variations mean that some portion of the system's generating capacity has to be designed and operated for flexibility rather than maximum efficiency. A cost-effective storage technology would effectively allow for flattening of load variations on the power grid, with the possibility of significant benefits in terms of resource adequacy and system reliability.

Figure 12
Projected Net Load in California ISO, 2013–2020



Source: Rothleder, Mark, "Long Term Resource Adequacy Summit" California ISO presentation, February 26, 2013. Available at: http://www.caiso.com/Documents/Presentation-Mark_Rothleder_CaliforniaISO.pdf

5. End-Use Infrastructure

Ultimately, the electric system exists to serve load, or the demand for electric services, from the residential, commercial, industrial, and transportation sectors. Accordingly, the infrastructure that consumes this electricity is also part of this system. The efficiency and usage patterns associated with end-use infrastructure are thus key drivers of the infrastructure needed to ensure the reliability and meet the other goals for the country's electric system. In 2012, the residential sector accounted for roughly 37% of the country's retail sales (in terms of MWh), while commercial and industrial demand accounted for approximately 36% and 27% respectively. Transportation-related sales were less than 0.2% of total sales.[37]

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[37] U.S. Energy Information Association, *EIA Electric Power Annual 2012*, December 2013, Table 1.2. Available at http://www.eia.gov/electricity/annual/pdf/epa.pdf

The largest uses of electricity, in terms of annual energy consumption, are industrial processes (roughly 21% of all electricity consumption) followed by lighting and space cooling (accounting for roughly 14% and 12%, respectively, of all electricity consumption).[38] However, peak demand levels are more important from an infrastructure design perspective, and the share of peak demand attributed to various end-use categories may vary substantially from annual energy consumption shares. For example, data from California in 2001 indicate that residential and commercial air conditioning together accounted for roughly 8% of total annual electricity consumption, but accounted for 28% of peak demand.[39] The end-use infrastructure also includes appliances such as water heaters, space heaters, refrigerators, and consumer electronics in residences, as well as office equipment and ventilation systems in commercial buildings.

6. Operational Structure

A full discussion of the day-to-day operational structure of the electric industry is beyond the scope of this report, and several details will depend on factors that are discussed later in this chapter. Two areas that will not be discussed in this report are resource planning, which is done in several different ways depending on state regulation and market rules (where they exist), and maintenance planning and coordination. This section discusses two important aspects that are relevant for understanding the discussion of the electric infrastructure that follows.

a. Centralized Dispatch

The primary mechanism that links the operation of the generation and transmission systems in bringing power to meet load is the process of centralized dispatch. Both in parts of the country characterized by a single vertically-integrated utility (though with many distribution-only public power and cooperatives in their midst) and bilateral wholesale markets, and in those regions characterized by centrally –organized wholesale markets, the safe and reliable delivery of power requires a system operator. The system operator's role is to coordinate the use of the available generation and transmission resources at their disposal to ensure the reliable delivery of power, with the goal of doing so in an economically efficient manner. In other words, regardless of the ownership of generation and transmission resources, the minute-to-minute decision of whether and how much of a given asset is used is made by a grid or system operator.

A dispatchable resource can have its power output adjusted within a range (thermal resources, hydro, biomass, and geothermal for example), and is often controlled directly by the system operator. Some resources, such as wind and solar, have variable outputs that are not known in advance with the same level of precision and predictability for other resources. A great deal of work has been done in recent years to predict output for wind and solar, but there is still forecast

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38 Calculations by The Brattle Group, based on EIA data.

39 Bender, Sylvia, Cheri Davis, Kae Lewis, *et al.*, Energy Efficiency and Conservation: Trends and Policy Issues. Prepared in Support of the *Public Interest Energy Strategies Report* under the Integrated Energy Policy Report Proceeding, California Energy Commission Docket 02-IEP-01. Publication 100-03-008F. May 2003. Available at http://www.energy.ca.gov/reports/2003-05-29_100-03-008F.PDF

uncertainty that the system operators must deal with. Both conventional generation and storage systems can help smooth out the variability of some of these resources.

The process of centralized dispatch involves several related steps, though on different time frames. The first is the advanced scheduling of resources in order to meet forecasted load. This is typically done at least a day in advance and is refined until the actual time of delivery. The second step is the dispatch of generating units to meet expected demand, and the second-by-second balancing of supply and demand. The third is the reservation and commitment of resources, not necessarily for generating or transmitting power, but that can be called upon to match short-term variations in demand and supply. Demand is constantly changing as customers vary the use of end-use equipment. Supply also varies as units experience outages and as the output of intermittent renewable generation (wind and solar) fluctuates. The power system must be able to follow these short-term, sub-hourly variations. The suite of services used for this short-term balancing is referred to as ancillary services, discussed in further detail below.

b. Ancillary Services

Ancillary Services (AS) "support the reliable operation of the transmission system as it moves electricity from generating sources to retail customers."[40] AS are furnished by a combination of generation and transmission facilities, but ultimately the system operator is responsible for ensuring that there are adequate AS at all times. AS are critical for reliability. Because generation and load must be matched in real time, the grid must have the ability to adjust generation levels very quickly. Customer demand is constantly varying, generators are not 100% reliable and sometimes fail unexpectedly, and wind and solar renewable resources have time-varying output that cannot be predicted with the same precision as dispatchable power. In addition to matching supply (generation) with demand, voltages must be maintained within tight tolerances at all points on the grid.

There are two types of power. "Real power" is the power available for performing useful work, such as producing heat or light, and "reactive power" is the power that must be supplied to maintain voltages throughout the system. The mix of both types of power is managed by capacitive and inductive devices in the transmission circuits, and by generators.[41] Generators are the principal source of both active and reactive power, producing both at the same time. For a given amount of real power a generator can produce a range of reactive power. This range is type and design specific.

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40 PJM, Markets & Operations, Ancillary Services. Available at http://www.pjm.com/markets-and-operations/ancillary-services.aspx.

41 See Graves, Frank C., "A Primer on Electric Power Flow for Economists and Utility Planners, TR-104604, EPRI," prepared by Incentives Research Project 2123-19, Final Report, Inc., for Electric Power Research Institute, February 1995. Available at http://www.epri.com/search/Pages/results.aspx?k=A%20Primer%20on%20Electric%20Power%20Flow%20for%20Economists%20and%20Utility%20Planners.

The table below defines the AS products commonly procured by operators in the U.S. for maintaining the reliability of the electric power system. Each RTO, Independent System Operator (ISO), or transmission provider has a set of services that fall into these categories. While there are regional differences in how ancillary services are described and also provided, each category is critical to the operation of the grid. Voltage control is done by adjusting the reactive power output of generators and adjusting transmission system components to inject or withdraw reactive power on a second-by-second basis.

Frequency response and regulation AS categories balance real power. Frequency response operates over a 0–30 second timeframe and is provided by generators' automatic response to frequency changes. Regulation functions over the four second to five minute timeframe and is usually furnished by units equipped with Automatic Generation Control. These units respond to signals from the system control room to increase or decrease output. Storage systems can also provide regulation. Most storage systems are better suited to provide regulation than conventional generators since they can be moved more quickly and accurately than conventional generators. The FERC recognized that the way in which regulation was compensated was inadequate, and in Order 755 required compensation for regulation services to take into account a resource's speed and accuracy.[42] These and the remaining AS categories are summarized in Table 3.

[42] 137 FERC ¶ 61064, 18 CFR Part 35, issued October 20, 2011. Available at http://www.ferc.gov/whats-new/comm-meet/2011/102011/E-28.pdf

Table 3
Categories of Ancillary Services

Services	Service Description	Response Speed
Voltage control	The injection or absorption of reactive power to maintain transmission-system voltages within required ranges	Seconds
Frequency Response	Power sources that online and able to automatically respond to changes in frequency	0 to 30 seconds
Regulation	Power sources online, on automatic generation control, that can respond rapidly to system-operator requests for up and down movements; used to track the minute-to minute fluctuations in system load and to correct for unintended fluctuations in generator output	4 seconds to 5 minutes
Spinning reserve	Power sources online, synchronized to the grid, that can increase output immediately in response to a major generator or transmission outage and can reach full output usually within 10 min	10 minutes to 105 minutes
Non-spinning reserve	Same as spinning reserve, but need not respond immediately; units can be offline but still must be capable of reaching the committed output level within the required time	10 minutes to 105 minutes

Source: Table derived from parts of NERC, Ancillary Services Matrix, http://www.nerc.com/docs/pc/ivgtf/NERC_ancillary_services%20ERCOT%20IESO%20NYISO%20MISO%20PJM%20SPP%20WECC%2012%2014.pdf

E. Market Structure

The regulatory structures laid out above have in turn shaped the market structures that provide many of the incentives influencing the future development of the electric infrastructure.

1. FERC Orders (Nos. 888, 889) Requires Open Access to Transmission

FERC Orders Nos. 888 and 889[43], issued in April 24, 1996, as FERC's answer to the Energy Policy Act of 1992 requirement for non-discriminatory access to transmission, drastically altered the landscape, with profound implications for the generation, transmission, and distribution of electricity throughout North America. These orders allowed for the separation of wholesale and retail operations from transmission services. Specifically, Order No. 888 ensured fair access to transmission resources, in part by requiring utilities to file an open-access transmission tariff

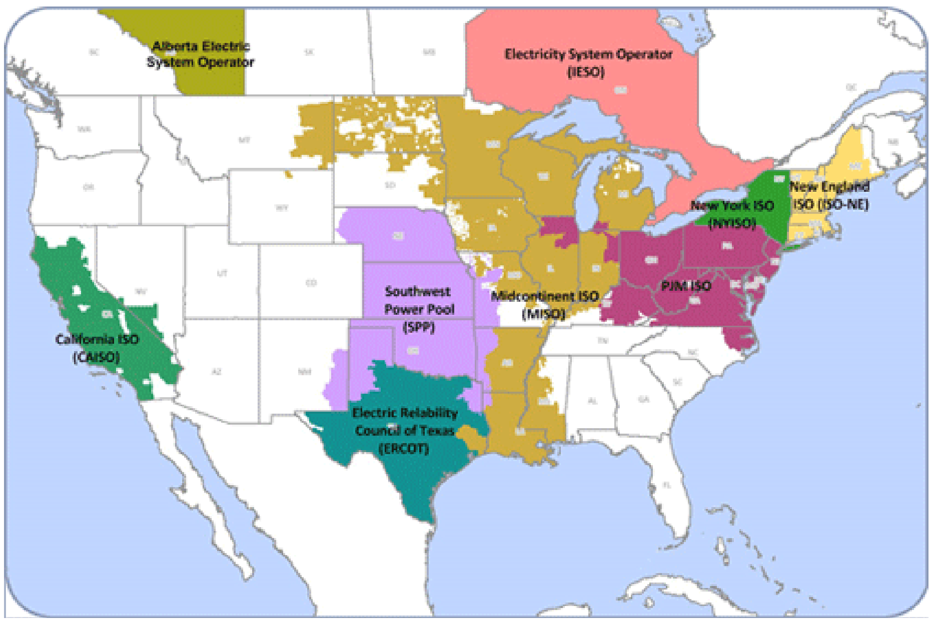
[43] See further information on the FERC orders at: http://www.ferc.gov/legal/maj-ord-reg.asp

(OATT). Order No. 889 was more concerned with specifying how participants in the wholesale electricity markets would interact and exchange information with transmission owners. These orders provide the framework upon which centrally-organized wholesale markets and, in restructured states as discussed above, retail markets have been created.

2. RTOs/ISOs in Part of the Country

FERC Order No. 2000, issued on December 29, 1999, built on Orders 888 and 889, with the intent of establishing organizations alternatively known as Regional Transmission Organizations (RTOs) or Independent System Operators (ISOs).[44] These organizations, of which there are nine in North America, are depicted in Figure 13.

Figure 13
Regional Transmission Organizations and Independent System Operators



Source: FERC, Regional Transmission Organizations (RTO)/Independent System Operators (ISO), July 2014. Downloaded from http://www.ferc.gov/industries/electric/indus-act/rto.asp

The auction-based energy and AS market mechanisms used by the RTO/ISOs are designed to ensure that load within that RTO/ISO is met with adequate generation at the lowest overall system cost, subject to transmission and generation constraints. Potential suppliers of electricity and AS offer their supply by submitting bids to the market operators, who rely on complex software and algorithms to meet demand at every point in the transmission grid. Relative to a market that is dominated by bilateral trades, this structure theoretically lowers transaction costs and increases the extent to which generators within an ISO/RTO compete with one another.

[44] RTOs and ISOs differ slightly in that RTOs meet additional requirements and have greater responsibility for the transmission network. However, the distinction is not crucial to this overview of market structure, and much of the industry uses the two terms interchangeably. It is worth noting that several of the existing ISOs/RTOs evolved from organizations established long before Order 2000.

In addition to coordinating and controlling the electric transmission grid (usually, but not always, encompassing several balancing authorities), RTOs and ISOs act as independent operators, therefore guaranteeing open non-discriminatory access to transmission, of the large regional wholesale electric markets defined by their borders. Other responsibilities include administering transmission tariffs and pricing systems, managing transmission congestion with market mechanisms, and planning transmission additions and upgrades.

Most RTOs also have what are known as capacity requirements that companies that serve load (sometimes called load serving entities or LSEs) have arrangements for sufficient capacity to serve their load.[45] These requirements can either be met by bilateral agreements with generators or by purchases from formal "capacity markets." The exception to this in the U.S. is Texas, which by law does not have a formal capacity requirement, but does have other market mechanisms intended to ensure generation adequacy.[46]

3. Non-RTO Regions

In regions that are not part of an RTO/ISO the BAs are usually vertically integrated utilities that are responsible for distribution, transmission, and generation. IPPs located in these regions operate under the BAs' open access tariffs, have access to the transmission system, and can sell power within the region or outside of the region. Embedded in these regions are many much smaller publicly- and cooperatively-owned distribution-only electric utilities. Sales within these regions are typically on a bilateral basis since there is no centralized wholesale market.

4. Regional Seams—Physical and Economic

The boundary between balancing authority areas is referred to as a seam. The RTOs coordinate operations and unit dispatch within their boundaries. Each of the RTOs also operates centralized markets for energy and ancillary services. Seams reduce the overall efficiency in three ways:

1. There are charges to move power across a seam.
2. Unit commitment inefficiencies result in less than least-cost unit dispatch across balancing authority areas.

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45 Pfeifenberger, Johannes, Kathleen Spees, Kevin Carden, Nick Wintermantel, Resource Adequacy Requirements: Reliability and Economic Implications, prepared by The Brattle Group and Astrape Consulting for Federal Energy Regulatory Commission, September 2013. Available at: http://www.brattle.com/system/publications/pdfs/000/004/984/original/Resource_Adequacy_Requirements_Pfeifenberger_Spees_FERC_Sept_2013.pdf

46 Newell, Sam, Kathleen Spees, Johannes Pfeifenberger, Robert Mudge, Michael DeLucia, and Robert Carlton, *ERCOT Investment Incentives and Resource Adequacy*, prepared by The Brattle Group for ERCOT, June 1, 2012 ("Brattle ERCOT RA Report"), available at http://www.brattle.com/system/publications/pdfs/000/004/820/original/ERCOT_Investment_Incentives_and_Resource_Adequacy_Newell_Spees_Pfeifenberger_Mudge_ERCOT_June_2_2012.pdf?1378772132.

3. Congestion management is not perfectly coordinated.

The charges to move power across seams are sometimes referred to as "wheeling charges." These charges are listed in each balancing authority's Open Access Transmission Tariff.

Each balancing authority commits and dispatches with less than perfect knowledge and accounting for neighboring systems. For example, PJM might commit high-priced peaking units in northern Illinois, when MISO has low-cost gas units in southern Illinois that go unutilized even though there are no transmission constraints that might have prevented a MISO to PJM transfer.[47]

Unit dispatch in one balancing authority affects power flows in neighboring balancing authorities. As a result neighboring ISOs sometimes coordinate the interfaces or flowgates between them. As an example, PJM and MISO coordinate the QuadCities-Cordova flowgate between their systems.

The FERC, RTOs and utilities recognize that seams are impediments to trade and cause congestion. There are numerous initiatives to reduce the impact of seams, including seams coordination agreements and market-to-market coordination and management efforts.[48]

F. Electric Sector Trends

1. Projections of Future Generation Needs

The Energy Information Administration's Annual Energy Outlook 2014 (AEO2014) provides projections, through 2040, of several key indicators for the electric sector, under many different sets of assumptions.[49] This section provides a review of five AEO2014 cases that have important implications for the electric infrastructure, and particularly the transmission system, over the next 25 years. These cases are:

- The Reference Case
- The High Oil and Gas Resource case
- The Low Oil and Gas Resource case
- The No Sunset case
- The GHG25 case

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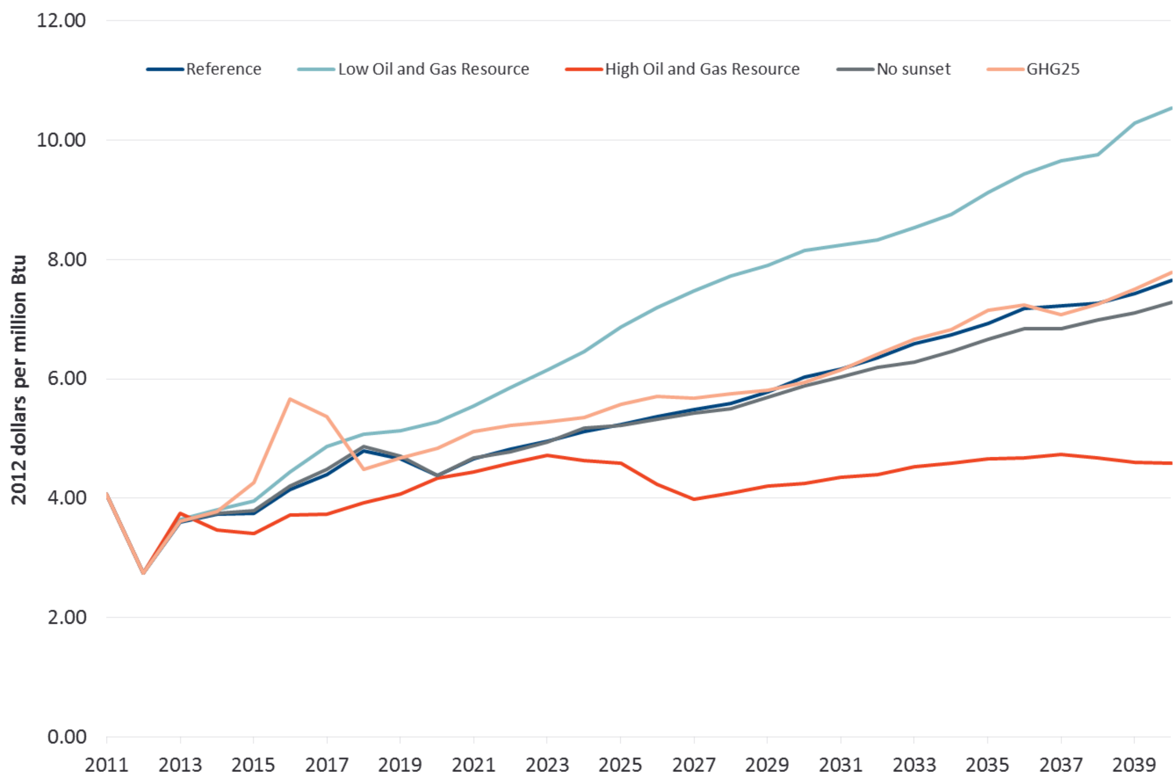
47 Paul Ciampoli, *FERC Examines Seams Coordination Between MISO and PJM*, Public Power Daily, January 27, 2015. http://www.publicpower.org/media/daily/ArticleDetail.cfm?ItemNumber=43054#sthash.vwCy1vQb.dpuf

48 See, *e.g.*, Midcontinent Independent System Operator, Seams, online at https://www.misoenergy.org/WhatWeDo/StrategicInitiatives/Pages/Seams.aspx.

49 http://www.eia.gov/forecasts/aeo/

The Reference case considers only the current set of enacted state and federal policies (*i.e.*, only laws and regulations that are enacted or final) and the EIA's expectation for fuel supply. The High Oil and Gas Resource case assumes significantly more oil and gas is available from shale resources in the U.S. than in the Reference case, which leads to lower oil and gas prices. The Low Oil and Gas Resource case assumes significantly less oil and gas is available from shale resources in the U.S. than in the Reference case, leading to higher oil and gas prices. The No Sunset case assumes a continuation of the production tax credits for renewables that expired at the end of 2013 and an indefinite extension of the 30% investment tax credit for solar. The GHG25 case assumes an economy-wide carbon dioxide emissions fee of $25 per metric ton in 2015 (in 2012 dollars) escalating by 5% per year in real dollar terms to about $85 per metric ton in 2040. These cases have very different implications for the long-term development of the electric system. Figure 14 shows the natural gas price trajectories in each of the cases, ranging from $4–8/MMBtu in 2030.

Figure 14
Henry Hub Natural Gas Prices



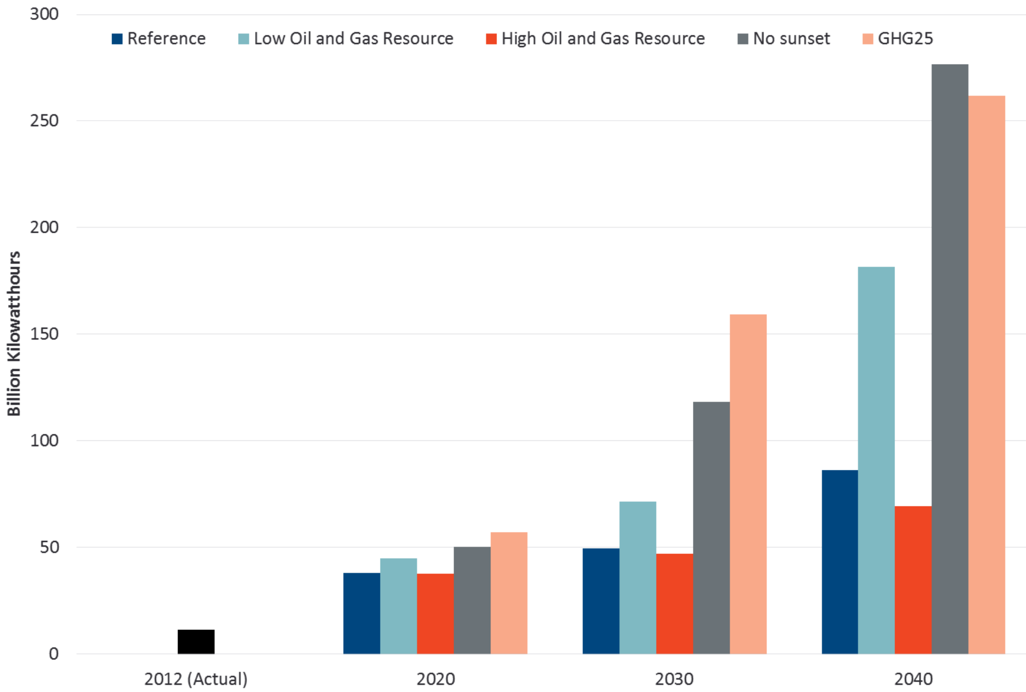
Source: EIA, *Annual Energy Outlook 2014 with projections to 2040,* DOE/EIA-0383(2014), April 2014. Available at: http://www.eia.gov/forecasts/aeo/.

a. Renewables

The Reference case has no national carbon policy, only current state RPS standards and the baseline view of oil and gas resources, which limits the growth of wind and solar until gas prices rise to levels at which renewables can compete with gas-fired plants without the PTC or ITC. As shown in Figure 15 and Figure 16, the High Oil and Gas Resource case shows very little renewables growth since gas prices never rise to the levels at which renewables are competitive in most regions, whereas the Low Oil and Gas Resource case has significant growth in renewables beginning around 2030.

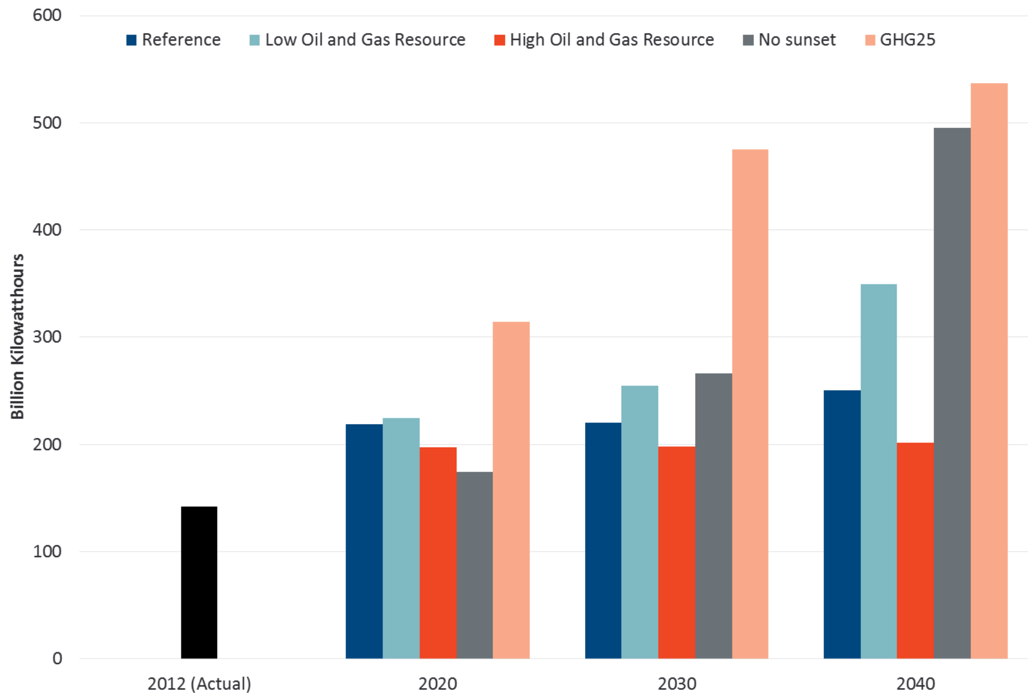
The No Sunset and the GHG25 cases both have strong long-term growth in renewables (considering only wind and solar). Between 2012 and 2040, the GHG25 case has a 500% increase in energy from renewables and the No Sunset case has a 400% increase.

Figure 15
Projected Wind Generation



Source: U.S. Energy Information Administration (EIA), *Annual Energy Outlook 2014 with projections to 2040,* DOE/EIA-0383(2014), April 2014. Available at: http://www.eia.gov/forecasts/aeo/.

Figure 16
Projected Solar Generation



Source: U.S. Energy Information Administration (EIA), *Annual Energy Outlook 2014 with projections to 2040,* DOE/EIA-0383(2014), April 2014. Available at: http://www.eia.gov/forecasts/aeo/.

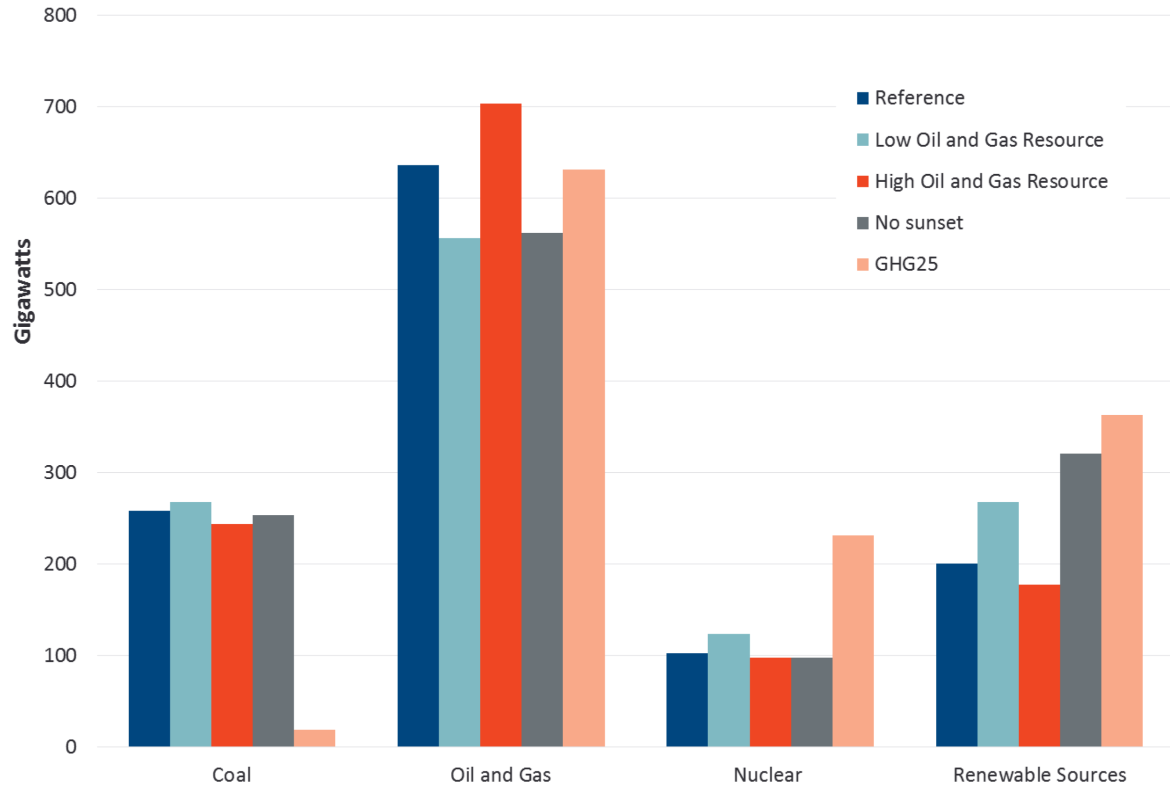
b. Other Technologies

The long-term mix of generation beyond renewables also varies across the cases, as shown in Figure 17. However, all cases include natural gas-fired generation as the dominant type of new capacity over the long run. Relative to the Reference case, the Low Oil and Gas Resource Case leads to somewhat more renewables, somewhat more nuclear, and fewer coal plant retirements. The High Oil and Gas Resource Case leads to fewer renewables and somewhat more coal plant retirements, again relative to the Reference case.

The No Sunset case has significantly more renewables by 2040 (about 120 GW) and 74 GW less natural gas, relative to the Reference case. Due to the intermittent nature of renewables, the No Sunset case has 34 GW more *total* capacity than the Reference case in 2040.

The GHG25 case shows a very dramatic change in the long-term generation mix. By 2040, there is nearly twice as much renewable capacity, and more than twice as much nuclear capacity than in the Reference case. Altogether, nuclear and renewables make up about half of the 2040 installed capacity in the GHG25 case, while they constitute only a quarter of the 2040 installed capacity in the Reference case. This has important implications for the transmission system since both renewables (especially onshore wind) and nuclear tend to be built in locations that are remote from load, whereas combined-cycle plants are generally built closer to load centers.

Figure 17
Projected Capacity Additions, through 2040



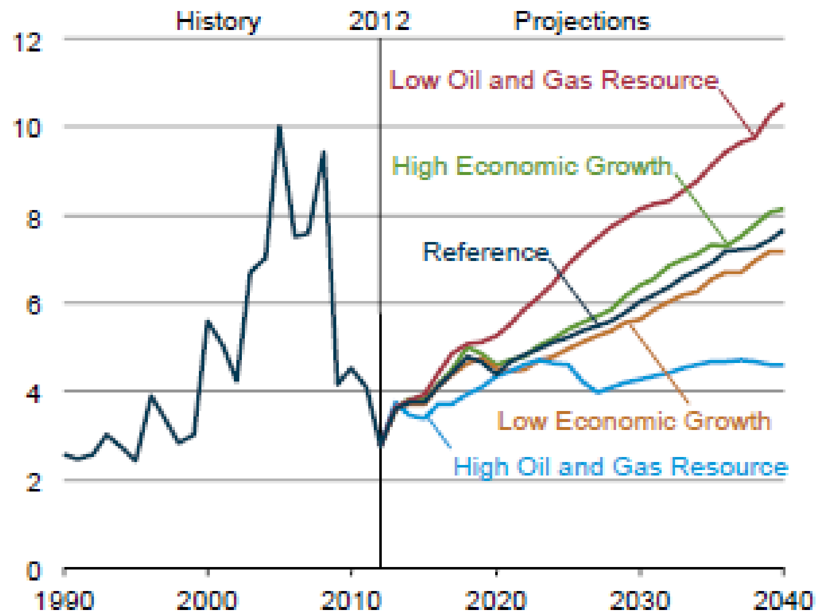
Source: EIA, *Annual Energy Outlook 2014 with projections to 2040,* DOE/EIA-0383(2014), April 2014. Available at: http://www.eia.gov/forecasts/aeo/.

2. Gas Prices and Resources

Gas-fired generation capacity increased significantly in the 2000s, as shown in Figure 6 above. In the mid to late 1990s, tightening reserve margins created a need for new capacity in many parts of the country. The combination of short-lead times to construct, relative ease of permitting, and low natural gas prices made Natural Gas Combined-Cycles (NGCCs) the lowest-cost option to serve load. As a result, NGCCs were rapidly constructed throughout the country. NGCCs have fewer harmful emissions than coal plants and can be sited much closer to load centers. In some cases, the NGCCs were built close to load to relieve congestion, reducing the need for transmission upgrades.

While natural gas prices were relatively low during the 1990s, between 2000 and 2008 prices averaged two to three times higher than in the previous decade. Price volatility also increased. However, by this time many NGCC units were under construction or well along in the development cycle. These NGCCs had been intended to provide baseload generation, but at the higher natural gas prices NGCCs were not a cost-competitive source of baseload generation relative to coal plants. As a result, NGCC capacity factors[50] were lower than planned.[51] Natural gas prices reached their peak in 2008 before falling back due to the recession and the large and growing shale gas resource base, as shown in Figure 18.

Figure 18
Annual average Henry Hub spot prices for natural gas in five cases, 1990–2040 (2012 dollars per million Btu)



Source: U.S. Energy Information Administration (EIA), *Annual Energy Outlook 2014 with projections to 2040,* DOE/EIA-0383(2014), April 2014, Figure MT-41. Available at: http://www.eia.gov/forecasts/aeo/.

After the gas price collapsed in 2008, the operation of these plants increased significantly as NGCC generation replaced high cost coal units, as shown in Figure 19.

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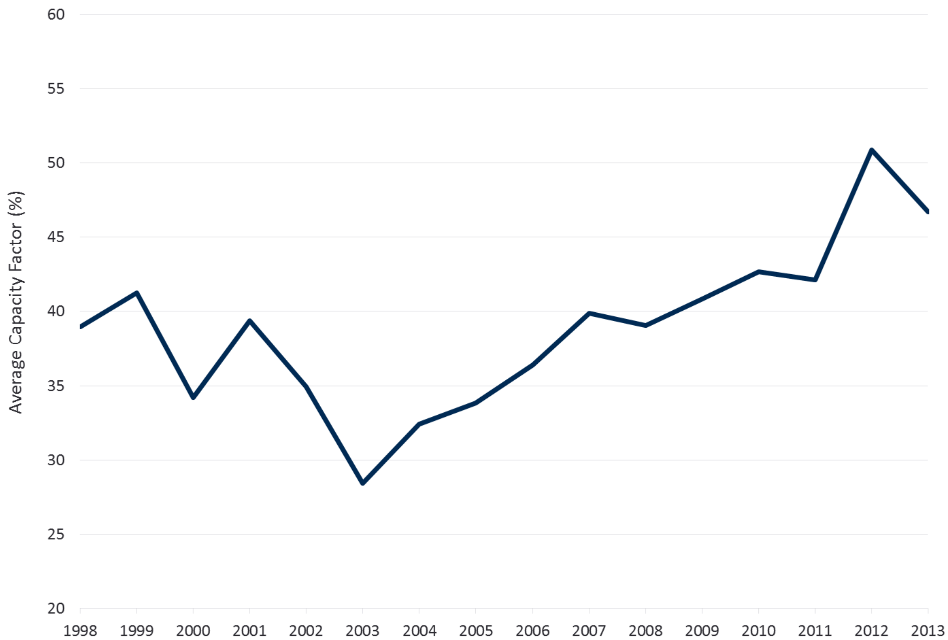
50 The capacity factor of a generation unit is a measure of how highly utilized it is. For example, a natural gas combined cycle unit might be out of service 10% to 15% of the year for maintenance and repairs. If the unit were to operate at full capacity at all other times, its annual capacity factor would be 85% to 90%

51 MIT Interdisciplinary Study on The Future of Natural Gas, June 2011, available at http://mitei.mit.edu/system/files/NaturalGas_Report.pdf.

Figure 19
Average Capacity Factor of Combined Cycle Power Plants in the US (Capacity Weighted)



Source: SNL Financial.

The increased reliance on natural gas generation in a few areas of the U.S., such as New England and PJM, has resulted in concerns over the security of supply during winter months when the demand for natural gas-based heating is at its peak. Thus, there has been increased attention to the coordination of the gas and electric sectors in committing and scheduling gas and electricity deliveries. The North American cold wave ("polar vortex") of early 2014 further emphasized the potential severity of the issue when several regional markets came close to failing to meet their electricity needs due to gas delivery problems. Market operators in the Eastern Interconnection, where gas pipeline constraints have been the most prevalent, have begun to adapt their markets to account for this additional concern.[52] Gas supply problems were also contributing factors to outages in ERCOT during a period of lower than normal temperatures in February 2011.[53] Looking forward, it is likely that more gas-fired generation will be built as some coal units retire.

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[52] ISO-New England, having experienced two consecutive winters in which gas pipeline constraints resulted in limits in gas-fired generation, has filed for changes to their Forward Capacity Market (FCM) that provide incentives for performance during all hours in which capacity to meet load is limited, which are referred to as Pay for Performance (PFP) incentives. The incentives have been designed to ensure that back-up fuel supply, such as ultra-low sulfur diesel (ULSD), is available for dual-fuel operation of gas-fired generation units.

PJM, after experiencing similar issues in 2014, has proposed additional market rules for providing similar incentives.

[53] Black & Veatch, Gas Curtailment Risk Study, Prepared for the Electric Reliability Council of Texas, March 2012. Available at: http://www.ercot.com/content/news/presentations/2012/BV%20ERCOT%20Gas%20Study%20Report%20March%202012.pdf

Additional gas generation is expected to be built at locations with access to natural gas pipelines. As shown in Figure 18, there is significant uncertainty in future natural gas prices.

The implications of increased reliance on gas generation are not yet clear on future transmission needs. Existing transmission planning processes do not yet consider any fuel constraint-related generation outages. However, to the extent that gas-fired generation becomes the dominant baseload generation resource in most parts of the country, future transmission planning process and system reliability criteria would be wise to take those contingencies into account.

There has been considerable concern about this issue over the last few years. It has and is being studied by NERC, FERC, RTOs, and state and utility planning collaboratives.[54]

3. Coal Plant Retirements

Where delivered gas prices have been low enough to induce significant generation competition between gas and coal generation, the operating margins of coal plants, particularly the older and less efficient ones, have decreased dramatically. As discussed above, coal generation faces a series of environmental regulations that will require plant owners to make decisions about whether to retrofit or retire the units. Analysis of future retirement decisions has led to estimates of 59–77 GW of additional retirements with 11–16 GW of retirement expected in MISO and 14–21 GW in PJM.[55, 56] There are more recent estimates since these were made, with actual announced retirements continuing to evolve. While environmental regulations are a key driver of retirements, retirements are also driven by low gas prices.[57, 58]

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54 See, *e.g.*, NERC, *2013 Special Reliability Assessment: Accommodating an Increased Dependence on Natural Gas for Electric Power, Phase II: A Vulnerability and Scenario Assessment for the North American Bulk Power System*, May 2013. Available at http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_PhaseII_FINAL.pdf. Also, Babula, Mark, Eastern Interconnection Planning Collaborative's (EIPC) Gas-Electric System Interface Study: ISO-New England Project Update, presentation, August 14, 2014. Available at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2014/aug142014/a3_eipc_update.pdf.

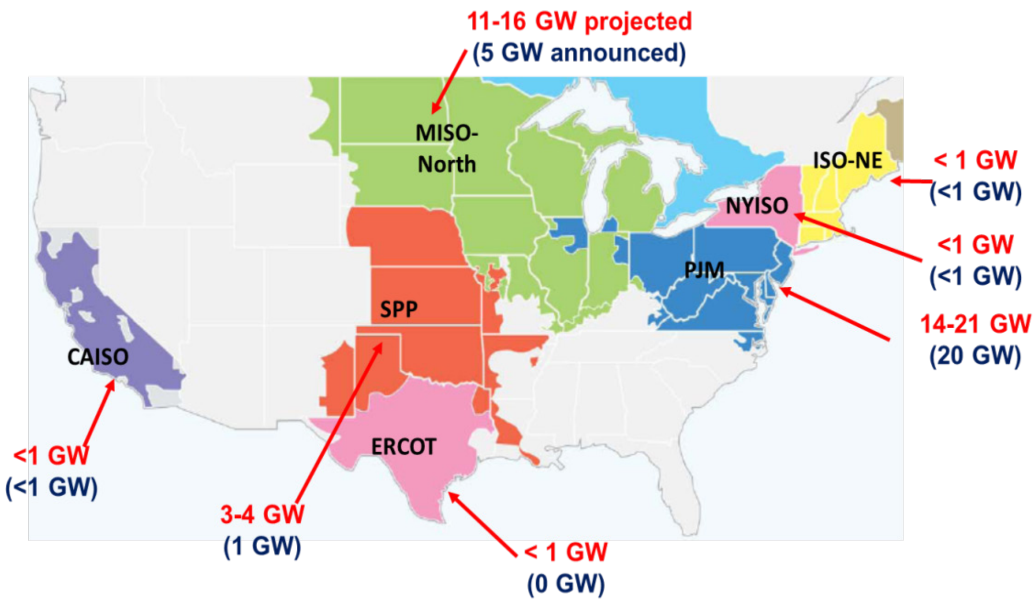
55 Celebi, Metin, Frank Graves, and Charles Russell, "Potential Coal Plant Retirements: 2012 Update," The Brattle Group Discussion Paper, October 2012. Available at http://www.brattle.com/system/publications/pdfs/000/004/678/original/Potential_Coal_Plant_Retirements_-_2012_Update.pdf?1378772119.

56 EPA V5.13 Base Case.

57 Aydin, Onur, Frank Graves, and Metin Celebi, "Coal Plant Retirements: Feedback Effects on Wholesale Electricity Prices," The Brattle Group Discussion Paper, November 2013. Available at http://www.brattle.com/system/publications/pdfs/000/004/966/original/Coal_Plant_Retirements_-_Feedback_Effects_on_Wholesale_Electricity_Prices.pdf?1386628227.

58 EIA, *Annual Energy Outlook 2014 with projections to 2040,* DOE/EIA-0383(2014), April 2014. Available at: http://www.eia.gov/forecasts/aeo/.

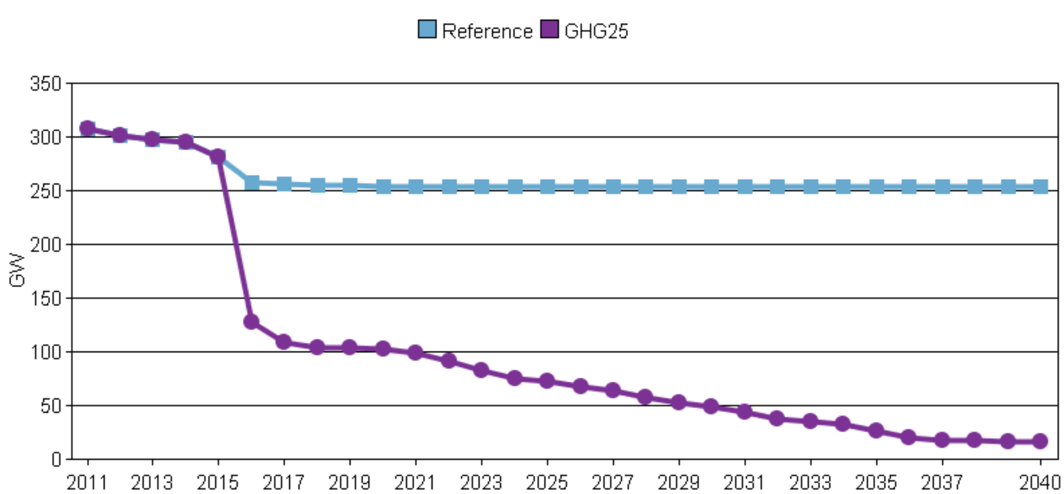
Figure 20
Projected Coat Plant Retirements through 2020



Source and notes: Aydin, Onur, Frank Graves, and Metin Celebi, "Coal Plant Retirements: Feedback Effects on Wholesale Electricity Prices," The Brattle Group Discussion Paper, November 2013. Coal retirements in the non-RTO regions in the southeast are projected to be approximately 30 GW and in the non-CAISO WECC region are expected to be approximately 2–5 GW. The announced coal retirements in CAISO was corrected from the original. Entergy (operating in AR, LA, TX, and MS) has since joined MISO to become "MISO South".

Proposed EPA greenhouse gas regulations could result in additional coal retirements. Figure 21 shows the coal-fired generation capacity in the AEO2014 Reference and GHG25 cases.

Figure 21
Coal Capacity in the AEO2014 References and GHG25 Cases



Source and notes: EIA, Annual Energy Outlook 2014 with projections to 2040, DOE/EIA-0383(2014), April 2014. Available at: http://www.eia.gov/forecasts/aeo/. In the other three cases discussed above, the coal capacity is very similar to that of the Reference case.

If coal plant retirements occur *en masse*, the implications for the existing transmission systems could be significant. System planners in several regions have already developed future scenarios that incorporate future coal retirements, as well as announced retirements and have begun to use those forecasts to plan for future transmission needs, including in some regions such as PJM needed near-term new transmission lines to maintain reliability.

While gas deliverability has recently been an issue of focus in ensuring the reliability of generation capacity, coal inventories have been at historic lows due to limited railroad access caused by the increased usage of the rails for transporting crude oil from oil pipeline constrained regions, such as the Bakken basin in North Dakota and Montana. Coal plants that normally operate at maximum output for most of the year, and especially during high load months, have sometimes (but infrequently) experienced coal delivery problems that have reduced inventories at plants. A few companies experienced this type of problem in the summer of 2014 and operated coal plants at reduced capacity to ensure that they do not deplete their on-site coal supplies prior to future shipments.[59]

4. Nuclear Issues

Low natural gas prices have resulted in low energy prices and increased economic pressure on nuclear generation facilities. The loss of these plants could lead to different 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 NYISO analyzed the implications of shutting down the two Indian Point nuclear units and found that reliability violations would occur in 2016 if the Indian Point Plant retired.[60] The NYISO found that there would be potential deficiencies in power in New York City, violations of reliability criteria, and potentially voltage performance issues. The New York Public Service Commission approved a plan to add new transmission facilities and energy efficiency/demand response measures.[61]

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59 See, *e.g.*, http://www.platts.com/latest-news/coal/louisville-kentucky/kansas-co-op-sunflower-cuts-coal-plant-generation-21305722

60 New York Independent System Operator (NYISO), *2012 Reliability Needs Assessment: Final Report*, September 18, 2012. Available at http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Planning_Studies/Reliability_Planning_Studies/Reliability_Assessment_Documents/2012_RNA_Final_Report_9-18-12_PDF.pdf.

61 State of New York Public Service Commission, "Indian Point Contingency Plans Move Forward—PSC Details Plans to Ensure Grid Reliability and Safeguard Customers," Press Release, 13076/12-E-0503. Available at http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={1D2A3C42-9CAE-49AE-9E5B-0B2DABD0E015}

The closure of the two San Onofre nuclear units in southern California has resulted in local reliability problems for San Diego as well as local voltage problems.[62] The California ISO has approved a new transmission line with an in-service date of 2017 to support San Diego.

Not all nuclear plant shutdowns would result in the need for transmission upgrades or replacement generation. Following the shutdown of Dominion's Kewaunee nuclear plant in Wisconsin in 2013, MISO found no transmissions improvements were required to address the shutdown.[63]

5. Low Load Growth

Growth in U.S. electricity load (demand) is at the lowest levels of the last several decades as illustrated in Figure 22.[64] The low load growth is driven by policies that promote energy efficiency,[65] loss of much the U.S. industrial base over the last several decades to overseas locations and the related transition to a service economy,[66] much greater energy productivity in remaining industrial loads, recently the slow recovery from the 2007–2009 recession,[67] increases in distributed generation (particularly rooftop solar),[68] and fuel switching, as direct use of natural gas (as opposed to electricity fueled in part by natural gas) is decreasing demand for electricity.[69] This outlook has several possible implications. For example, existing utility business models may be insufficient to induce investment in distribution infrastructure, in part because the common practice is to rely on volumetric rates for residential customers to recover the cost of such investments. Volumetric rates combine transmission, distribution, and energy costs into a single rate based on delivered energy (cents/kWh). In reality, the only component that is truly

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[62] William A. Monsen and David N. Horwath, *Additional Power Needed In Southern California; Onofre Nuclear Generating Station (SONGS) And Expected Shutdown Of CA Coastal Power Plants*, Project Finance NewsWire, October 2013.

[63] Nelson, Gabriel and Hannah Northey, "Low electricity prices lead Dominion to decommission Wisconsin reactor," *Midwest Energy News*, October 23, 2012. Available at http://www.midwestenergynews.com/2012/10/23/low-electricity-prices-lead-dominion-to-decommission-wisconsin-reactor/

[64] Faruqui, Ahmad, "Surviving Sub-One Percent Sales Growth," presented at ACC Workshop, Phoenix, Arizona, The Brattle Group, March 20, 2014. Available at http://www.brattle.com/system/publications/pdfs/000/004/994/original/Surving_Sub-One_Percent_Growth_(03-20-14).pdf?1395350863.

[65] *Lower U.S. Electricity Demand Growth Would Reduce Fossil Fuels' Projected Generation Share,* EIA Today in Energy, April 30, 2014.

[66] Steven Nadel and Rachel Young, *Why Is Electricity Use No Longer Growing?, American Council for an Energy Efficient Economy,* February 2014.

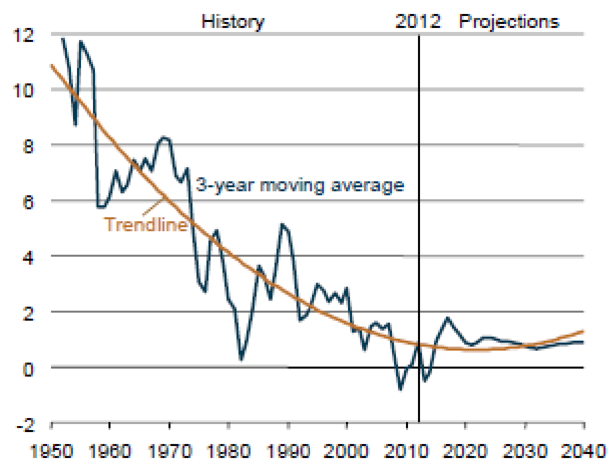
[67] Smith, R. "U.S. Electricity Use on the Wane." *The Wall Street Journal*, January 2, 2013.

[68] Peter Kind, *Disruptive Challenges: Financial Implications and Strategic Responses to a Changing Retail Electric Business,* The Edison Electric Institute, January 2013.

[69] Alan Krupnick, Zhongmin Wang, and Yushuang Wang, *Sector Effects of the Shale Gas Revolution in the United States,* Resource for the Future, July 2013.

volumetric is the variable cost of generating electricity; the cost of the wires to the house and the maintenance of those wires are largely fixed costs. If customers reduce load through efficiency measures and/or generate electricity using rooftop solar or another distributed generation technology, under volumetric rates they may avoid paying for some of the infrastructure that provides the electric service on which they rely. Those costs may then be shifted to other customers through higher variable rates. This set of circumstances has led some to question the long-term viability of the current IOU business model, or at least the long-term viability of the prevailing rate structure used by most IOU's.[70] On the other hand, utility loads would increase should there become a wide-spread adoption of electric vehicles someday. The implications of these trends are explored in further detail in the Distribution section.

Figure 22
U.S. Electricity demand growth in the Reference case, 1950–2040 (percent)

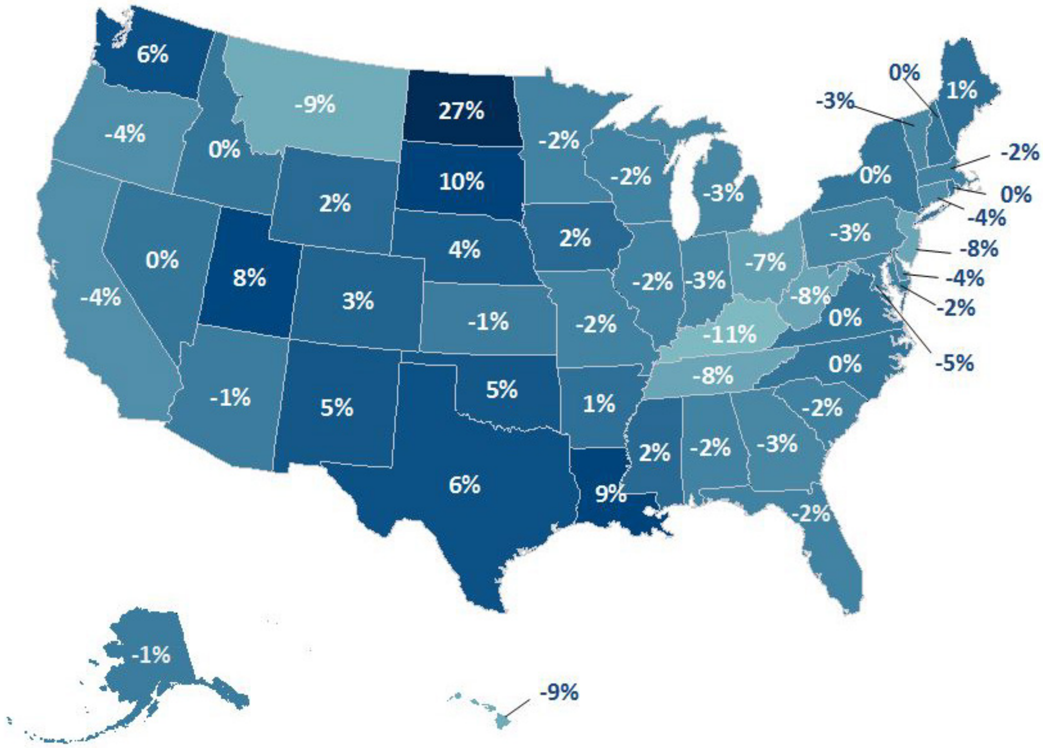


Source: EIA, *Annual Energy Outlook 2014 with projections to 2040,* DOE/EIA-0383(2014), April 2014, Figure MT-29. Available at: http://www.eia.gov/forecasts/aeo/.

It is important to note that while there is low load growth nationally, there is wide variation in the amount of load growth across states and regions, due to economic factors and differences in the other factors cited above. This variation is depicted in Figure 23.

[70] See, *e.g.*, Kind, Peter, *Disruptive Challenges: Financial Implications and Strategic Responses to a Changing Retail Electric Business*, prepared for the Electric Edison Institute, January 2013.

Figure 23
Percent Change in Retail Sales (kWh), Over the Period 2008–2013



Source: EIA, Retail Sales of Electricity: All Sectors 2013, accessed on September 23, 2014, online at: http://www.eia.gov/electricity/data/browser

6. Carbon Regulations

There are currently two regional GHG reduction policies in the U.S. The Regional Greenhouse Gas Initiative (RGGI) covers nine northeast states.[71] California has a state-wide policy under Assembly Bill 32.[72] EPA has also proposed rules that cover new and existing electric generation sources in all states. The most recent proposed rule (The Clean Power Plan) would impose state-specific carbon dioxide emission rates, but would allow states to form regional groups to lower overall compliance costs.[73]

Nationwide carbon regulations could completely transform the electric system. The climate goals defined by President Obama would make major changes to the generation mix and its

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71 Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont. See http://www.rggi.org/ for more details.

72 To review Assembly Bill 32 see Assembly Bill No. 32 CHAPTER 488, Approved September 27, 2006. Available at: http://www.leginfo.ca.gov/pub/05-06/bill/asm/ab_0001-0050/ab_32_bill_20060927_chaptered.pdf. For more information on the program, see the California Air Resource Board website: http://www.arb.ca.gov/cc/capandtrade/capandtrade.htm

73 See EPA's notices and technical documents for the Clean Power Plan here: http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule

supporting infrastructure (particularly transmission but also possibly distribution). Those goals include cutting net greenhouse gas emissions 26-28 percent below 2005 levels by 2025 and an 80% reduction in economy-wide greenhouse gas emissions by 2050.[74] These goals are similar to those that drove legislation that passed in the U.S. House of Representatives in 2009 (American Clean Energy and Security Act of 2009, H.R. 2454),[75] but that did not pass the Senate.

Making significant reductions in GHG emissions requires large scale de-carbonization of the economy. Studies done by EPA, Department of Energy, and many research groups show that the electric utility sector would likely provide a significant amount of the emissions reductions through a combination of zero or lower carbon resources[76]

- Fuel switching from coal to natural gas;
- Renewable generation;
- New nuclear plants or fossil plants (coal or gas) with carbon capture and sequestration;
- Improved heat rates at existing fossil units; and
- Energy efficiency.

Under a scenario where very large economy-wide reductions in total GHG emissions are required, electrification of the transportation sector is a likely option for reducing GHG emissions.

Carbon regulation would likely cause an expansion in intermittent renewable resources, *i.e.*, wind and solar. The best wind resources are located offshore or in parts of the Midwest and the Southwest.[77] The variation in wind resource quality can be seen in Figure 24 while the solar resource is depicted in Figure 25.

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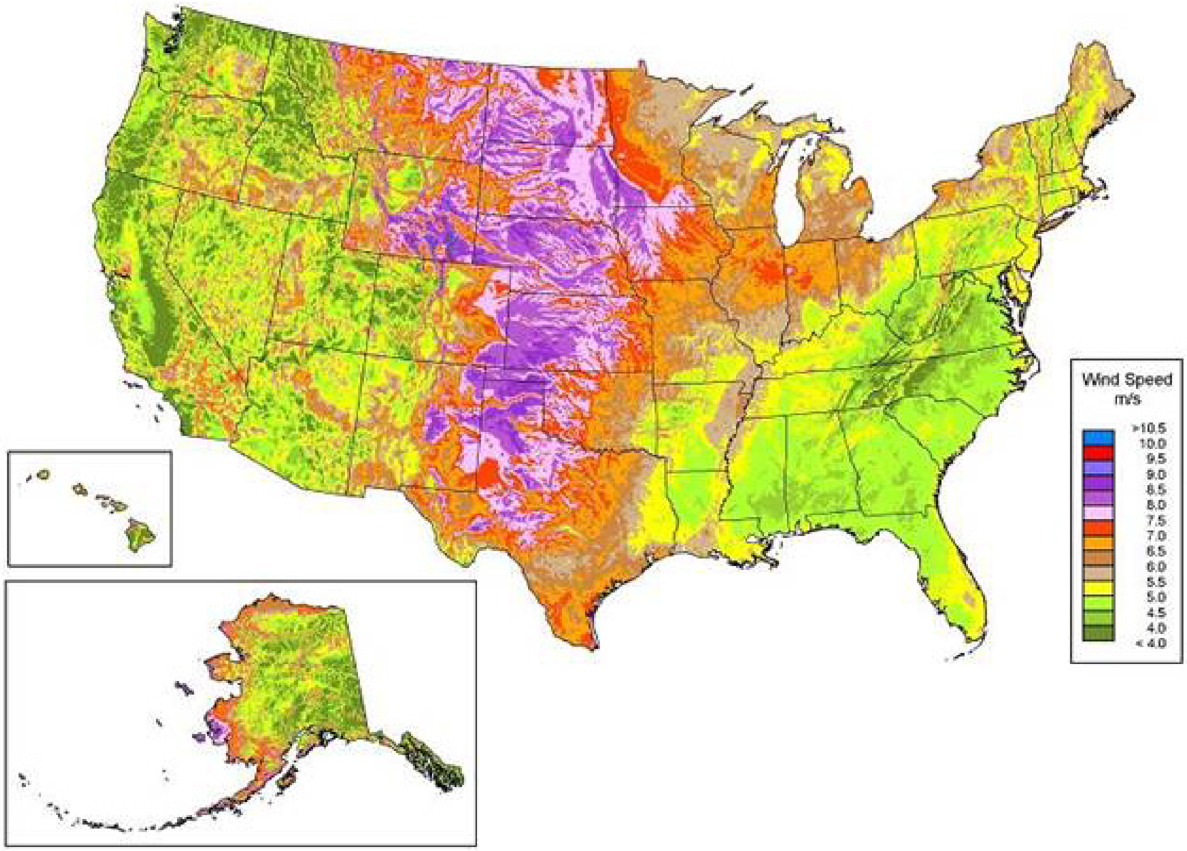
74 "FACT SHEET: U.S.-China Joint Announcement on Climate Change and Clean Energy Cooperation", Nov. 11, 2014 http://www.whitehouse.gov/the-press-office/2014/11/11/fact-sheet-us-china-joint-announcement-climate-change-and-clean-energy-c, as referenced in "Climate Change And President Obama's Action Plan", http://www.whitehouse.gov/climate-change

75 *'American Clean Energy and Security Act of 2009'*, 111th Congress 1st Session, available at: http://www.gpo.gov/fdsys/pkg/BILLS-111hr2454eh/pdf/BILLS-111hr2454eh.pdf

76 EPA's results from modeling the Clean Power Plan are downloadable from this site: http://www.epa.gov/airmarkets/programs/ipm/cleanpowerplan.html. See additional studies: *Remaking American Power Preliminary Results*, Center for Strategic and International Studies, July 24, 2014; David Pickles, Bill Prindle, Chris MacCracken, Steven Fine, and Phil Mihlmester, *EPA's 111(d) Clean Power Plan Could Increase Energy Efficiency Impacts, Net Benefits, and Total Value*, ICF International, 2017; David Harrison, Jr. and Anne E. Smith, *Potential Energy Impacts of the EPA Proposed Clean Power Plan*, NERC, October 2014.

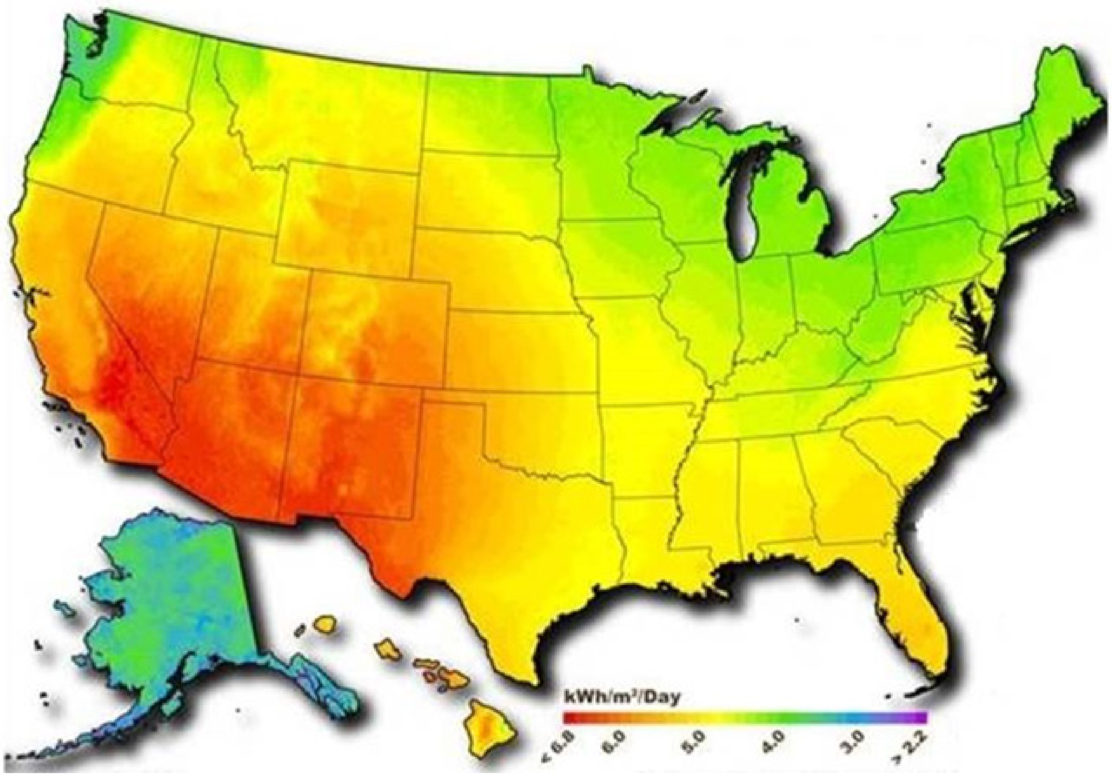
77 See a collection of NREL resource maps including onshore and offshore resources at: http://www.nrel.gov/gis/wind.html

Figure 24
Annual Average Wind Speed at 80 Meters



Source: National Renewable Energy Laboratory and AWS Truepower, United States – Annual Average Wind Speed at 80 Meters, April 1, 2011, online at http://www.nrel.gov/gis/images/80m_wind/USwind300dpe4-11.jpg

Figure 25
Photovoltaic Solar Resource



Source: National Renewable Energy Laboratory, Dynamic Maps, GIS Data, & Analysis Tools, online at: http://www.nrel.gov/gis/solar.html.

Offshore wind is closer to load centers, but is much more expensive. According to EIA's AEO2014, capital costs for offshore wind are nearly three times as high as onshore wind, while fixed operating and maintenance costs are nearly twice as high.[78] Offsetting the higher fixed costs for offshore wind are lower transmission costs, potentially higher capacity factors, and better coincidence with customer demand.[79]

Utility scale solar development would also be spurred by a GHG policy. In AEO2014's most stringent GHG policy case (GHG25), solar generation grows rapidly, and by 2040 is about half of wind generation.

7. Renewable Expansion

Renewable capacity, mostly wind and now solar in some regions, has grown dramatically over the past ten years and is projected to continue to grow—though at a slower pace—through the

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78 See *Assumptions To AEO2014*, Energy Information Administration, June 11, 2014. Available at: http://www.eia.gov/forecasts/aeo/assumptions/

79 Todd, Jennifer and Liz Thorensten, *Creating the Clean Energy Economy Analysis of the Offshore Wind Energy Industry*, International Economic Development Council, 2013.

end of the decade as state RPS mandates are fulfilled.[80] Through 2013, the growth was largely limited to 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 two to three years.

Significant wind additions began in 2006 spurred by then-high natural gas prices (and high wholesale energy prices) and the production tax credit (PTC). We are now on the tail end of the PTC credits for wind. To receive the PTC, units had to be under construction by December 31, 2014 and in-service by the end of 2015.[81]

Wind capacity currently is 62 GW with 13 GW under construction; see Figure 26 for details. There is also potential for another 7 GW or more through 2020 based on the announced projects currently in early stage development.[82] Current solar capacity of 9.5 GW is significantly lower than wind capacity, though it is expected to grow substantially in the next several years, as depicted in Figure 27.

While state Renewable Portfolio Standard (RPS) mandates continue to increase through 2020 (and in some cases beyond), the capacity to meet the goals and targets may be in place by 2016–2017. In the regions with the highest quality wind resources power purchase agreements for wind power have been as low as \$25/MWh after taking the PTC (\$23/MWh) into account.[83] Contracts for solar PV generation have recently been signed at \$50/MWh.[84] Future builds beyond the current RPS mandates will be highly dependent on whether states choose to increase their mandates and on whether the federal government reintroduces the PTC in the coming years and extends the Investment Tax Credit (ITC) beyond 2016.

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80 This situation could change as the relative costs for renewables versus other resources changes as a result of technology costs and changes in state and federal tax policies, as well as state compliance plans filed with EPA when its pending Clean Power Plan rulemaking is finalized.

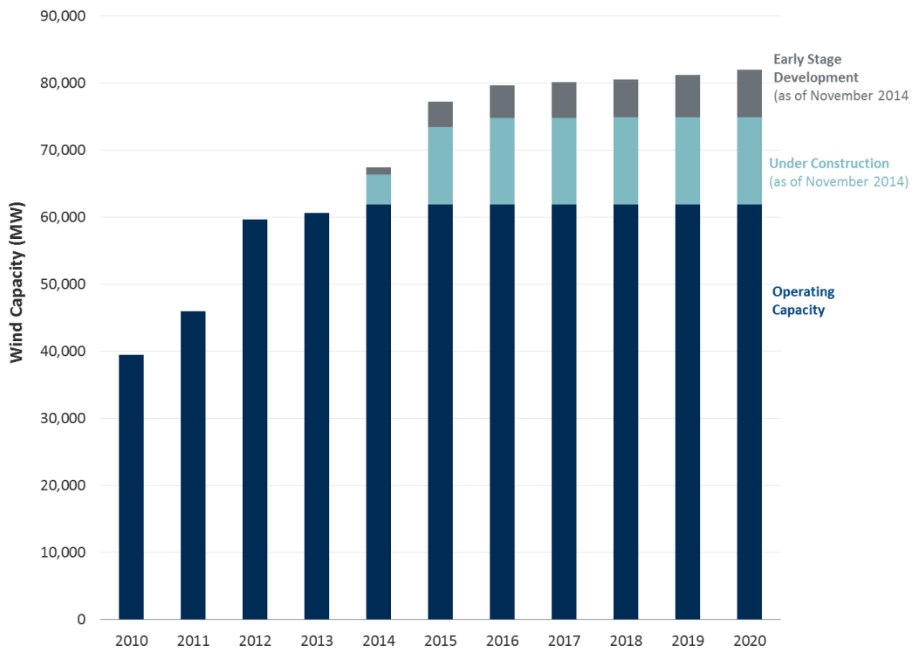
81 The IRS has issued guidance to clarify eligibility for the PTC. See http://www.irs.gov/pub/irs-drop/n-13-60.pdf.

82 ABB Inc., Velocity Suite, accessed on August 26, 2014. Capacity that has applied for or received the necessary permits to be built (but have not yet started construction) were included as early stage development projects. The capacity was conservatively derated by 30% reflecting the fact that not all of the capacity will be built.

83 Wiser, Ryan, Mark Bolinger, *2013 Wind Technologies Market Report*, Lawrence Berkeley National Lab, August, 2014, available at http://emp.lbl.gov/sites/all/files/lbnl-6809e.pdf

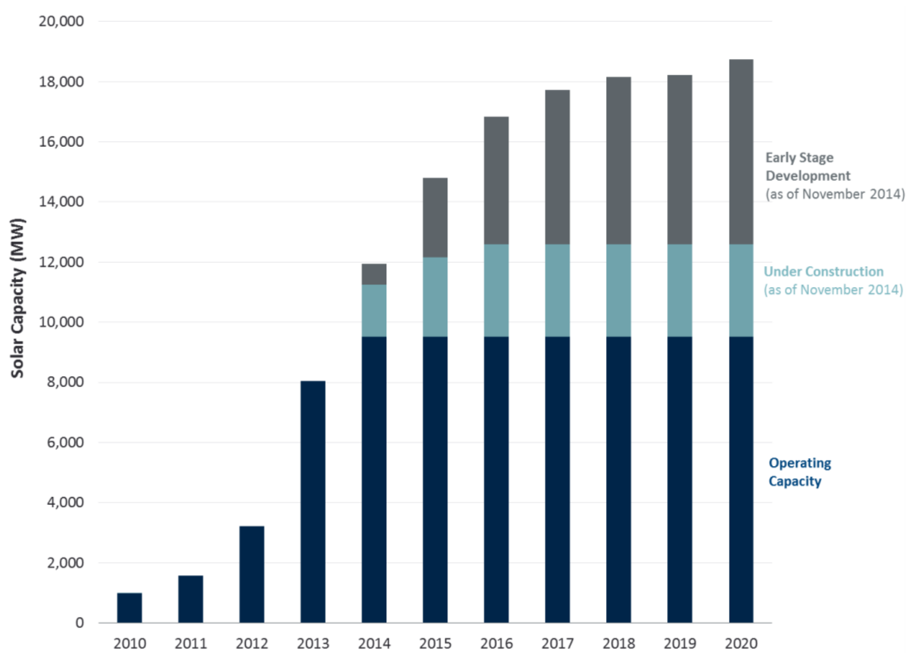
84 Bolinger, Mark, Samantha Weaver, *Utility-Scale Solar 2013: An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States*, Lawrence Berkeley National Lab, September, 2014, available at http://emp.lbl.gov/sites/all/files/LBNL_Utility-Scale_Solar_2013_report.pdf.

Figure 26
Historic and Projected U.S. Wind Capacity through 2020, by Expected Completion Date



Source and Notes: Historical capacity for 2010 to 2012 is from EIA, Existing Nameplate and Net Summer Capacity by Energy Source, Producer Type and State (EIA-860). 2013 and beyond is from ABB, Inc., Velocity Suite, accessed on August 26, 2014. See footnote 83 for explanation of capacity considered to be in early stage development.

Figure 27
Historic and Projected U.S. Solar Capacity through 2020, by Expected Completion Date



Source and Notes: Historical capacity for 2010 to 2012 is from EIA, Existing Nameplate and Net Summer Capacity by Energy Source, Producer Type and State (EIA-860). 2013 and beyond is from ABB, Inc., Velocity Suite, accessed on August 26, 2014. See footnote 83 for explanation of capacity considered to be in early stage development..

G. CHANGING BUSINESS MODELS

The technological, regulatory, and economic changes discussed thus far will all have important direct implications for the development of the nation's electric infrastructure. However, they are also all contributing to the emergence of new business models that both reflect and shape the changing landscape. This section outlines several major developments shaping these new business models, although an exhaustive policy review is beyond the scope of the current report.

Prior to 1978 the majority of electricity infrastructure was owned and operated by vertically-integrated investor-owned utilities that received cost recovery for expenses and earned a regulated rate of return on investment.[85] The first policy that changed this business model was the Public Utility Regulatory Policy Act of 1978 (PURPA) which required that utilities buy power from Independent Power Producers (IPPs) who built "qualifying facilities," which were often natural gas-fired cogeneration units.[86] This spurred the development of efficient NGCC units. In 1992 FERC Order No. 636 deregulated the natural gas industry, while in the same year the Energy Policy Act created a new class of generators that were exempt from the Public Utilities Holding Company Act of 1935.[87,88] This led to a surge in the number of IPPs. In 1996 FERC Order No. 888 opened up the transmission system to IPPs and others making it possible for IPPs to compete with utility-owned capacity.[89]

Between 1996 and 1999 several states including California, Texas, Illinois, Pennsylvania, New York, and Maryland deregulated the generation in their states and allowed customers to purchase power directly from power marketers with their local utility delivering the power.[90] In these states most of the generation owned by the vertically-integrated utilities was sold to independent generation companies, or spun off into independent subsidiaries of the utilities. The result was that many utilities became "wires" companies. All these changes resulted in a patchwork of regulated, partially regulated, and fully deregulated generation across the country.

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85 Besides investor-owned utilities, there existed then and still does a sizeable amount of infrastructure that is owned by publicly-owned and cooperatively-owned electric utilities. Assets are also owned by the Federal government through four power marketing administrations, the Tennessee Valley Authority, and electricity-generating dams of the Bureau of Reclamation and U.S. Corps of Engineers.

86 A qualifying facility under PURPA is either a "small power producer" (80 MW or less) that uses renewable energy, or a cogeneration facility. http://www.ferc.gov/industries/electric/gen-info/qual-fac/what-is.asp.

87 FERC, Order No. 636 - Restructuring of Pipeline Services, Updated June 28, 2010, online at: http://www.ferc.gov/legal/maj-ord-reg/land-docs/restruct.asp.

88 H.R.776.ENR 102nd Cong (1992) Energy Policy Act 1992.

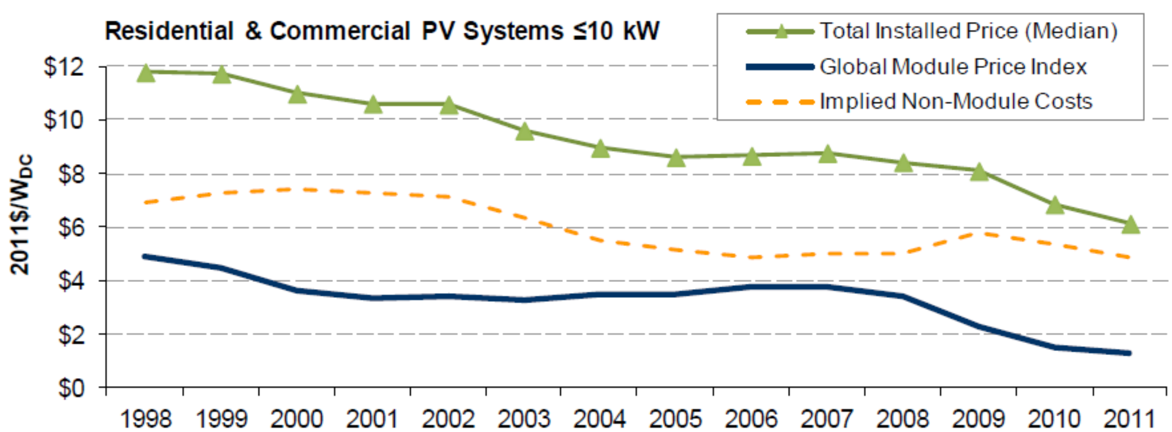
89 FERC, Order No. 888, Updated June 28, 2010, online at: http://www.ferc.gov/legal/maj-ord-reg/land-docs/order888.asp.

90 U.S. Energy Information Administration, Electricity, Restructuring Status, Status of Restructuring by State, online at http://www.eia.gov/electricity/policies/restructuring/restructure_elect.html.

Several more recent policy and technological developments are again creating new opportunities for some market participants while posing challenges to traditional utilities. A primary example is FERC Order No. 1000, issued in 2010, which among other things, made it possible for independent transmission companies and developers to compete with incumbent transmission owners.[91] Up until Order No. 1000, an incumbent transmission owner had a right of first refusal on all transmission projects, which made it very difficult for non-incumbents to compete. Additional impacts of Order No. 1000 on transmission planning are discussed in Section II.D.3.

Changes affecting the development of solar power generation provide another example of technological and regulatory forces that have combined to place significant pressure on the utility business model. The first factor is a dramatic drop in the cost of solar panels, as demonstrated in Figure 28. From 2002 to 2011 the cost of residential and commercial solar photovoltaic dropped by about 40%.

Figure 28
Residential and Commercial Solar Photovoltaic Costs



Source: Barbose, Galen, Naïm Darghouth, and Ryan Wiser, *Tracking the Sun V: An Historical Summary of the Installed Price of Photovoltaics in the United States from 1998 to 2011*, Lawrence Berkeley National Laboratory, November 2012, p. 14. Available at http://emp.lbl.gov/sites/all/files/lbnl-5919e.pdf.

The second factor, present in most states, is net metering. Net metering is a policy that has been instrumental in particular for the development of distributed renewable energy resources such as residential PV and some small-scale wind.[92] Under net metering, a retail customer who generates their own power is effectively paid their current retail electric price for their generation by their local utility.

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[91] FERC, Facts, Order No. 1000 Final Rule on Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, Docket No. RM10-23-000, July 21, 2011. Available at: http://www.ferc.gov/media/news-releases/2011/2011-3/07-21-11-E-6-factsheet.pdf.

[92] See, e.g., Solar Energy Industries Association, "Net Metering." http://www.seia.org/policy/distributed-solar/net-metering; Edison Electric Institute, "Straight Talk About Net Metering." http://www.eei.org/issuesandpolicy/generation/NetMetering/Documents/Straight%20Talk%20About%20Net%20Metering.pdf.

These two factors, along with tax credits, have made distributed PV economic for some ratepayers based on their avoided volumetric retail charges. Some homeowners and businesses own and install their own PV systems. However, most PV systems are installed by outside companies that own the PV systems and enter into a power purchase agreement with the electricity user.

These systems are located behind the meter and reduce sales by utilities. In order for the utility to cover its fixed costs, it must collect more from its remaining load.[93] With a smaller load, this can only be accomplished through higher retail rates. The fact that under net metering programs utilities pay the retail rate for electricity from distributed sources (rather than the lower wholesale rate) may increase rates.

There are three aspects of this problem that will have to be addressed. First, how can rates be designed that are fair to all ratepayers? Second, how can legal and regulatory systems be modified to ensure that service providers (at all levels) are appropriately compensated for providing the necessary infrastructure to ensure power system reliability? Third, how should costs and benefits be measured?

H. Report Structure

The remainder of this report is organized to reflect the focus on transmission, distribution, and storage. Each section contains a more detailed description of the physical system involved in that function, and will contextualize the trends discussed above and the implications for each function. However, it is important to recognize the interdependencies among the different components and functions of the electric system. Accordingly, there will necessarily be some overlap among these three sections. Nonetheless, it is helpful to examine each of the focal functions separately in order to understand the specific roles and challenges faced by each, as well as the implications for infrastructure development at each level.

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93 Fixed costs for utilities are those costs that do not vary with variation in the amount of electricity sold, such as the financing and upkeep of the large capital assets that form most energy infrastructure in this country. Variable costs depend on the level of generation and include fuel costs and some labor costs involved in operations and maintenance.

II. Transmission

A. Physical Summary of the Transmission System

In this section, we provide an overview of the transmission system, including its current role, characteristics of the system, and historic and projected levels of transmission investment. Physical vulnerabilities are discussed separately in the subsequent section.

1. Role of the Transmission System

The role of the high-voltage electric transmission system is to transport electric power generated from a wide range of generation facilities to the low-voltage distribution systems serving the end-use consumers. Historically, most power generation facilities have been located at a distance from the electricity demand they serve due to economies of scale of building larger, centralized generation facilities, access to low cost fuel (*e.g.*, mine-mouth coal-fired generation plants), access to geographically-constrained resources (*e.g.*, hydroelectric generation stations and wind farms), and environmental and zoning regulations that make building generation facilities near or within cities difficult or more costly. The transmission network was built to connect these generation resources to the load while maintaining a high level of reliability of electric power delivery to consumers. Reliability is enhanced by the network of transmission lines that provide redundancy, alternative paths for power to serve consumers' energy demand over a large geographical area, and facilitates trade between regional entities (*e.g.*, utilities and RTOs) and competition across different resources to meet consumers' need.

The regulatory requirements for transmission planning and development have shifted over time. In 1996, FERC Order No. 888 required that generators be given non-discriminatory open access to the transmission system and more recently FERC Order No. 1000 requires transmission planning to occur on the regional and interregional level for identifying transmission projects that span large geographical areas and affect diverse electricity customers.[94] These policies will continue to affect the pace, size, and efficiency of transmission system expansions and thus are important drivers for the future of the power industry.

In this section, we provide an overview of the physical characteristics of the transmission network and an outlook of the transmission investment projected through 2020. Later sections provide further details on the physical vulnerabilities of the transmission network, trends of the main drivers for building new transmission, the evolving transmission planning processes, and finally international transmission issues related to increasing interconnections with Canada and Mexico.

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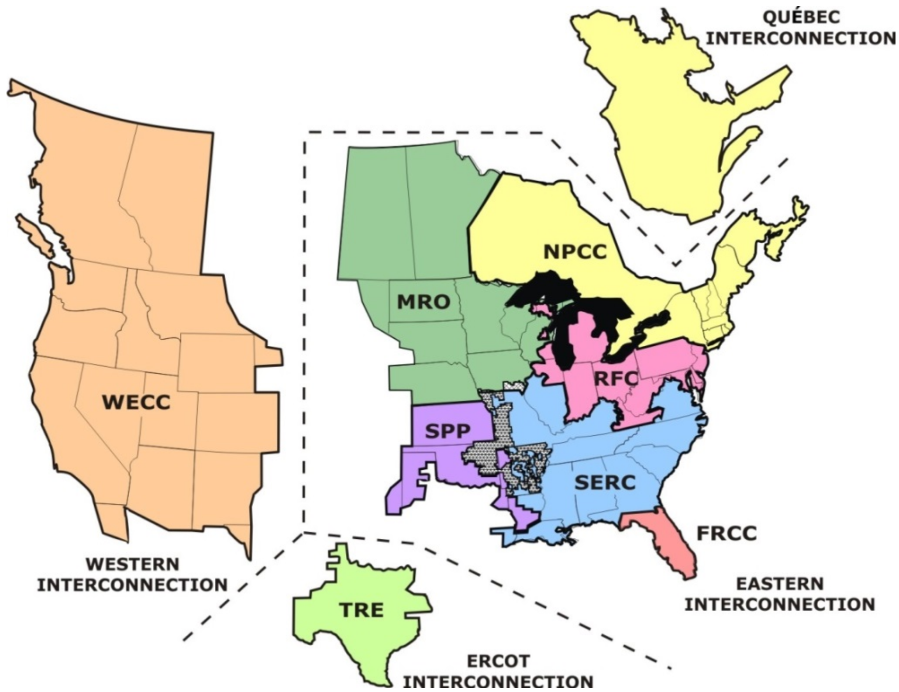
94 See further information on the FERC orders at: http://www.ferc.gov/legal/maj-ord-reg.asp.

2. Physical Characteristics of the Transmission Network

The electric transmission system in the U.S. is part of a larger network that spans North America across four relatively independent, synchronous networks called "interconnections," as shown in Figure 29.[95] Within the interconnections, eight regional entities are delegated by NERC to monitor and enforce compliance with NERC's reliability standards and criteria.[96]

Figure 29
North America Electric Reliability Corporation Interconnections and Regional Entities



Source: NERC, Key Players, accessed September 25, 2014, online at http://www.nerc.com/AboutNERC/keyplayers/Pages/default.aspx

An example of the existing transmission network at the regional level is shown for the PJM Interconnection in Figure 30, which covers all or parts of twelve states in the Mid-Atlantic and Midwest. The map highlights the network of lines and substations operating at voltages of 345–765 kilovolts (transmission at lower voltages not shown) that make up the transmission network.

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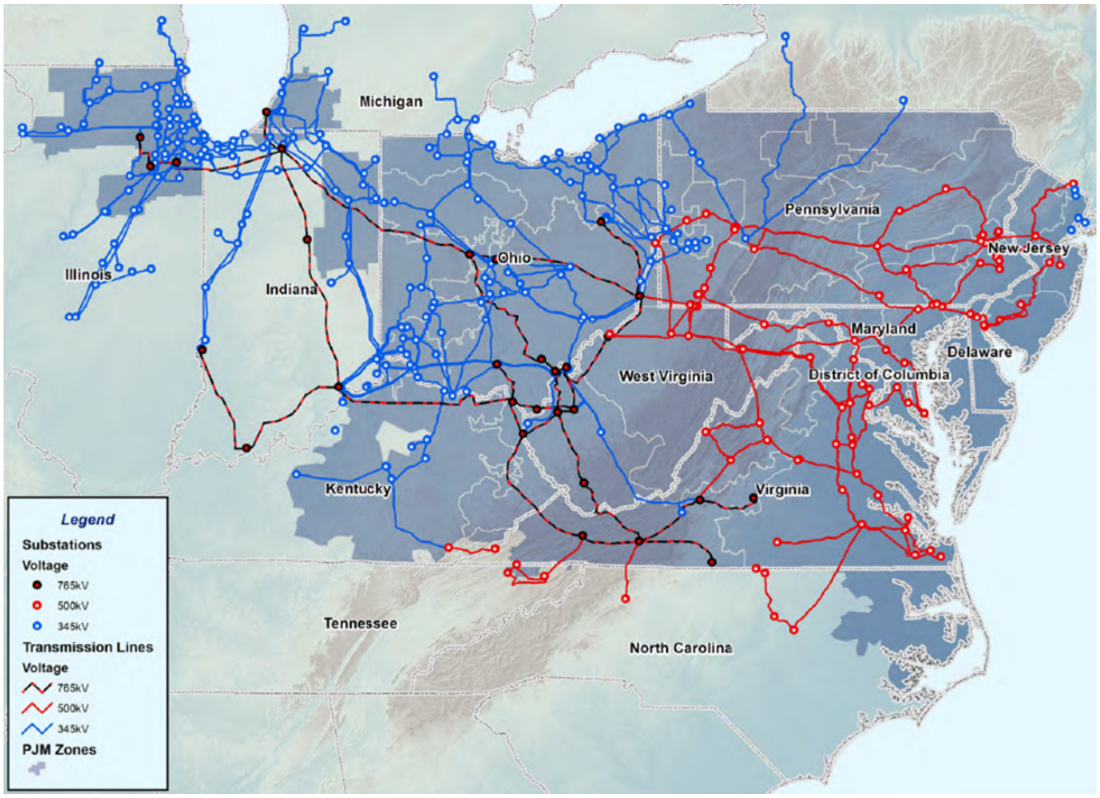
95 A synchronous network maintains the same frequency across the entire system. In contrast, systems are considered asynchronous when the frequencies at which they operate are not timed to each other, or in other words are not in sync.

96 NERC, Key Players, accessed September 25, 2014, online at: http://www.nerc.com/AboutNERC/keyplayers/Pages/default.aspx

Figure 30
PJM Transmission Network



Source: PJM, 2013 PJM Regional Transmission Expansion Plan (RTEP), Book 1: RTEP in Review, February 28, 2014.

The transmission network is designed as the physical "backbone" of the electric system to maintain reliable operation of the power system as well as enhance economic efficiency and enable public policy objectives, as discussed further in later sections. The North American Electric Reliability Council (NERC) and its regional entities set reliability standards that transmission engineers at RTOs and local utilities apply when studying the future of their systems, and that system operators track in real time while deciding which generation facilities to dispatch. Operating the transmission network is a dynamic and complex challenge as actual demand will differ from forecasted demand, and generation and transmission facilities will experience unexpected outages.

In its 2013 Long-Term Reliability Assessment, NERC reviewed key reliability indicators that may impact the power system in North America over the next ten years.[97] Transmission-specific long-term issues identified by NERC for maintaining reliability include the operation and planning challenges of integrating renewables, coal and nuclear retirements, increased dependency on natural gas-fired generation, and uncertainty created by the adoption of demand side management technologies.

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[97] NERC, 2013 Long-Term Reliability Assessment, December 2013. Available at http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2013_LTRA_FINAL.pdf.

Additional vulnerabilities (including physical, cyber, and natural) beyond those considered by traditional reliability planning criteria are discussed in more detail in the next section.

Transmission constraints occur when the power flow across a transmission line or a group of lines reaches the physical capacity of the line or would do so in the case of a contingency event, known as a contingency constraint.[98] The constraints create congestion on the system that can limit the ability of the transmission network to serve new load and can lead to higher local energy prices, which can often be quite dramatic. The DOE released its draft National Electric Transmission Congestion Study in August 2014 that provides a summary of the indicators of where congestion is most prominent across four regions of the U.S.[99] The regional findings of the DOE draft study are summarized in Table 4.

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98 Contingency constraints occur when the system operator determines that if another transmission element (usually a transmission line, transformer, or large generator) were to fail, the power flow across the transmission line would exceed its physical capacity.

99 DOE, Office of Electricity Delivery and Energy Reliability, *National Electric Transmission Congestion Study, Draft for Public Comment*, August 2014. Available at: http://www.energy.gov/oe/downloads/national-electric-transmission-congestion-study-draft-public-comment-august-2014. Note that the 2015 study "does not apply congestion labels to broad geographic areas, such as the 'critical congestion areas,' 'congestion areas of concern,' and 'conditional congestion areas' identified in earlier studies."

Table 4
Summary of National Electric Congestion Study Findings

Region	Findings
Western Interconnection	- Many paths heavily utilized but do not appear to act as reliability-threatening constraints - More congestion expected due to new development of renewable resources and generator retirements - San Onofre Nuclear Generating Station closure created local reliability challenges
Midwest (Midcontinent ISO North, Southwest Power Pool, western PJM, non-RTO areas)	- Congestion results from transmitting high and growing levels of wind generation from western sources to distant loads - Differences in generation capacity reserve margins, which are higher in the west and central regions, increase west-to-east flows which creates congestion
Northeast (NYISO, ISO-NE, eastern PJM)	- Constraints have impacted flows for fewer hours in recent years - Congestion lower due to generation and transmission additions combined with lower demand - Congestion persists in central New York, New York City, and Long Island areas - Increasing congestion due to west-to-east flows of off-peak generation from remote wind locations
Southeast (Non-RTO areas in NC, SC, TN, AR, GA, AL, MS, LA, FL, parts of TX)	- No reports of persistent transmission constraints

Source: DOE, Office of Electricity Delivery and Energy Reliability, National Electric Transmission Congestion Study, Draft for Public Comment, August 2014.

Transmission congestion however does not directly indicate a lack of reliability. As noted by the DOE study:

> [The] presence of transmission congestion reflects only a desire or demand for increased transmission system utilization. Whether it is appropriate to mitigate transmission congestion requires information and judgment about the purposes or objectives that would be served.[100]

Transmission of electricity over long distances results in energy losses due to the physical resistance of transmission lines and other equipment, such as transformers. As explained in the Distribution section, there is limited data on transmission-specific losses, however the EIA estimates transmission and distribution system energy losses were approximately 5% in 2012.[101]

3. Historical Build versus Future Projections

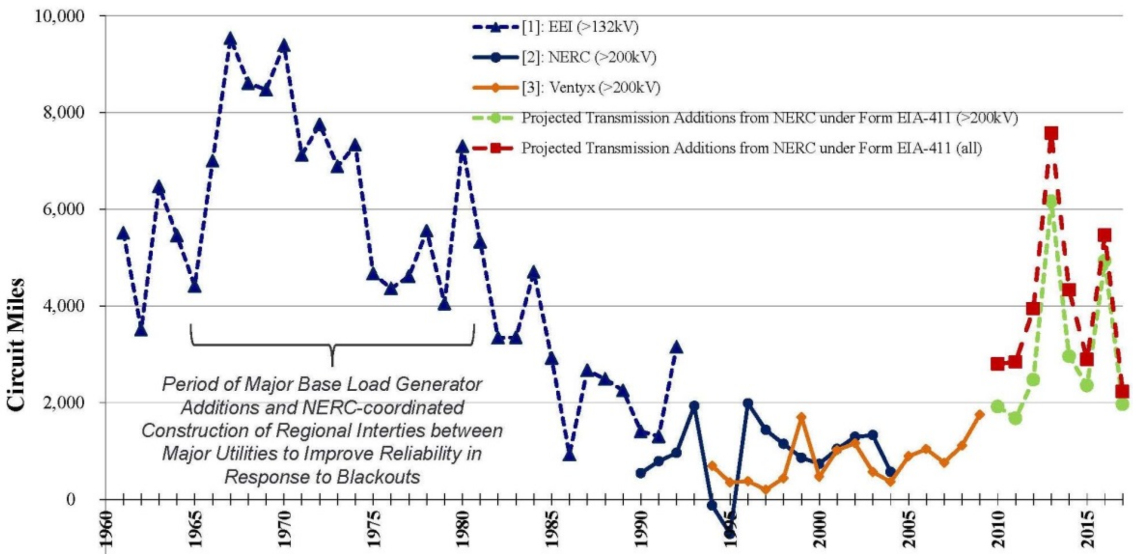
Looking forward over the next several years, transmission investment is projected to be higher than the past decade for replacing aging infrastructure, maintaining system reliability, facilitating

100 *Id.*, p. xii.

101 U.S. Energy Information Association, Form EIA-923 detailed data with previous form data (EIA-906/920), Annual final 2013 data Release: January 19, 2015, online at http://www.eia.gov/electricity/data/eia923/.

competitive wholesale power markets, and aiding regions in meeting public policy objectives. Analysis of historical transmission development activity shows that 1960 to 1980 represented a sustained period of development of the transmission network, followed by a period of relatively limited activity during the 80s and 90s, as shown in Figure 31 based on circuit miles added to the system. Since 2000, transmission investments have been rising due to a variety of factors which are discussed in more detail in later sections.

Figure 31
Historic and Projected Expansion of Transmission Circuit Miles



Sources and notes: Judy Chang, Johannes Pfeifenberger, and Michael Hagerty, Trends and Benefits of Transmission Investments: Identifying and Analyzing Value, presented to CEA Transmission Council, Ottawa, Canada, September 26, 2013. Available at http://www.brattle.com/system/publications/pdfs/000/004/944/original/Trends_and_Benefits_of_Transmission_Investments_Chang_Pfeifenberger_Hagerty_CEA_Sep_26_2013.pdf

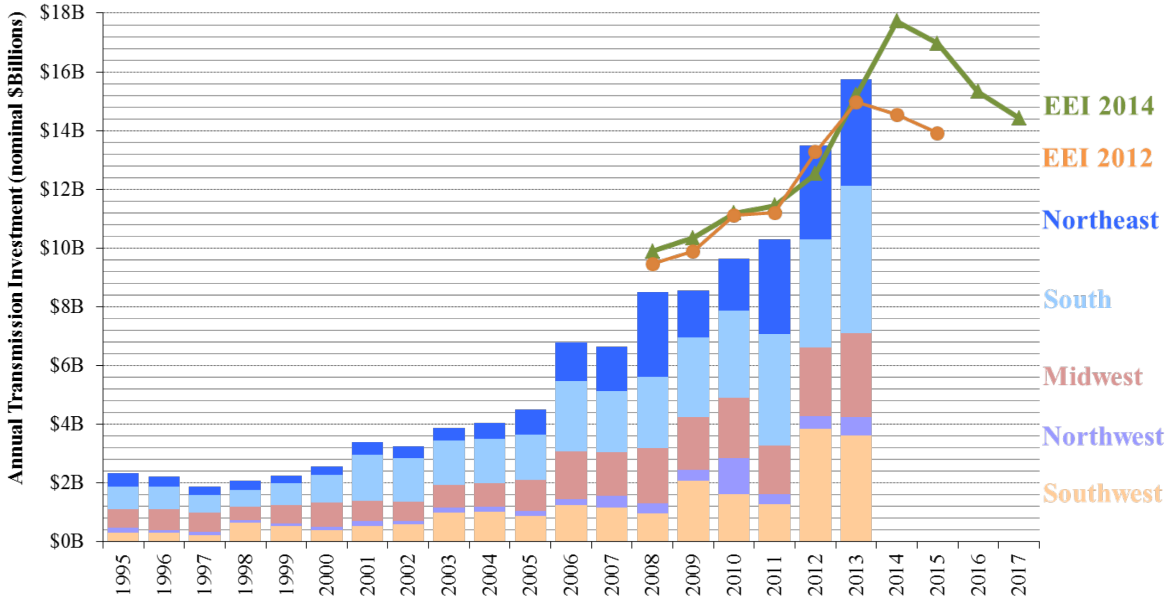
The annual transmission investments of FERC-jurisdictional utilities and independent transmission developers has grown from approximately $2 billion in 2000 to over $16 billion in 2013, as shown in Figure 32.[102] EEI projects annual transmission investment through 2017 to remain above $14 billion per year.[103]

102 FERC-jurisdictional transmission represents approximately 80% of all transmission in the Eastern Interconnection and about 60% in the Western Interconnection. BPA and WAPA as federal Power Marketing Administrations are non-FERC jurisdictional. Neither is ERCOT as it is located solely in a single state (*i.e.*, Texas).

103 Edison Electric Institute, "Actual and Planned Transmission Investment By Investor-Owned Utilities (2007–2016)," Updated May 2014. Available at:

http://www.eei.org/issuesandpolicy/transmission/Documents/bar_Transmission_Investment.pdf
Projected investment is shifted forward by a year to align EEI projections with costs expected to be reported in FERC Form 1 data. Values have been converted from real 2012 dollars to nominal dollars.

Figure 32
Annual Transmission Investment by FERC Subregion compared to EEI Projections



Sources and notes: Pfeifenberger, Johannes, Judy Chang, John Tsoukalis, Dynamics and Opportunities in Transmission Development, Presented to TransForum East, December 2, 2014. Available at: http://www.brattle.com/system/publications/pdfs/000/005/089/original/Dynamics_and_Opportunities_in_Transmission_Development.pdf. The Brattle analysis of FERC Form 1 data compiled in ABB Inc.'s Velocity Suite. Based on EIA data available through 2003, FERC-jurisdictional transmission owners estimated to account for 80% of transmission assets in the Eastern Interconnection, and 60% in WECC and ERCOT. Facilities >300kV estimated to account for 60–80% of shown investments. EEI annual transmission expenditures updated May 2014 shown (2008–2017) based on prior year's actual investment through 2012 and planned investment thereafter. Annual investment values are in nominal dollars.

Regionally, transmission investment differs significantly. As shown in Table 5, California and New England systems have had the most significant investment per megawatt of demand between 2008 and 2012, which is three to four times higher than in several regions around the country.[104]

[104] Analysis is based on estimated total industry annual investment divided by peak demand in each year. Data for all regions except Entergy is based on annual investment by FERC Form 1 filers (estimated to represent 70% of total industry investment) grossed up to 100% of the industry to reflect investment from cooperatives, municipals, and state and federal power. Entergy reflects only FERC Form 1 investment. SPP peak demand is based on reliability footprint. Annual investment values are in nominal dollars.

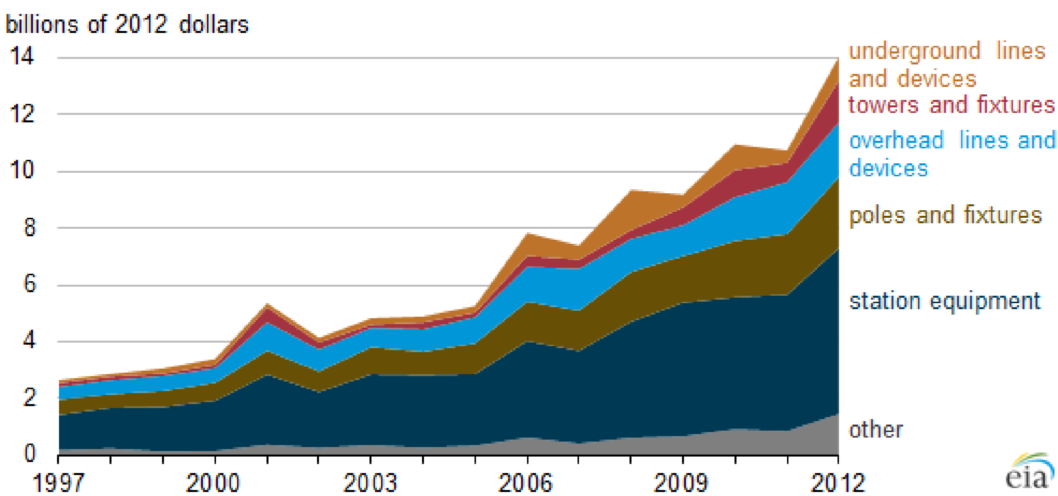
Table 5
Analysis of Transmission Investment per MW of Peak Demand

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**
Entergy	$12,617	$6,598	$19,730	$18,728	$17,977	**$15,100**
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**

Sources and Notes: Analysis by The Brattle Group is based on estimated total industry annual investment divided by peak demand in each year. Data for all regions except Entergy is based on annual investment by FERC Form 1 filers (estimated to represent 70% of total industry investment) grossed up to 100% of the industry to reflect investment from cooperatives, municipals, and state and federal power. Entergy reflects only FERC Form 1 investment. SPP peak demand is based on reliability footprint. Annual investment values are in nominal dollars.

EIA analysis shows the trend in transmission investment over the past 15 years by equipment type with almost half of the costs attributable to station equipment, as shown in Figure 33.[105]

Figure 33
1997–2012 Annual Investment in Transmission Infrastructure by Investor-Owned Utilities



Source: EIA, Today in Energy, Investment in electricity transmission infrastructure shows steady increase, August 26, 2014, online at http://www.eia.gov/todayinenergy/detail.cfm?id=17711

Looking forward, there are currently over $100 billion approved and proposed transmission projects, which may be developed as these projects advance through the permitting, siting, and

[105] U.S. Energy Information Administration, Today in Energy: Investment in electricity transmission infrastructure shows steady increase, August 26, 2014, online at http://www.eia.gov/todayinenergy/detail.cfm?id=17711

construction processes.[106] The estimated annual transmission investments are expected to be in the range of $120–160 billion per decade.[107] In addition to building lines for maintaining reliability, significant investment will be related to integrating growing levels of renewable energy generation and replacing or upgrading aging facilities.

As transmission investments increase over time, developers will face increasing pressure to keep the costs of transmission low while providing significant value to the system as a whole and all transmission customers. Estimating the rate impact is difficult due to such regional differences. However, assuming that the industry invests $12–16 billion per year from 2015 to 2020, the transmission component of average retail rates would likely increase by 0.2 to 0.3 cents per kilowatt-hour by 2020 on average across U.S. ratepayers.[108] The realized retail cost impacts however may or may not increase for all ratepayers depending on where the investment occurs and whether the transmission facilities impact the total delivered cost of power, increase competition in the wholesale markets, and/or allow lower cost electricity to reach customers.

B. TRANSMISSION SYSTEM VULNERABILITIES

The security of the transmission system has recently been an area of focus as threats have increased, as well as the awareness of potential consequences. The electric transmission network stretches over large geographic areas and generally is not well guarded against either physical or cyber damage, which makes the transmission network inherently vulnerable to malicious physical attacks, cyber-attacks, and weather related damage.[109]

As the majority of the U.S. power grid is regulated at the state level and is privately owned, federal initiatives to decrease physical vulnerabilities are challenging.[110] Emerging trends, such as the increasing severity of storms due to climate change, are compounding the vulnerabilities already facing the grid and will require new tools and solutions.

1. Cyber Security Threats to Transmission and Distribution

In the electric power sector, "cybersecurity" threats refer to deliberate, internet-based attacks on critical facilities or other components of the electric system from organized crime engaging in

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106 Brattle analysis of publicly available transmission plans from RTOs and other entities, accounting for potential overlap between projects where possible.

107 Pfeifenberger, Johannes, Judy Chang, John Tsoukalis, Dynamics and Opportunities in Transmission Development, Presented to TransForum East, December 2, 2014. Available at: http://www.brattle.com/system/publications/pdfs/000/005/089/original/Dynamics_and_Opportunities_in_Transmission_Development.pdf

108 The 2020 rate impact is calculated assuming $15 billion of investment per year for six years (2015 – 2020) is amortized over 40 years based on a 9.0% cost of capital and averaged over U.S. annual energy demand of approximately 4 trillion kWh.

109 National Research Council, *Terrorism and the Electric Power Delivery System* (Washington, DC: The National Academies Press, 2012).

110 See Figure 11.

extortion or from terrorists or foreign governments engaging in warfare. Actors based in foreign countries are known to have conducted cyber probes of U.S. grid systems to test for potential vulnerabilities.[111] Potential cyber-attacks on transmission and distribution infrastructure could include the manipulation or disabling of the supervisory control and data acquisition systems used to communicate between substations and equipment, hacking into utility information technology systems or Energy Management Systems, or disruption of substation automation equipment. In 2012, DHS identified a 68% increase in cyber-incidents for federal and critical infrastructure[112] and found that reports of cyber-attacks on utility sector control systems had increased more than 50%.[113]

While cyber-attacks are trending upward, the full extent and nature of the vulnerabilities remains unclear. Not only is the complexity of grid operations growing at an unprecedented rate, utilities often are reluctant to report attacks. In a recent anonymous survey utilities described "malicious" attacks "seeking to gain access to internal systems" that were "daily" and "constant."[114]

The growing use of new, complex, and data-intensive technologies across the sector, such as smart meters, electric vehicles (EVs), distributed generation, and microgrids may create new vulnerabilities and opportunities for cyber-attacks if these systems are not adequately protected. Utility Control Systems (also known as Operational Technologies—OT) were traditionally isolated from other systems but are now merging with information technology (IT) systems in order to integrate these new technologies. New systems with added devices, communication networks, and software are more complex and require new cyber security technologies to match their new structures. In addition, ICS require higher levels of reliability than IT systems traditionally have, making newly merged systems a reliability concern for utilities.[115]

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111 Markey, Edward J. and Henry A. Waxman, U.S. House of Representatives, *Electric Grid Vulnerability: Industry Responses Reveal Security Gaps*, May 21, 2013. Available at: http://democrats.energycommerce.house.gov/sites/default/files/documents/Report-Electric-Grid-Vulnerability-2013-5-21.pdf.

112 *Id.*

113 Tryon, Ahren and Cozen O'Connor, "Industrywide cybersecurity standards emerging through voluntary framework," *Electric Light and Power*, June 12, 2012, online at http://www.elp.com/articles/print/volume-91/issue-3/sections/industrywide-cybersecurity-standards-emerging-through-voluntary-framework.html.

114 Markey, Edward J. and Henry A. Waxman, U.S. House of Representatives, *Electric Grid Vulnerability: Industry Responses Reveal Security Gaps*, May 21, 2013. Available at: http://democrats.energycommerce.house.gov/sites/default/files/documents/Report-Electric-Grid-Vulnerability-2013-5-21.pdf.

115 Malashenko, Elizaveta, Chris Villarreal, and J. David Erickson, *Cybersecurity and the Evolving Role of State Regulation: How it Impacts the California Public Utilities Commission*, California Public Utility Commission Grid Planning and Reliability Paper, September 19, 2012, available at http://www.cpuc.ca.gov/NR/rdonlyres/D77BA276-E88A-4C82-AFD2-FC3D3C76A9FC/0/TheEvolvingRoleofStateRegulationinCybersecurity9252012FINAL.pdf.

Continued on next page

Cyber security is not a new issue for the utility industry. The vulnerabilities were highlighted however in 2006 when the "Aurora" project by the Department of Homeland Security (DHS) Control Systems Security Program demonstrated an attacker could cause severe damage by hacking into the control system of an electric generator or other rotating equipment connected to the grid and throw the equipment out of phase.[116]

Recognizing these threats, utilities are deploying cybersecurity plans to protect their entire infrastructure: generation, transmission, and distribution systems. FERC,[117] NERC,[118] DHS,[119] the National Institute of Standards and Technology (NIST)[120] and DOE[121] are leading development of guidance and models for implementing security. NERC has taken the lead in establishing both mandatory and voluntary security standards for utilities called Critical Infrastructure Protection Standards (CIP). The NERC-CIP, however, primarily covers generation and bulk transmission assets that qualify as "critical assets" or "critical cyber-assets" and excludes 80 to 90 percent of the grid, mainly distribution infrastructure. Regulation of distribution assets falls under the authority of state public utility commissions who may need to become more involved in cybersecurity.[122] Federal cyber security initiatives for distribution are mostly voluntary and focus on Smart Grid integration. The DOE has coordinated with utilities to form the Advanced Metering Infrastructure Security (AMI-SEC) Task Force to develop standards for AMI assets, NIST has developed a Smart Grid Framework with voluntary standards that the FERC could make enforceable, and DHS has identified recommended practices in resources such as its "Catalog of Control Systems Security: Recommendations for Standards Developers."[123] DHS has also teamed with the DOE to develop the Electricity Subsector Cybersecurity Capability

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Continued from previous page

See also Michael Swearingen, Steven Brunasso, Joe Weiss, and Dennis Huber, *What You Need to Know (and Don't) About the AURORA Vulnerability,* POWER Magazine, September 1, 2013,

116 Markey, Edward J. and Henry A. Waxman, U.S. House of Representatives, *Electric Grid Vulnerability: Industry Responses Reveal Security Gaps*, May 21, 2013. Available at: http://democrats.energycommerce.house.gov/sites/default/files/documents/Report-Electric-Grid-Vulnerability-2013-5-21.pdf.

117 See recent highlights of FERC's cybersecurity activities here: http://www.ferc.gov/industries/electric/indus-act/reliability/cybersecurity.asp

118 See NERC's standards for cybersecurity here: http://www.nerc.com/pa/Stand/Pages/CIPStandards.aspx

119 See a review of DHS Cybersecurity activities here: https://www.dhs.gov/topic/cybersecurity

120 See NIST's cybersecurity framework here: http://www.nist.gov/cyberframework/

121 See DOE's cybersecurity activities here: http://energy.gov/oe/services/cybersecurity

122 California Public Utilities Commission, "Cybersecurity and the Evolving Role of State Regulation: How it Impacts the California Public Utilities Commission," September 19, 2012 available at http://www.cpuc.ca.gov/NR/rdonlyres/D77BA276-E88A-4C82-AFD2-FC3D3C76A9FC/0/TheEvolvingRoleofStateRegulationinCybersecurity9252012FINAL.pdf

123. Department of Homeland Security Control Systems Security Program, "Catalog of Control Systems Security: Recommendations for Standards Developers," April 2011. Available at https://ics-cert.us-cert.gov/sites/default/files/documents/CatalogofRecommendationsVer7.pdf.

Maturity Model (ES-C2M2).[124] Some stakeholders note that the current level of cybersecurity is still focused on compliance with standards and needs to be expanded to broader risk management with greater coordination among various planning groups.[125]

2. Physical Attacks on Transmission

On the transmission system, critical facilities targeted for physical attacks include extra high voltage transformers. Transformers located at power plants step power up to higher voltages to travel more efficiently, while transformers at substations step power back down before it enters the distribution grid. As transformers are assets with long lead times to replace, the losses associated with damaged transformers are far reaching, making them a major vulnerability.[126] There has been some success in increasing the country's inventory of spares, but not nearly enough to adequately ensure large scale resiliency against attacks.[127]

DHS has identified damage to transformers as the most likely event if a terrorist were to complete a physical attack on the power system.[128] Interest in preventing physical attacks on transformers escalated in April 2013 when a PG&E substation near San Jose was attacked by "military style" snipers. Suspects fired at transformers, aiming to disable them without creating an explosion.[129] In the fall of 2013 three attacks on energy infrastructure in Arkansas were thought to be related and targeted both transmission poles and a substation.[130] A more recent, but less sophisticated, attack includes a failed bombing attempt at a Nogales, AZ substation.[131]

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124 Edison Electric Institute, "Electric Power Industry Initiatives to Protect the Nation's Grid From Cyber Threats," January 2013, available online at http://www.eei.org/issuesandpolicy/cybersecurity/Documents/Cybersecurity%20Industry%20Initiatives.pdf.

125 Wilshusen, Gregory C., "Cybersecurity: Challenges in Securing the Electricity Grid," Testimony Before the Committee on Energy and Natural Resources, U.S. Senate, July 17, 2012.

126 Wilmshurst, Neil, Luke van der Zel, and Bhavin Desai, "High-Voltage Transformers: Increasing Reliability, Extending Life," *EPRI Journal,* Fall 2009, available at http://mydocs.epri.com/docs/CorporateDocuments/EPRI_Journal/2009-Fall/1020476_Transformers.pdf.

127 National Research Council, *Terrorism and the Electric Power Delivery System* (Washington, DC: The National Academies Press, 2012).

128 *Id.*

129 Smith, Rebecca, "Assault on California Power Station Raises Alarm on Potential for Terrorism: April Sniper Attack Knocked Out Substation, Raises Concern for Country's Power Grid," *The Wall Street Journal*, February 5, 2014, online at http://online.wsj.com/news/articles/SB10001424052702304851104579359141941621778.

130 Blinder, Alan, "Power Grid Is Attacked in Arkansas," *The New York Times*, October 8, 2013, online at http://www.nytimes.com/2013/10/09/us/power-grid-is-attacked-in-arkansas.html?_r=0.

131 Holstege, Sean and Ryan Randazzo, "Sabotage at Nogales Station Puts Focus on Threats To Grid," *The Republic/azcental.com,* June 13, 2014, video and article online at

Continued on next page

Several initiatives were underway at the time of these attacks that may greatly increase transmission security. Examples include efforts to increase transformer security, such as the proposed Grid Reliability and Infrastructure Defense Act (H.R. 4298 and S. 2158)[132] and the second iteration of NERC's grid security exercise called GridEx II.[133] In May 2014, NERC submitted its draft physical security standard for the U.S. high-voltage grid to FERC for its consideration.[134] FERC approved a physical security reliability standard based on the NERC submittal in November 2014.[135]

Physical attacks may also target transmission switches, towers and lines, and control centers although the outages caused are generally not as severe as those caused by critical transformers.[136] Globally, transmission lines and towers are a top target with at least 2,500 attacks during the past decade; substations were the target of close to 500 attacks during the same time.[137] Options for decreasing vulnerability of these assets include the hardening of key substations and control centers, increasing physical surveillance, and adding transmission towers that can prevent domino-like collapse.[138] FERC and various electric industry groups have also issued recommendations to enhance physical security at critical facilities.

Physical attacks also include attacks utilizing electromagnetic pulses, or EMPs. EMPs are short bursts of electromagnetic energy, sometimes called a "transient electromagnetic disturbance." EMP weapons can come in the form of portable equipment that produces high-power radio frequency, microwave, or other electromagnetic pulses that destroy or disable electronic

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Continued from previous page

http://www.azcentral.com/story/news/arizona/2014/06/12/sabotage-nogales-station-puts-focus-threats-grid/10408053/.

132 Parfomak, Paul W., *Physical Security of the U.S. Power Grid: High-Voltage Transformer Substations*, Congressional Research Service Report for Congress 7-5700, R43604, June 17, 2014, available at http://fas.org/sgp/crs/homesec/R43604.pdf.

133 NERC, *Grid Security Exercise (GridEx II): After-Action Report*, March 2014, available at http://www.nerc.com/pa/CI/CIPOutreach/GridEX/GridEx%20II%20After%20Action%20Report.pdf.

134 *Petition of the North American Electric Reliability Corporation For Approval Of Proposed Reliability Standard Cip-014-1*, before the Federal Energy Regulatory Commission, May 23, 2014. Available at: http://www.nerc.com/FilingsOrders/us/NERC%20Filings%20to%20FERC%20DL/Petition%20-%20Physical%20Security%20CIP-014-1.pdf

135 FERC, FERC Approves Physical Security Grid Reliability Standards, November 20, 2014. Available at: http://www.ferc.gov/media/news-releases/2014/2014-4/11-20-14-E-4.asp.

136 Abel, Amy, Paul W. Parfomak, and Dana A. Shea, *Electric Utility Infrastructure Vulnerabilities: Transformers, Towers, and Terrorism*, Congressional Research Service Report for Congress 7-5700, R42795, April 9, 2004, available at http://fas.org/sgp/crs/homesec/R42795.pdf..

137 National Research Council, *Terrorism and the Electric Power Delivery System* (Washington, DC: The National Academies Press, 2012).

138 *Id.*

equipment.[139] The grid is also potentially vulnerable to geomagnetic disturbances that stem from natural causes, such as geomagnetic storms. Geomagnetic storms have caused disruptions on the Hydro-Québec grid in 1989 and in the U.S. Northeast and Mid-Atlantic in 2013. NERC and ISOs monitor solar flares that cause geomagnetic storms such as these hoping to avoid major disruptions if several flares occur at once, making it difficult for the grid to stay stable.[140]

3. Extreme Storms and Climate Change

Weather-related threats to the grid include hurricanes and ice storms, earthquakes, and other natural events that may bring down transmission lines or, less frequently, damage equipment such as substations, transformers, circuit breakers, or terminal facilities for direct-current (DC) lines. While all transmission lines and substations are vulnerable to damage from severe storms, aging infrastructure is more susceptible to the hurricane-related hazards of storm surge, flooding, and extreme winds.

Severe weather is the leading cause of power outages in the United States and costs the U.S. between $25 and $70 billion annually.[141] Avoiding weather related outages is becoming a far more important priority as the severity of destructive storms increases due to climate change. Climate change is estimated to increase the frequency of what were once "100 year storms," leading to devastating storm surges every three to five years.[142] In 2013 there were 9 disasters that each inflicted more than $1 billion in damage and in 2012 there were 11 disasters of such scale, including Hurricane Sandy, which cost at least $50 billion in damage.[143] Many of the outages during Sandy were caused from flooded substations.[144]

In addition to damage from severe storms, transmission infrastructure is vulnerable to other elements of climate change. Other, indirect vulnerabilities include increased risk of wildfires from rising temperatures and drought, which would damage transmission lines. A recent White

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139 Markey, Edward J. and Henry A. Waxman, U.S. House of Representatives, *Electric Grid Vulnerability: Industry Responses Reveal Security Gaps*, May 21, 2013. Available at: http://democrats.energycommerce.house.gov/sites/default/files/documents/Report-Electric-Grid-Vulnerability-2013-5-21.pdf.

140 Esther Whieldon, *RTOs, NERC on the Lookout For Solar Flare Grid Impacts*, SNL News, September 12, 2014.

141 Campbell, Richard J., *Weather-Related Power Outages and Electric System Resiliency*, Congressional Research Service Report for Congress 7-5700, R42696, August 28, 2012. Available at http://fas.org/sgp/crs/misc/R42696.pdf.

142 Lin, Ning, Kerry Emanuel, Michael Oppenheimer, and Erik Vanmarcke, *et al.*, "Physically based assessment of hurricane surge threat under climate change," *Nature Climate Change* 2, February 14, 2012, 462–467, online at http://www.nature.com/nclimate/journal/v2/n6/full/nclimate1389.html.

143 National Climatic Data Center, Billion-Dollar Weather/Climate Disasters: Overview, online at http://www.ncdc.noaa.gov/billions/.

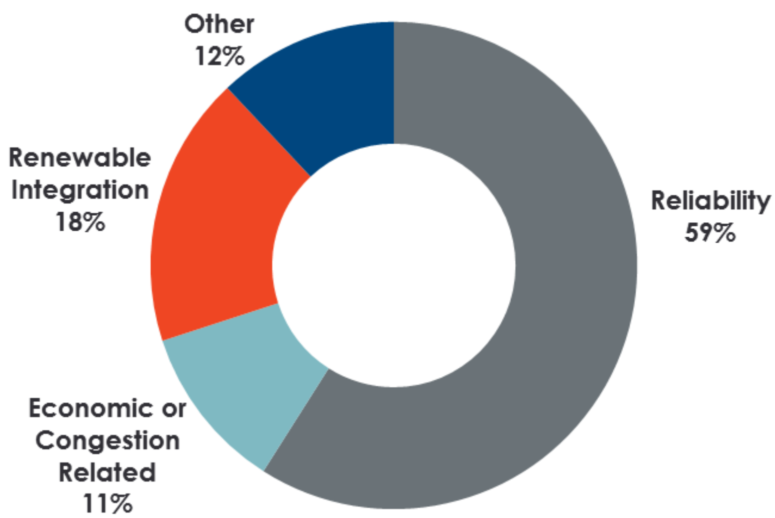
144 plaNYC, The City of New York Mayor's Office, *A Stronger, More Resilient New York*, June 11, 2013, download available at http://www.nyc.gov/html/sirr/html/report/report.shtml.

House report highlights the importance of investing in modern infrastructure to maintain grid reliability and cites research by the U.S. Global Change Research Program (USGCRP) that climate change will result in higher national and global temperatures, warmer oceans, rising sea levels, and increased heavy precipitation events.[145]

C. Drivers of New Transmission Investment

As discussed previously, transmission investment is currently at a historically high level with annual investment of $12–16 billion projected through 2020. Over the past decade, several drivers have increased the level of transmission investment needed to maintain a reliable and economically efficient transmission system, including replacing and upgrading aging infrastructure, load growth, and changes in the generation fleet, especially renewable development. According to NERC, reliability needs remains the primary justification of new transmission builds, which accounts for 59% of new transmission projects in Figure 34. The integration of new renewable generation capacity is the second most common driver.[146]

Figure 34
Primary Driver for New Transmission Projects



Source: NERC, 2013 Long-Term Reliability Assessment, December 2013, p. 13.

In this section, we review the most important trends that are driving transmission investment, primarily through 2020.

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145 Executive Office of the President, *Economic Benefits Of Increasing Electric Grid Resilience To Weather Outages*, August 2013. Available at: http://energy.gov/sites/prod/files/2013/08/f2/Grid%20Resiliency%20Report_FINAL.pdf.

146 NERC, 2013 Long-Term Reliability Assessment, December 2013, p. 13. Available at: http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2013_LTRA_FINAL.pdf.

1. Replacing and Upgrading Aging Infrastructure

The transmission network is a system of components built over time to connect generation with load. A significant amount of new equipment was added to the system in the 1960s and 1970s that has now been in service for 40 to 50 years and is reaching the end of its useful lives. Much of the equipment installed during those years will require replacement and/or upgrading to maintain system reliability.[147]

While the life expectancy of transformers and other major equipment is more closely linked to how the equipment is operated and maintained, the age of transmission equipment can be indicative of the need for upgrades. Analysis of the age of transmission lines in the U.S. shows the number of circuit miles that may need to be upgraded or replaced doubling from 2010 to 2020 and remaining high through 2040, as shown in Figure 35. Replacing or upgrading all transmission lines that are at least 50 years old is estimated to require $5–14 billion of annual investments through 2040, assuming for the sake of analysis that 25% of facilities are replaced after every additional 10 years in operation beyond 50 years.[148]

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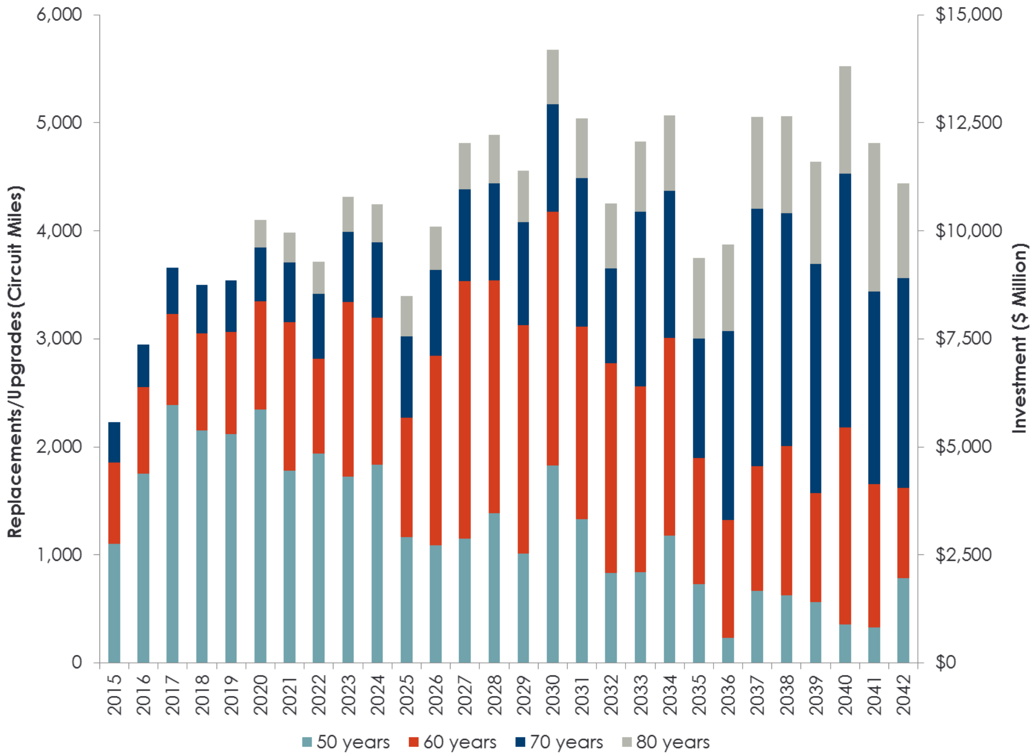
[147] As noted on Figure 31 above, during this period there was a significant increase in major baseload generation capacity additions and in NERC-coordinated construction of regional interties between major utilities to improve reliability in response to blackouts.

[148] The analysis of aging facilities is based on an assumption that transmission infrastructure tends to operate for 50 – 80 years before being replaced or upgraded. We note however that not all equipment will be replaced in this timeframe with the need for upgrades based on operation rates and patterns, the level of maintenance, and other factors concerning new replacement technology.

Figure 35
Projected Circuit Miles to be Replaced/Upgraded and Total Required Investment

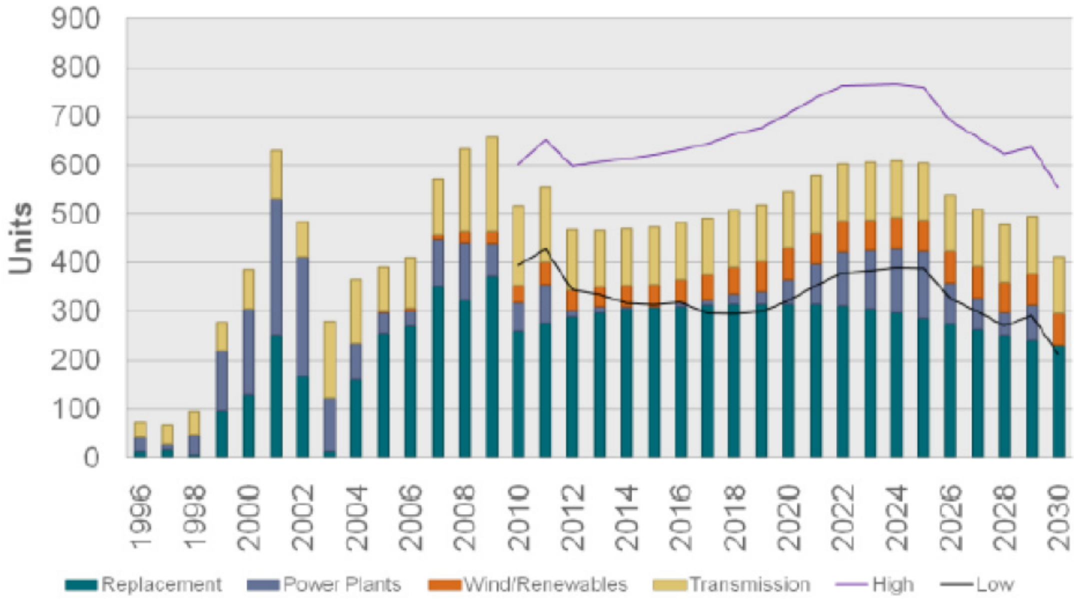


Sources and notes: The Brattle Group analysis by Johannes Pfeifenberger, Judy Chang, and John Tsoukalis of circuit miles of overhead electric lines from EEI's Historical Statistical Yearbook. Data excludes REA cooperatives. The analysis assumes that 25% of all facilities will need to be replaced after 50, 60, 70, and 80 years in service. The bars correspond to both axis based on the assumption that each circuit mile replaced/upgraded will cost on average $2.5 million per mile.

In addition, a DOE report projects large power transformers (LPT) demand will range from 400–600 units through 2025, as shown in Figure 36, which is expected to require annual investment of approximately $2–3 billion.[149]

[149] DOE, Office of Electricity Delivery and Energy Reliability, Infrastructure Security and Energy Restoration (DOE/OE/ISER) *Large Power Transformers and the U.S. Electric Grid*, June 2012. Available at: http://energy.gov/sites/prod/files/Large%20Power%20Transformer%20Study%20-%20June%202012_0.pdf. The calculation of future market size assumes a $5 million cost per LPT, based on a range of $2–7.5 million for LPT with a megavolt ampere (MVA) rating between 75 MVA and 500 MVA on page 29. The report notes that these estimates were Free on Board (FOB) factory costs, exclusive of transportation, installation, and other associated expenses, which generally add 25 to 30 percent to the total cost. The demand drivers for future LPT include aging of power transformers, transmission expansion to integrate solar and wind renewable sources, electric reliability improvements, and new capacity addition in thermal and nuclear power generation.

Figure 36
Demand Growth for Large Power Transformers in the U.S. through 2030



Source: DOE, Office of Electricity Delivery and Energy Reliability, Infrastructure Security and Energy Restoration (DOE/OE/ISER) Large Power Transformers and the U.S. Electric Grid, June 2012. The figure only includes large power transformers with a capacity rating greater than or equal to 100 MVA.

2. Demand Patterns Are Changing

Load growth and the need to deliver new sources of generation to serve the growing load have traditionally been the main drivers of transmission network expansions and associated investments. As the quantity and shape of electricity loads have evolved over time, new generation and transmission facilities were built to meet the need of customers. Future changes in load and the shifts of the geographical locations of load will inevitably continue to impact the patterns of energy flow across the transmission network, which will require system planners and engineers to constantly analyze the potential future needs of the system.

Since the economic downturn of 2008, the demand growth for electricity usage has dramatically decreased, as discussed in the Background section. NERC estimates that the 10-year compound annual growth rates for on-peak summer demand from 2014–2023 is 1.23%, an all-time low, due to a combination of slower economic growth, increased participation in energy efficiency and demand response programs, energy efficiency gains from new appliance standards, and additional reliance on behind-the-meter.[150]

The draft 2014 National Electric Transmission Congestion Study highlights the impact that low economic growth and implementation of energy efficiency has on reducing transmission

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[150] NERC, 2013 Long-Term Reliability Assessment, December 2013, p. 7. Available at: http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2013_LTRA_FINAL.pdf.

congestion and its economic costs across the country.[151] That study states that the slow economic recovery has reduced electricity usage and limited congestion in places where congestion may have been more severe otherwise.

The reduction in load over time has also led to the cancellation of several transmission projects as transmission planners' analyses no longer identify a need for the lines to meet standard reliability criteria. For example, in its 2011 Regional Transmission Expansion Plan (RTEP) PJM cancelled the 275-mile Potomac-Appalachia Transmission Pathway and the 152-mile Mid-Atlantic Power Pathway lines,[152] which were expected to cost a combined $3 billion based on the initial analysis in the 2010 RTEP.[153]

Projecting future load growth is becoming a more difficult task as energy efficiency investments and appliance efficiency standards continue to impact load. ERCOT recently updated their load projection to better account for the fact that energy efficiency is expected to have a greater impact in the future than it has in the past. The change in methodology led to a 3,800 MW, or 5%, reduction in projected load in 2020.[154] ISO-NE incorporates the energy efficiency capacity that has cleared its Forward Capacity Market through 2017 and developed projections for 2018–2023 to inform its load projections.[155] Analysis of PJM's current load forecast methodology found that PJM potentially overestimates 2020 peak load by 4,000 MW by not fully considering the impact energy efficiency will have in the future.[156]

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151 DOE, Office of Electricity Delivery and Energy Reliability, National Electric Transmission Congestion Study, Draft for Public Comment, August 2014, p. xviii. Available at: http://www.energy.gov/oe/downloads/national-electric-transmission-congestion-study-draft-public-comment-august-2014

152 PJM, 2011 PJM Regional Transmission Expansion Plan Report, February 28, 2012, download available at http://www.pjm.com/documents/reports/rtep-documents/2011-rtep.aspx.

153 PJM, "2010 PJM Regional Transmission Expansion Plan Report," February 28, 2011, Section 5 and Section 6. Available at: http://www.pjm.com/documents/reports/rtep-documents/2010-rtep.aspx.

154 Calculated based on May 2013 and May 2014 versions of the *Report on the Capacity, Demand, and Reserves in the ERCOT Region*, ERCOT, Reserve Adequacy, downloads available at http://www.ercot.com/gridinfo/resource.

155 ISO New England, Inc., System Planning, *ISO-NE Energy-Efficiency Forecast Report for 2018 to 2023*, June 3, 2014, available at

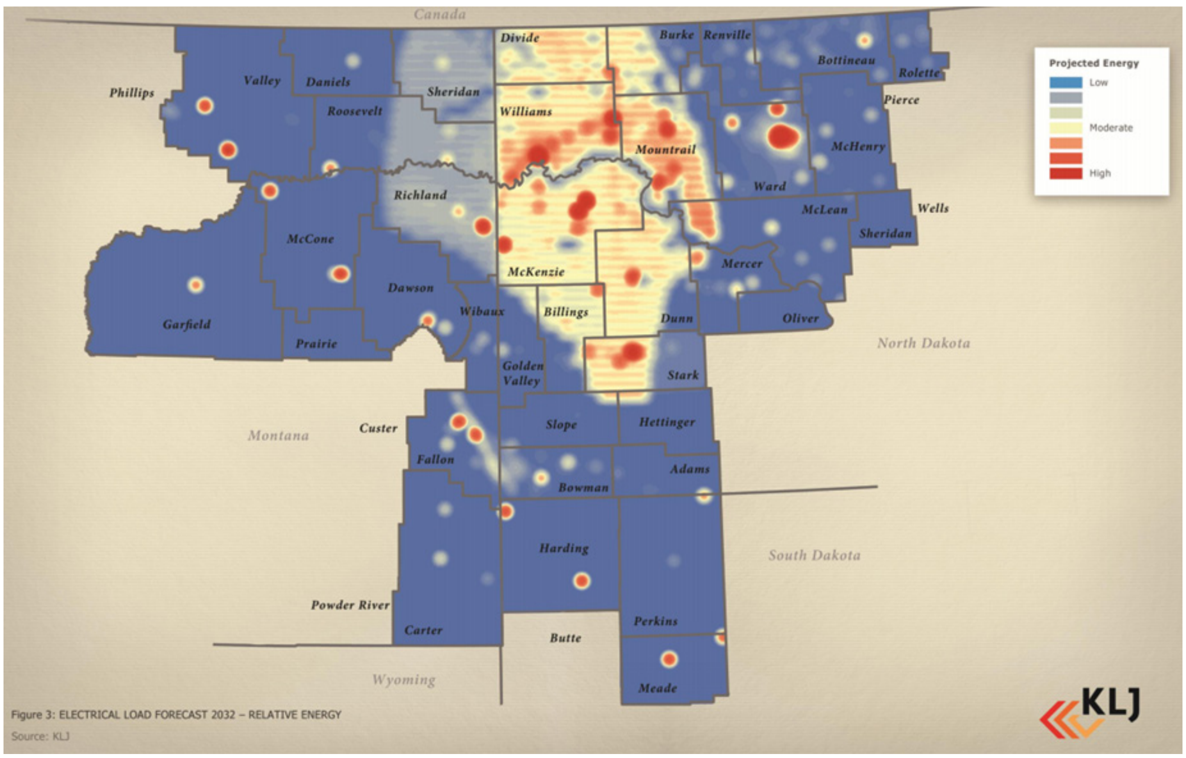
http://www.iso-ne.com/static-assets/documents/2014/08/eef_report_2018_2023_final.pdf.

156 Faruqui, A., S. Sergici, and K. Spees, "Quantifying the Amount and Economic Impacts of Missing Energy Efficiency in PJM's Load Forecast," prepared for the Sustainable FERC Project, September 2014, available at

http://www.brattle.com/system/publications/pdfs/000/005/080/original/Quantifying_the_Amount_and_Economic_Impacts_of_Missing_Energy_Efficiency_in_PJMs_Load_Forecast.pdf?1411401772. The report estimated the benefits of lower energy and capacity prices due to fully accounting for energy efficiency is $433 million per year in the near term, but did not estimate the value of avoided transmission and distribution investments.

Some parts of the U.S., particularly in oil and gas-rich regions, are experiencing growing demand for electricity from oil and gas activities that will require additional generation resources and transmission in the next five to ten years to serve the growing demand. These regions include the Bakken formation in North Dakota and Montana, as well as the Permian Basin in Texas and New Mexico. A load forecast analysis for the North Dakota Transmission Authority was completed in 2012 to support transmission development in North Dakota, South Dakota, and Montana due to oil and gas activity in the Williston Basin, which includes the Bakken formation. The study found that projected load in 2032 will be 2,500 MW higher than current load (representing 208% growth) due to the addition of 30,000 wells within the region, as shown in Figure 37.[157]

Figure 37
Load Growth Projected in Williston Basin



Source: Kadrmas, Lee & Jackson, Inc., Power Forecast 2012: Williston Basin Oil and Gas Related Electrical Load Growth Forecast, October 2012.

New uses of electricity, such as the penetration of electric vehicles (EV), may materialize in future years that could require additional transmission investment. However, new load for EVs may not require significant transmission build out. For example, the California Energy Commission 2024 load forecast includes a high EV penetration case that assumes for each additional 1 million EVs on the road in California the total annual energy growth will be 2,400

[157] Kadrmas, Lee & Jackson, Inc., *Power Forecast 2012: Williston Basin Oil and Gas Related Electrical Load Growth Forecast*, October 2012, available at http://kljeng.com/wp-content/uploads/2012/12/PF12-to-print-for-public.pdf

GWh (0.8% of 2020 load in California) and peak load will increase by 104 MW (0.2% of 2020 peak).[158] As EVs are expected to be concentrated in urban areas, local upgrades may nonetheless be needed in areas with the highest rates of adoption to maintain reliability and reduce congestion in those areas.

3. Generation-Related Transmission Needs

As discussed in the Background section, the generation resource mix in the U.S. has recently undergone significant changes due to the economics of new build power generation largely driven by sustained low natural gas prices, environmental regulations that require coal plants to retrofit emissions control equipment or retire, and state-level mandates and federal subsidies for renewable capacity. Looking forward, the generation mix will continue to adapt to changes in market conditions and environmental regulations, especially to greenhouse gas regulations such as those in the Clean Power Plan proposed by the EPA in June 2014.[159] The continued changes in the U.S. generation mix will have a significant impact on future projected investment in the transmission system.

The change in generation mix caused by the retirement of large, baseload coal and nuclear plants and the growth of natural gas-fired capacity will lead to the need for continuous analysis of new power flows across the system and contingencies. For example, in the 2012 RTEP, PJM analyzed the impacts of nearly 14 GW of units that are expected to retire based on Deactivation Notifications submitted from November 2011 through December 2012, as shown in Figure 38. PJM identified the need for $2.4 billion in transmission investment due to the changes in power flows caused by the retirements.[160]

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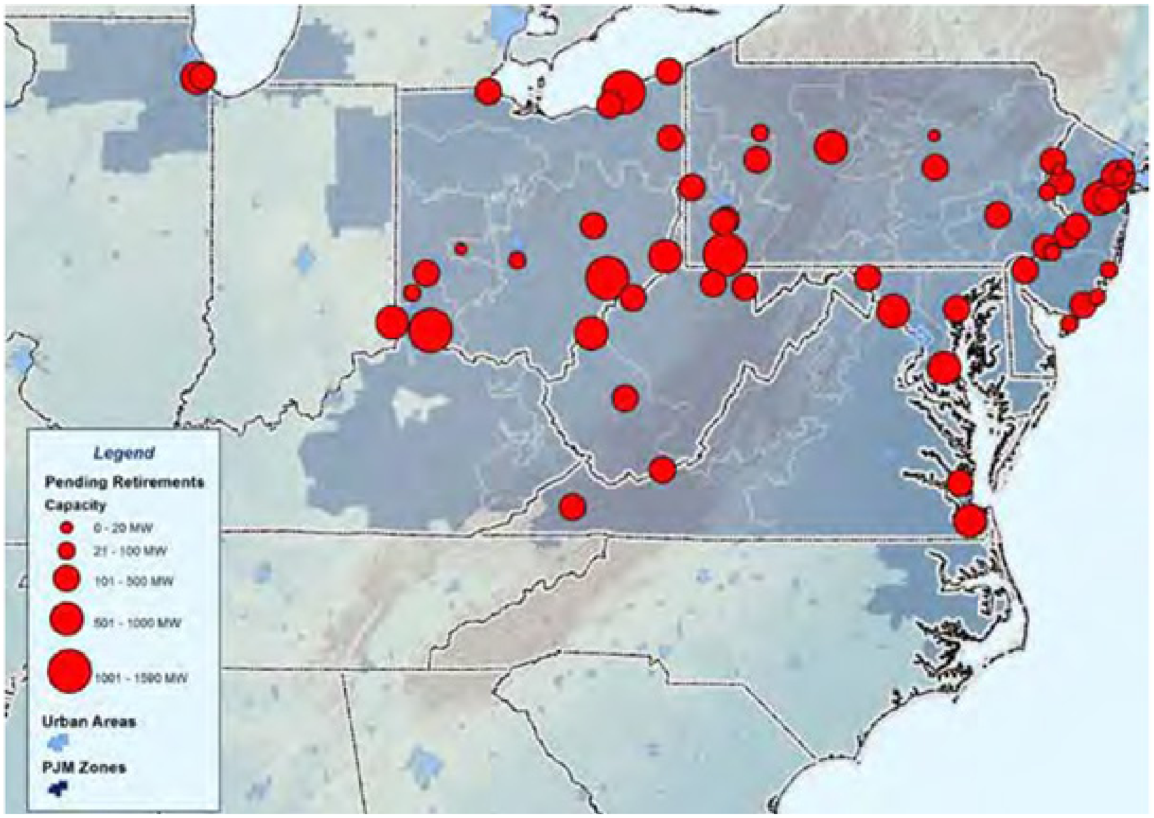
[158] California Energy Commission, *California Energy Demand 2014—2024 Final Forecast, Volume 1: Statewide Electricity Demand, End-User Natural Gas Demand, and Energy Efficiency*, Commission Final Report, CEC-200-2013-004-V1-CMF, January 2014, available at http://www.energy.ca.gov/2013publications/CEC-200-2013-004/CEC-200-2013-004-V1-CMF.pdf.

[159] For more information on the Clean Power Plan, see: http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule

[160] PJM, 2012 PJM Regional Transmission Expansion Plan Report, February 28, 2013, Book 3, p. 17. Available at http://www.pjm.com/documents/reports/rtep-documents/2012-rtep.aspx. The plants are expected to retire over four years from 2012 to 2015. "These analyses identified the need for more than 130 upgrades comprising a range of solutions: line terminal equipment upgrades, new substations and substation additions to reinforce underlying systems, existing line rebuilds to achieve higher line ratings as well as new transmission lines."

Figure 38
Summary of Deactivation Notifications Received by PJM (Nov 2011–Dec 2013)



Source: PJM, 2013 PJM Regional Transmission Expansion Plan Report, February 28, 2014, Book 1, p. 6.

MISO and the Southwest Power Pool (SPP) are also regions where changes in the fossil and nuclear generation mix are expected to be significant.[161] Recently, SPP highlighted that the proposed EPA greenhouse gas standards on existing fossil generation units could result in coal and gas-fired generation retirements increasing from 3 GW to 9 GW within its footprint by 2020.[162]

The growth of renewable capacity, as described in the Background section, has resulted in new challenges for both planning and operating the transmission system and the overall electric power sector. RTOs and NREL have completed renewable integration studies over the past decade to understand the impacts that increasing onshore wind, and more recently solar, capacity will have on the transmission network.[163] Meeting state Renewable Portfolio Standards

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161 See Background section for more details.

162 SPP, "SPP's Reliability Impact Assessment of the EPA's Proposed Clean Power Plan," October 8, 2014, available at http://www.spp.org/publications/CPP%20Reliability%20Analysis%20Results%20Final%20Version.pdf

163 Recent examples of analyses with high penetration of renewables include PJM's analysis of its RPS mandates and 30% renewables in PJM, Renewable Integration Study Reports, March 2014, download available at http://www.pjm.com/committees-and-groups/task-forces/irtf/pris.aspx; and NREL's third phase of the Western Wind and Solar Integration Studies in NREL, Transmission Grid Integration,

Continued on next page

(RPS) mandates has also been integrated into transmission planning processes in many regions, with the different regional approaches for building transmission lines to connect renewable capacity discussed further in the next section. One of the largest transmission investments specifically for integrating renewables has occurred in Texas from 2009 to 2014 through the Energy Zones (CREZ) process, which resulted in $6.9 billion in investment with the goal of providing capacity for 18.5 GW of wind farms.[164]

Additional transmission investments will be particularly important for continued growth of onshore wind capacity due to the distance between the highest quality resources located in the interior of the country and load centers along the coasts. The amount of transmission necessary in the future to connect to these resources will depend on whether onshore wind capacity continues to be built beyond the current RPS mandates and without the federal production tax credit. In cases where additional onshore wind capacity is pursued, the costs of additional transmission facilities may lead to the development of wind resources that are lower quality but closer to load. In its Regional Generation Outlet Study, MISO analyzed whether the additional transmission lines provide a lower cost solution to meeting the RPS mandates in their states, finding that a combination of local and regional projects will results in the lowest costs, as shown in Figure 39.[165]

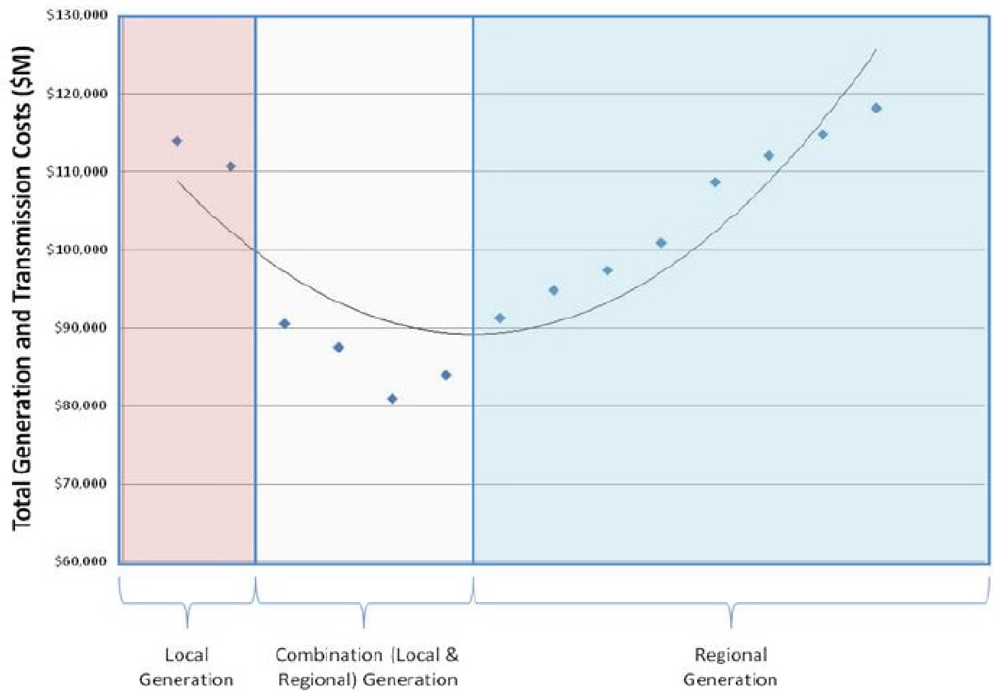
Continued from previous page

Western Wind and Solar Integration Study, download available at http://www.nrel.gov/electricity/transmission/western_wind.html.

164 RS&H, CREZ Progress Report No. 16 (July Update), Competitive Renewable Energy Zone Program Oversight, prepared for Public Utility Commission of Texas, July 2014. Available at http://www.texascrezprojects.com/page2960323.aspx.

165 Midcontinent ISO (MISO), *Multi Value Project Portfolio: Results and Analyses*, January 10, 2012. Available at: https://www.misoenergy.org/Library/Repository/Study/Candidate%20MVP%20Analysis/MVP%20Portfolio%20Analysis%20Full%20Report.pdf.

Figure 39
MISO Analysis of Total Renewable Generation and Transmission Costs



Source and notes: Midcontinent ISO (MISO), Multi Value Project Portfolio: Results and Analyses, January 10, 2012. The x-axis represents the distance renewable generation capacity is located from load.

Onshore wind will also face competition from other zero-carbon generation technologies in meeting public policy goals, such as solar PV, which has seen significant reductions in costs and increases in installed capacity in recent years and large hydroelectric generation projects, which are primarily located in Canada. For example, California has recently seen significantly more development of solar resources than wind resources such that the California RPS is projected to be met in 2020 with 45% of the Renewable Energy Credits (RECs) generated by solar technologies, as shown in Figure 40.[166]

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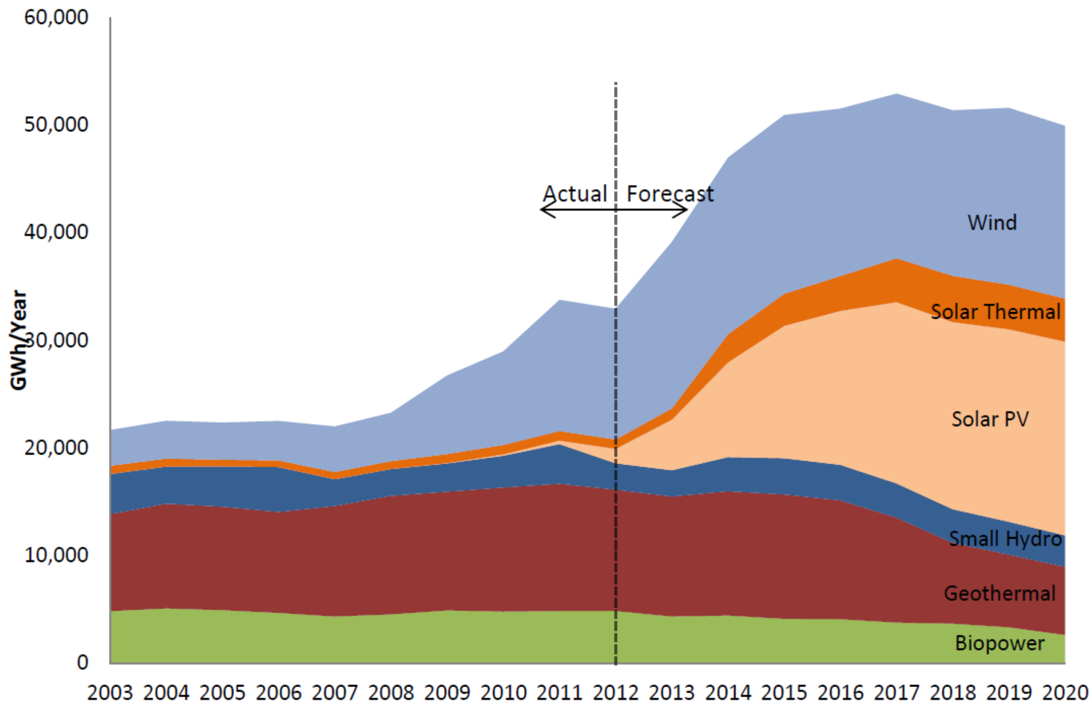
[166] California Public Utilities Commission, *Renewables Portfolio Standard, Quarterly Report: 4th Quarter 2013*, n.d., p. 6. Available at: http://www.cpuc.ca.gov/NR/rdonlyres/71A2A7F6-AA0E-44D7-95BF-2946E25FE4EE/0/2013Q4RPSReportFINAL.pdf.

Figure 40
California Renewable Resource Mix to Meet 33% RPS



Source: California Public Utilities Commission, Renewables Portfolio Standard, Quarterly Report: 4th Quarter 2013, n.d., p. 6.

Offshore wind may provide a potentially less transmission-intensive renewable generation alternative (in terms of circuit-miles built) to onshore wind if offshore technology that is located close to load centers, especially along the east coast, becomes cost competitive with other renewable technologies. The first offshore wind capacity is currently scheduled to be built in New England over the next few years and has been proposed in other locations along the east coast.[167] In its transmission planning, PJM included different scenario for meeting its RPS mandates, including one scenario with 7 GW of offshore wind capacity while all scenarios accounted for the 1 GW of offshore wind currently in its interconnection queue.[168] While the currently planned offshore wind farms only include a generation lead line for interconnecting into the existing transmission network, a network of subsea HVDC transmission lines has been proposed to connect 6,000 MW of offshore wind capacity to the transmission network.[169]

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167 Deepwater Winds's Block Island Wind Farm (29 MW) is currently listed in the ISO-NE Generator Interconnection Queue, received all needed financing in March 2015, and is expected to be operational by the summer of 2016. (See ISO-NE Interconnection Request Queue online at: http://www.iso-ne.com/system-planning/transmission-planning/interconnection-request-queue.).

168 PJM, 2013 PJM Regional Transmission Expansion Plan Report, February 28, 2014, Book 4, p. 18. Available at: http://www.pjm.com/documents/reports/rtep-documents/2013-rtep.aspx.

169 For more information, see Atlantic Wind Connection, Atlantic Wind Connection Project Summary, online at http://atlanticwindconnection.com/home.

D. Planning the Future Transmission Network

The drivers discussed in the previous section will play key roles in how the transmission network will need to adapt in the future. The responsibility for understanding and planning for how each driver impacts a specific transmission network lies with the utilities and RTOs. To maintain the level of service that is required of the electric system, the transmission network will need to adapt to these changes as they occur. The system is currently undergoing significant upgrades across the country to respond to the changes already underway through the existing transmission planning process.

FERC incentives (*e.g.*, higher return on equity for cost recovery) have continued to make building new transmission projects an economically favorable objective of both incumbent utilities and independent transmission developers. However, transmission lines are only built if there is either a need identified through the planning processes at utilities and RTOs or if merchant developers propose them. Due to the cost (often more than $2 million per mile), length (from several miles to hundreds of miles in length), and potential impact on the local environment and communities, transmission projects will continue to require considerable time and effort to be proposed, approved, permitted, sited, and built. Through efforts at the local, regional, and federal level, opportunities for improving the process throughout the transmission development cycle are being pursued, such as FERC Order No. 1000.

The remainder of this section provides a summary of the processes used by planning authorities throughout the U.S. for identifying the need for new transmission, followed by a discussion of changes currently occurring in the planning, permitting, and siting processes that aim to improve how transmission gets built.

1. Overview of Transmission Planning

Transmission planning is a detailed, technical, and collaborative process that requires the use of a range of tools, such as load projections, market simulations with uncertain fuel prices, and power flow analyses, over vast networks. Transmission networks are planned by planning authorities within each NERC region that have the responsibility to maintain both the reliability and economic efficiency of administered markets. The U.S. planning authorities differ widely across the country with some as small as municipalities (*e.g.*, Seattle City Light) and others as large as RTOs (*e.g.*, PJM).[170]

The planning processes and requirements can vary significantly based on the size of the planning authority, state-level public utility commission regulations, and whether or not a utility is a member of an RTO. Certain aspects of planning and operation can be regulated by state public utility commissions and other aspects overseen by the FERC. Planning processes generally include an assessment of reliability violations and overloads based on NERC standards and regional criteria, analysis of whether the economic value of a transmission investment justifies

[170] A list of currently active planning authorities registered with NERC is available at http://www.nerc.com/pa/comp/Pages/Registration-and-Certification.aspx.

the costs, and, at the state or regional-level, analysis of the incremental transmission needs for meeting public policy objectives, such as Renewable Portfolio Standards.

Each transmission system operator or RTO has its own process for identifying potential lines and determining whether their construction is justified that are consistent with NERC and regional entity standards.[171] When issues are identified that will violate the reliability standards, transmission engineers identify the least cost approach for removing the violations. Justification of building new transmission lines for economic purposes, such as removing congestion and reducing capacity costs, requires a more detailed cost-benefit analysis to be completed, which tend to be less standardized across regions. Building new transmission to access renewable generation resources and facilities often go through alternative planning processes that balance policy goals with the cost impacts to ratepayers, all of which are further discussed below.

As an example of the complexity and challenges of transmission planning, the Southwest Power Pool (SPP) completes a series of transmission planning studies on a three-year cycle, termed the Integrated Transmission Planning studies, or ITP. The SPP ITP process includes a near-term study (ITPNT), a ten-year study (ITP10), and a twenty-year study (ITP20): the ITPNT study is completed on an annual basis; the ITP10 was first released in 2012 and the 2015 version is currently underway; and the first ITP20 study was released in 2013 and is also completed triennially.[172] Each ITP study works off the previous studies to analyze the transmission needs in the region and utilizes future scenarios that consider a range of uncertainties, including wind development and environmental regulations. In addition to the ITP process, SPP conducts "high priority" studies based on stakeholder requests to assess the reliability and economic impact of proposed changes to the transmission system. As an example, SPP completed the High Priority Incremental Load Study in 2014 to analyze the transmission needs "in response to concerns about oil and gas shale play developments, and other future load additions in the region that had not been accounted for in previous planning efforts."[173]

The SPP studies incorporate input from stakeholders, including representatives from transmission owners, local utilities, and state utility commissions or boards, through several working groups and task forces, as shown on the left in Figure 41, who provide input on the technical details and accuracy of the planning process, future scenarios, modeling assumptions, metrics for analyzing potential solutions, and recommended solutions.[174] In addition, the

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171 All processes have the same objective of adhering to reliability criteria set forth by NERC. RTOs may have additional criteria for added reliability margins, but those additional criteria are also consistent with NERC criteria.

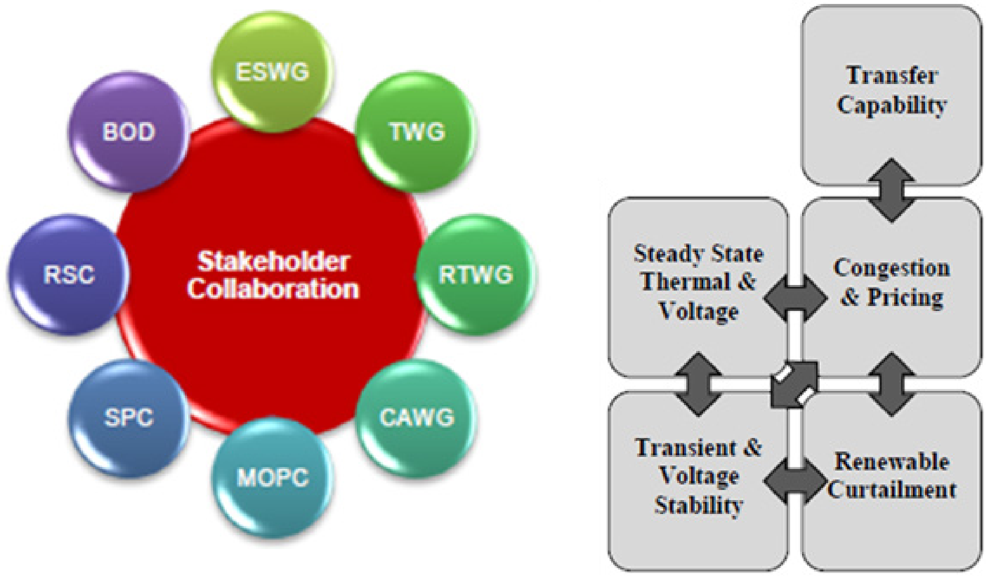
172 SPP, Integrated Transmission Planning, 2015, online at: http://www.spp.org/section.asp?pageID=129

173 SPP HPILS Task Force, High Priority Incremental Load Study Report, April 2, 2014, p. 8. Available at: http://www.spp.org/section.asp?group=2766&pageID=27.

174 The stakeholder groups included in Figure 41 are: Economic Studies Working Group (ESWG), Transmission Working Group (TWG), Regional Tariff Working Group (RTWG), Cost Allocation Working Group (CAWG), Markets and Operations Policy Committee (MOPC), Strategic Planning Committee (SPC), Regional State Committee (RSC), Board of Directors (BOD).

detailed modeling of the transmission system requires several different analyses to work together to meet the reliability, stability, policy, and economic needs of the system in each case analyzed, as shown on the right in Figure 41.[175]

Figure 41
SPP Coordination of Stakeholder Collaboration and Technical Analyses for Transmission Planning



Source: SPP Engineering, 2012 Integrated Transmission Plan 10-Year Assessment Report, January 31, 2012. The acronyms stand for the following: Economic Studies Working Group (ESWG), Transmission Working Group (TWG), Regional Tariff Working Group (RTWG), Cost Allocation Working Group (CAWG), Markets and Operations Policy Committee (MOPC), Strategic Planning Committee (SPC), Regional State Committee (RSC), Board of Directors (BOD).

Approved by FERC in 2010, the SPP ITP is expected to "continue to mature through each successive cycle" and is just one example of how a regional planning organization structures its planning process.[176] In Texas, ERCOT has established a process through its Regional Planning Group for studying transmission needs in the near-term through its Regional Transmission Plan, which is completed every year and looks six years forward, and in the long-term with its Long-Term System Assessment, which is completed every other year and looks 10–20 years forward. Regional entities continue to adapt their planning processes based on requirements under Order 1000, which are discussed further in a later section.

The larger interconnections in the U.S. also completed interconnection-wide transmission planning for advisory purposes under grants from the U.S. Department of Energy, with all three continuing such planning under their own funding. In WECC, balancing authorities throughout the Western Interconnection complete their own local reliability analyses and collaborate in an

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175 SPP Engineering, 2012 Integrated Transmission Plan 10-Year Assessment Report, January 31, 2012. Available at: http://www.spp.org/publications/20120131%202012%20ITP10%20Report.pdf.

176 *Id.*, p. 16.

interconnection-wide analysis.[177] The RTOs and balancing authorities in the Eastern Interconnection have begun to collaborate on an interconnection-wide basis through the Eastern Interconnection Planning Collaborative, which was initiated in 2010 through a grant from the U.S. Department of Energy.[178]

2. Justifications for Investments in the Future Transmission System

a. Maintaining a Reliable Network

As discussed above, NERC set reliability standards for maintaining a secure supply of electricity to all consumers. There are currently in place well-established processes for reliability-driven transmission planning that requires engineering analyses based on well-defined cases to first identify and then address reliability violations, such as the so-called "N-1" criteria violations, as determined by NERC. These reliability standards provide the utility and regional transmission planners clear criteria, which lead to the development of well-honed formulaic evaluation processes that use established analytical tools (such as power flow models and dynamic network models for stability analyses) to identify future reliability violations and solutions for avoiding these violations through transmission upgrades or non-transmission alternatives. Load growth, shifts in geographical uses of electricity, and changes in the generation fleet are the most common drivers for reliability violations.

NERC lists five standards that are subject to enforcement, which form the basis of the engineering analyses for planning a reliable transmission system. These standards specify that the system must be operated in a safe, reliable fashion and can tolerate the outage of one or more transmission or generation elements.[179]

The assigned planning authority and transmission planners analyze their systems based on these standards and identify potential reliability violations that, if they occurred on the existing system, may lead to load-shedding events, such as brownouts or rolling blackouts.

Two examples of regions with significant reliability upgrades currently in development include CAISO and ISO-NE. CAISO in its 2013–2014 Transmission Plan identified a total of 28 transmission projects to maintain reliability with an estimated total cost of $1.7 billion. The projects include three lines required in southern California due to the retirement of the San Onofre Nuclear Generation Station and the potential retirement of gas-fired generation.[180] New

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177 For more information, see: Western Electricity Coordinating Council (WECC), Transmission Expansion Planning Policy Committee, online at https://www.wecc.biz/teppc/Pages/Default.aspx.

178 For more information, see Eastern Interconnection Planning Collaborative (EIPC), online at http://www.eipconline.com/.

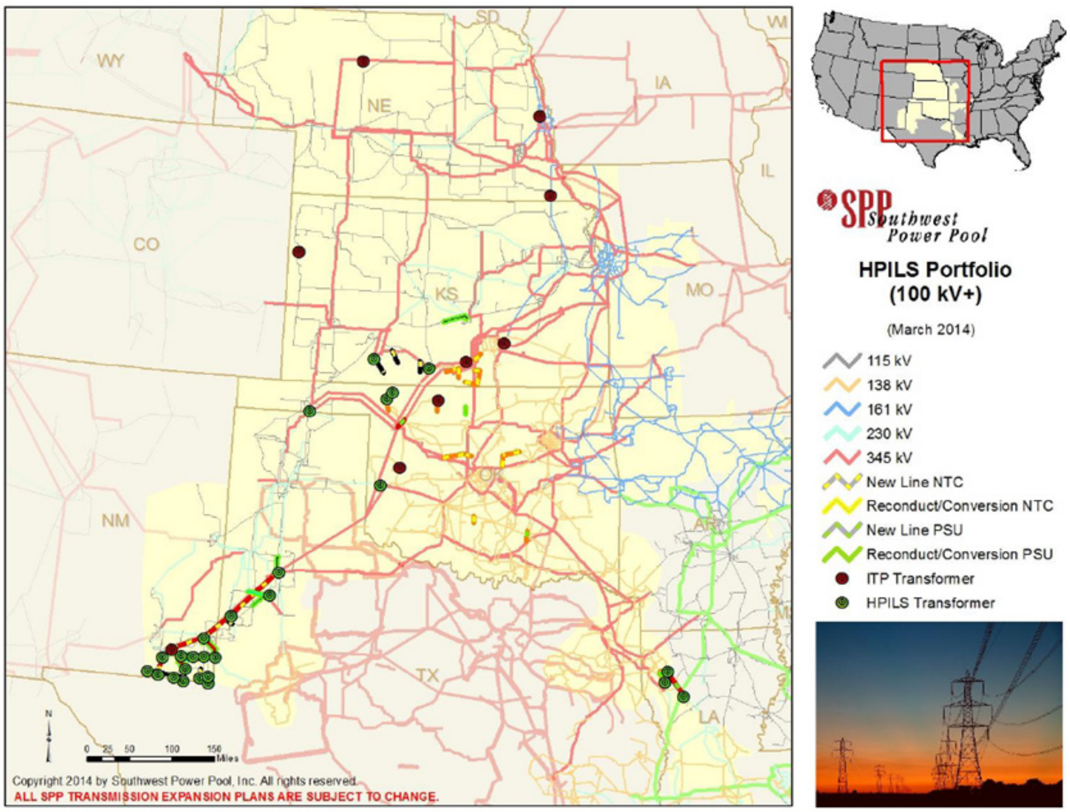
179 NERC, Reliability Standards for the US Bulk Electric System of North America, Updated September 17, 2014.

180 CAISO, 2013–2014 Transmission Plan, July 16, 2014. Available at: http://www.caiso.com/planning/Pages/TransmissionPlanning/2013-2014TransmissionPlanningProcess.aspx.

England is currently undergoing several reliability upgrades, including the Maine Power Reliability Project (MPRP) and New England East-West Solution (NEEWS), which account for $3 billion of the currently planned $4.5 billion in transmission projects in the region.[181]

SPP is an example of a region experiencing increased demand for electricity primarily in oil-rich regions along the border between Texas and New Mexico. Due to concern about load growth that had not yet been considered in its planning process, SPP completed a High Priority Incremental Load Study (HPILS) to identify upgrades required to reliably meet future needs.[182] The analysis led to approval of $1.5 billion in projects, as shown in Figure 42.[183]

Figure 42
SPP High Priority Incremental Load Study Portfolio



Source: SPP HPILS Task Force, High Priority Incremental Load Study Report, April 2, 2014.

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181 Oberlin, Brent, Regional System Plan Transmission Projects June 2014 Update, prepared for ISO New England Planning Advisory Committee Meeting, Westborough, MA, June 19, 2014. Available at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/projects/2014/final_rsp14_project_list_june_2014.pdf.

182 SPP HPILS Task Force, High Priority Incremental Load Study Report, April 2, 2014. Available at: http://www.spp.org/section.asp?group=2766&pageID=27.

183 The HPILS also recommended the removal of $573 million of projects which were found to be no longer necessary.

b. Providing Economic Benefits

While the majority of transmission investment nationally has been, and continues to be, justified by reliability concerns associated with avoiding NERC violations, transmission planning processes have adapted to include "economic" (or "market efficiency") projects, which justify the investment in new transmission infrastructure based on an analysis of whether the monetized benefits of a project justify its costs. The most commonly considered economic benefits are reductions in fuel and other variable costs (known as production cost savings), or the reduction in wholesale electricity market prices (known as load payment savings), both of which are estimated by simulating the system under the same conditions both with and without the line.

Although a wider range of economic benefits of building new transmission exist, currently only a limited set of those benefits are considered by transmission planners across the U.S. Many RTO regions have adopted processes for economic or market efficiency projects that tend to be limited to evaluating the production cost savings that result from reduced congestion. NYISO, ISO-NE, ERCOT, and PJM are regions that remain solely focused on quantifying production cost savings in their economic analyses. MISO and CAISO, as will be discussed later, have considered a wider set of benefits for certain projects, or portfolio of projects, but do not do so in their regular transmission planning processes in which they primarily still use production cost savings as the main economic benefit. Calculating economic benefits based solely on reductions in production costs however have not resulted in any new transmission lines being built.[184]

Estimating the production cost savings only captures a portion of the total economic benefits that new transmission investment can provide on a societal level. For example, an analysis of the benefits that the Paddock-Rockdale line in Wisconsin proposed and developed by American Transmission Company (ATC), as shown in Figure 43, estimated the net present value of total benefits to be $220 million compared to just $80 million in production cost savings for a line with estimated costs of $137 million.[185] In this case, production cost savings alone would not have resulted in the positive net benefits necessary for justifying the line to be built. However, further analysis of loss benefits and refunds, firm transmission rights and congestion benefits, competitiveness benefits, insurance benefits during system failure, and capacity savings from reduced loss resulted in benefits estimated to be 60% above the cost of the project on a net present value basis.

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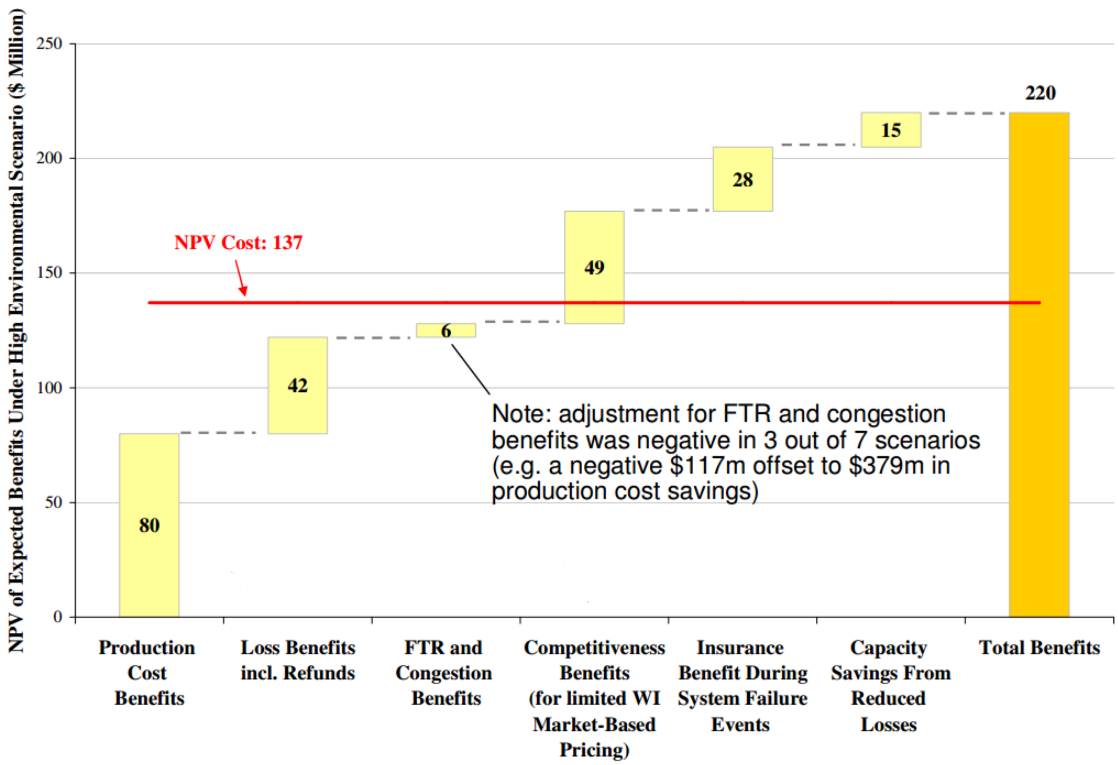
184 Congestion is often used by planning authorities as an indicator of potential need for both reliability and economic upgrades. However, resolving congestion alone (and the associated reduction in production cost savings) has rarely, if ever, been used to justify any significant transmission projects.

185 Pfeifenberger, Johannes and Delphine Hou, in conjunction with the Working group for Investment in Reliable and Economic Electric Systems (WIRES), *Employment and Economic Benefits of Transmission Infrastructure Investment in the U.S. and Canada*, May 2011. Available at

http://www.brattle.com/system/publications/pdfs/000/004/501/original/Employment_and_Economic_Benefits_of_Transmission_Infrastructure_Investmt_Pfeifenberger_Hou_May_2011_WIRES.pdf?1378772110.

Figure 43
Total Economic Benefits Quantified for ATC Paddock-Rockdale Project



Source: Pfeifenberger, Johannes and Delphine Hou, in conjunction with the Working group for Investment in Reliable and Economic Electric Systems (WIRES), Employment and Economic Benefits of Transmission Infrastructure Investment in the U.S. and Canada, May 2011.

Based on a review of the approaches and metrics considered by transmission planners across the country, Table 6 shows a list of potential transmissions benefits for planners to consider in developing new transmission plans.

The benefits exist regardless of the regulatory system:

> *Despite the differences among regions in how they consider transmission benefits in planning, the same set of potential transmission benefits applies regardless of the specific market or geographic location. The magnitudes of benefits associated with transmission investments depend on the market conditions and the physics of electric power flows, and not on the regulatory framework under which the investments are made.*[186]

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[186] Chang, Judy W., Johannes P. Pfeifenberger, and J. Michael Hagerty, *A WIRES Report on the Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments*, July 2013, p. iii. Available at: http://www.brattle.com/system/publications/pdfs/000/004/807/original/The_Benefits_of_Electric_Transmission_-_Identifying_and_Analyzing_the_Value_of_Investments_Chang_Pfeifenberger_Hagerty_Jul_2013.pdf?1378772131.

Table 6
Potential Benefits of Transmission Investments

Benefit Category	Transmission Benefit
1. Traditional Production Cost Savings	Production cost savings as traditionally estimated
1a-1i. Additional Production Cost Savings	a. Reduced transmission energy losses
	b. Reduced congestion due to transmission outages
	c. Mitigation of extreme events and system contingencies
	d. Mitigation of weather and load uncertainty
	e. Reduced cost due to imperfect foresight of real-time system conditions
	f. Reduced cost of cycling power plants
	g. Reduced amounts and costs of operating reserves and other ancillary services
	h. Mitigation of reliability-must-run (RMR) conditions
	i. More realistic representation of system utilization in "Day-1" markets
2. Reliability and Resource Adequacy Benefits	a. Avoided/deferred reliability projects
	b. Reduced loss of load probability or c. Reduced planning reserve margin
3. Generation Capacity Cost Savings	a. Capacity cost benefits from reduced peak energy losses
	b. Deferred generation capacity investments
	c. Access to lower-cost generation resources
4. Market Benefits	a. Increased competition
	b. Increased market liquidity
5. Environmental Benefits	a. Reduced emissions of air pollutants
	b. Improved utilization of transmission corridors
6. Public Policy Benefits	Reduced cost of meeting public policy goals
7. Employment and Economic Development Benefits	Increased employment and economic activity; Increased tax revenues
8. Other Project-Specific Benefits	Examples: storm hardening, increased load serving capability, synergies with future transmission projects, increased fuel diversity and resource planning flexibility, increased wheeling revenues, increased transmission rights and customer congestion-hedging value, and HVDC operational benefits

Source: Chang, Judy W., Johannes P. Pfeifenberger, and J. Michael Hagerty, A WIRES Report on the Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments, July 2013.

The potential value that any single transmission line will provide to the system will differ significantly from project to project. Estimating these benefits may require a different set of analytical tools and processes than those currently used by transmission planners. Accounting for the wider range of benefits will require the planners to adopt an updated framework for identifying, evaluating, approving, and allocating the costs of new transmission projects.[187]

SPP, CAISO, and MISO are planning organizations that have expanded the benefits considered in their review of transmission needs, as shown in Table 7. SPP, however, is the only RTO to incorporate a wider range of benefits in their regular planning process, as well as justify the whole portfolio of projects in each study based on economic benefits. SPP expanded their consideration of economic benefits through their Priority Projects study completed in 2010 and have continued to do so as a part of their ongoing ITP studies.[188] The benefits considered by SPP in the most recent ITP10 analysis include: adjusted production cost savings, reduction of emissions rates and values, savings due to lower ancillary service needs and production costs, avoided or delayed reliability projects, capacity cost savings due to reduced on-peak transmission losses, assumed benefits of mandated reliability projects (within the recommended portfolio), public policy benefits, mitigation of transmission outage costs, increased wheeling through and out revenues, and marginal energy losses benefits,.[189] SPP's Metrics Task Force recommended further evaluation of the potential for incorporating additional benefits into their methodology, including the reduced costs during extreme events and the reduced cycling of baseload generating units.[190]

187 A framework for incorporating the larger list of benefits outlined in Table 6 is included in Chang, Judy W., Johannes P. Pfeifenberger, and J. Michael Hagerty, A WIRES Report on the Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments, July 2013.

188 SPP, SPP Priority Projects: Phase II Report, Maintained by SPP Engineering/Planning, February 1, 2010. Available at: http://www.spp.org/publications/Priority%20Projects%20Phase%20II%20Final%20Report%20-%204-27-10.pdf

189 SPP, 2015 Integrated Transmission Plan: 10-Year Assessment Report, Engineering, January 20, 2015, p. 83. Available at: http://www.spp.org/publications/Final_2015_ITP10_Report_BOD_Approved_012715.pdf

190 SPP Metrics Task Force, Benefits for the 2013 Regional Cost Allocation Review, September 13, 2012.

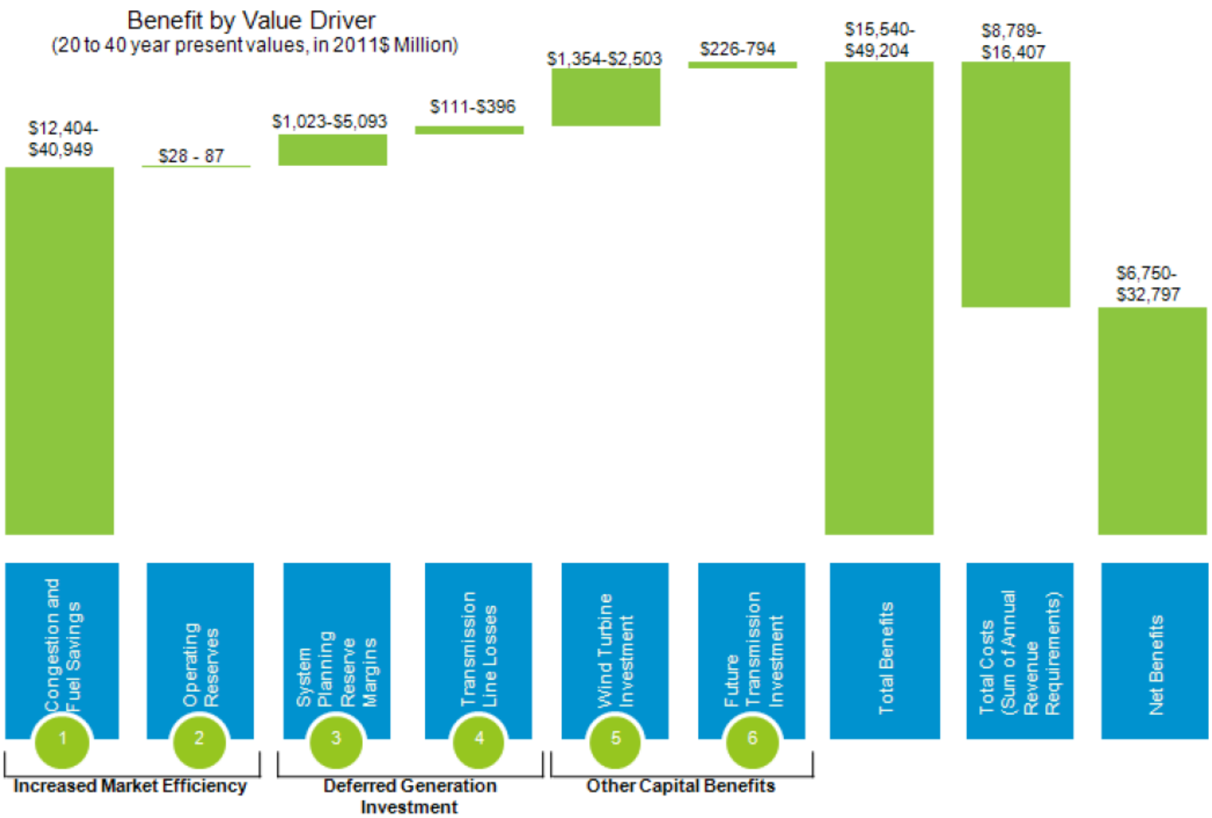
Table 7
Transmission Benefits Considered in RTO Planning Processes

RTO Planning Process	Estimated Benefits	Other Benefits Considered (without necessarily estimating their value)
CAISO TEAM (as applied to PVD2)	• Production cost savings and reduced energy prices from both a societal and customer perspective • Mitigation of market power • Insurance value for high-impact low-probability events • Capacity benefits due to reduced generation investment costs • Operational benefits (RMR) • Reduced transmission losses • Emissions benefits	• Facilitation of the retirement of aging power plants • Encouraging fuel diversity • Improved reserve sharing • Increased voltage support
SPP ITP Analysis	• Production cost savings • Reduced transmission losses • Wind revenue impacts • Natural gas market benefits • Reliability benefits • Economic stimulus benefits of transmission and wind generation construction	• Enabling future markets • Storm hardening • Improving operating practices/maintenance schedules • Lowering reliability margins • Improving dynamic performance and grid stability during extreme events • Societal economic benefits
Additional benefits recommended by SPP's Metrics Task Force	• Reduced energy losses, • Reduced transmission outage costs • Reduced cost of extreme events • Value of reduced planning reserve margins or loss of load probability • Increased wheeling through and out revenues • Value of meeting public policy goals	• Mitigation of weather uncertainty • Mitigation of renewable generation uncertainty • Reduced cycling of baseload plants • Increased ability to hedge congestion costs • Increased competition and liquidity
MISO MVP Analysis	• Production cost savings • Reduced operating reserves • Reduced planning reserves • Reduced transmission losses • Reduced renewable generation investment costs • Reduced future transmission investment costs	• Enhanced generation policy flexibility • Increased system robustness • Decreased natural gas price risk • Decreased CO_2 emissions output • Decreased wind generation volatility • Increased local investment and job creation
NYISO CARIS	• Reliability benefits • Production cost savings	• Emissions costs • Load and generator payments • Installed capacity costs • Transmission Congestion Contract value
PJM RTEP	• Reliability benefits • Production cost savings	• Public policy benefits
ERCOT LTS	• Reliability benefits • Production cost savings • Avoided transmission project costs	• Public policy benefits
ISO-NE RSP	• Reliability benefits • Net reduction in total production costs	• Public policy benefits

Source: Chang, Judy W., Johannes P. Pfeifenberger, and J. Michael Hagerty, A WIRES Report on the Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments, July 2013.

MISO approved a portfolio of seventeen Multi-Value Projects (MVP) in 2011 based on a broad set of economic benefits with total costs and benefits shown in Figure 44.[191]

Figure 44
MISO Benefit-Cost Analysis for Multi-Value Project Portfolio



Source: MISO, Multi Value Project Portfolio: Results and Analyses, January 10, 2012.

Non-RTO regions have been slower to adopt a broad range of benefits in evaluating regional transmission projects, as shown in Table 8.

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191 MISO, *Multi Value Project Portfolio: Results and Analyses*, January 10, 2012. Available at: https://www.misoenergy.org/Library/Repository/Study/Candidate%20MVP%20Analysis/MVP%20Portfolio%20Analysis%20Full%20Report.pdf.

Table 8
Transmission Benefits Considered in Non-RTO Regional Planning Processes

Non-RTO Planning Organization	Benefits Considered in Regional Planning
WECC	• Avoided local transmission project costs • Production cost savings • Reduced generation capital costs
ColumbiaGrid	• Avoided local transmission project costs
NTTG	• Avoided local transmission project costs • Reduced energy losses • Reduced reserve costs
WestConnect	• Avoided local transmission project costs • Production cost savings • Reserve sharing benefits
SERTP	• Avoided local transmission project costs
NCTPC	• Avoided local transmission project costs
Florida Sponsors	• Avoided local transmission project costs

Source: Chang, Judy W., Johannes P. Pfeifenberger, and J. Michael Hagerty, A WIRES Report on the Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments, July 2013.

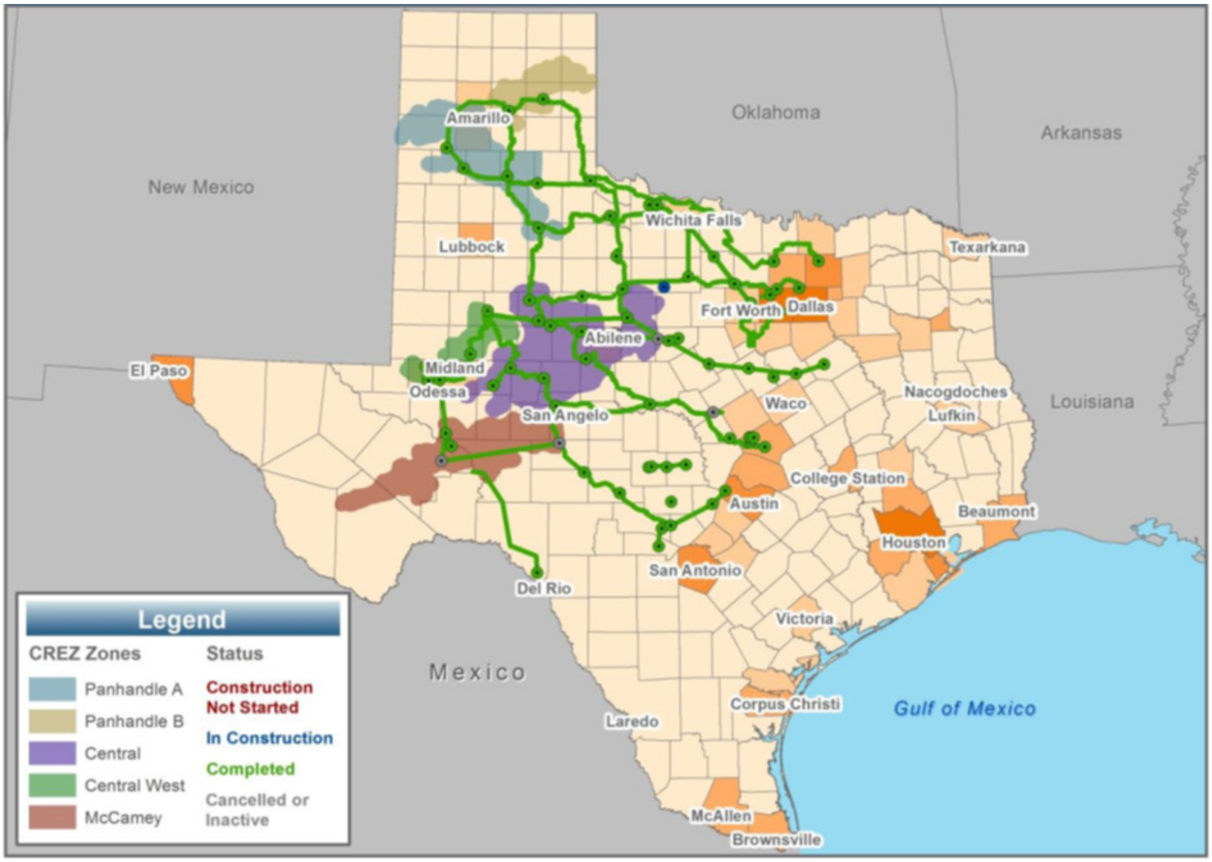
c. Meeting Public Policy Goals

A more recent addition to transmission planning is the consideration of the transmission facilities required for meeting public policies, such as those that promote the use of renewable energy through state RPS mandates. Transmission planning for the growing renewable generation capacity varies significantly across the U.S.

In Texas, the CREZ transmission planning process, mandated by the state legislature and overseen by the Public Utility Commission of Texas, has resulted in $6.9 billion of investment to build 3,600 miles of new transmission line for supporting 18.5 GW of wind capacity, as shown in Figure 45.[192] Texas, and specifically ERCOT, is unique as the wind resources and load exist within the same state and planning authority.

[192] RS&H, CREZ Progress Report No. 16 (July Update), Competitive Renewable Energy Zone Program Oversight, prepared for Public Utility Commission of Texas, July 2014. Available at http://www.texascrezprojects.com/page2960323.aspx.

Figure 45
Competitive Renewable Energy Zone Projects in Texas



Source: RS&H, CREZ Progress Report No. 16 (July Update), Competitive Renewable Energy Zone Program Oversight, prepared for Public Utility Commission of Texas, July 2014.

MISO evaluated the ability to meet the RPS goals within its territory in its Regional Generation Outlet Study (RGOS) in 2010.[193] The study led to transmission plans being incorporated into their MVP portfolio that are projected to reduce the cost of meeting RPS mandates by $1.3–2.5 billion by enabling access to higher quality wind resources than would otherwise be available.[194]

SPP has integrated renewable requirements into its analysis and has also studied scenarios in which a significant amount of renewable energy is exported from its region. As discussed in the previous section, all SPP lines are justified based on a broad range of economic benefits, although

[193] MISO, *Regional Generation Outlet Study* (RGOS), November 10, 2010, available at https://www.misoenergy.org/Library/Repository/Study/RGOS/Regional%20Generation%20Outlet%20Study.pdf.

[194] MISO, *Multi Value Project Portfolio: Results and Analyses*, January 10, 2012. Available at: https://www.misoenergy.org/Library/Repository/Study/Candidate%20MVP%20Analysis/MVP%20Portfolio%20Analysis%20Full%20Report.pdf..

both the ITP10 and ITP20 identify "primarily policy" transmission lines based on whether wind farms are expected to be curtailed in excess of 3% of their output.[195]

California analyzes transmission needs for meeting its 33% RPS in 2020 in its annual transmission planning study. One of the most significant transmission lines identified for meeting the RPS is the 256 mile Tehachapi Renewable Transmission Project, which is projected to increase access to renewable capacity by 4,500 MW.[196] Several segments of the project are already in service with the full project expected to be in service by 2016. The most recent CAISO Transmission Plan 2013–2014 approved two additional transmission projects for supporting renewable goals, as shown in Figure 46. In total, 18 transmission projects are in various stages of development to meet the California public policy goals.[197]

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195 SPP Engineering, 2012 Integrated Transmission Plan 10-Year Assessment Report, January 31, 2012. Available at: http://www.spp.org/publications/20120131%202012%20ITP10%20Report.pdf. The analysis has resulted so far in a single line, Gentleman-Cherry County-Holt County 345 kV, being identified as a "primarily policy project." Further evaluation of this project (known as the "R-Plan") led SPP to reclassify the line such that it is no longer considered a policy line. See page 9 of SPP Board of Directors/Members Committee Meeting Minutes for July 29, 2014 at http://www.spp.org/publications/BOCMC%20Minutes%20072914%20-%20Final%20-Corrected.pdf.

196 *Southern California Edison Company's (U 338-E) 2013 Preliminary Annual 33% Report (Public Version)*, before the Public Utilities Commission of the State of California, in the matter of Order Instituting Rulemaking to Continue Implementation and Administration of California Renewables Portfolio Standard Program, Rulemaking 11-05-005, filed May 5, 2011, available at http://www3.sce.com/sscc/law/dis/dbattach5e.nsf/0/094309ED6F7C810188257AE2000A6E34/$FILE/R1105005+RPS+-+SCE+2011+Preliminary+Annual+33+Percent+RPS+Compliance+Report_Public.pdf.

197 CAISO, 2013–2014 Transmission Plan, July 16, 2014. Available at http://www.caiso.com/planning/Pages/TransmissionPlanning/2013-2014TransmissionPlanningProcess.aspx.

Figure 46
Transmission Projects in California to Support 33% RPS

Transmission Facility	Online
Transmission Facilities Approved, Permitted and Under Construction	
Sunrise Powerlink (completed)	2012
Tehachapi Transmission Project	2015
Colorado River - Valley 500 kV line (completed)	2013
Eldorado – Ivanpah 230 kV line (completed)	2013
Carrizo Midway Reconductoring (completed)	2013
Additional Network Transmission Identified as Needed in ISO Interconnection Agreements but not Permitted	
Borden Gregg Reconductoring	2015
South of Contra Costa Reconductoring	2015
West of Devers Reconductoring	2019
Coolwater - Lugo 230 kV line	2018
Policy-Driven Transmission Elements Approved but not Permitted	
Mirage-Devers 230 kV reconductoring (Path 42)	2014
Imperial Valley Area Collector Station	2015
Sycamore – Penasquitos 230kV Line	2017
Lugo – Eldorado 500 kV Line Re-route	2015
Lugo – Eldorado series cap and terminal equipment upgrade	2016
Warnerville-Bellota 230 kV line reconductoring	2017
Wilson-Le Grand 115 kV line reconductoring	2020
Additional Policy-Driven Transmission Elements Recommend for Approval	
Suncrest 300 Mvar SVC	2017
Lugo-Mohave series capacitors	2016

Source: CAISO, 2013–2014 Transmission Plan, July 16, 2014, p. 11.

New England has yet to develop transmission projects specifically for accessing the highest quality regional wind resources, located in northern Maine, as the transmission capacity so far has been sufficient. However, meeting the increasing RPS requirements in southern New England with additional wind capacity in Maine (including wind farms that have recently signed long-term contracts with Massachusetts and Connecticut utilities through renewable procurement processes) is expected to require additional capacity to be built.[198] The primary challenge for planning new transmission for this purpose is developing a process for allocating the costs of the transmission to those who benefit from the line being built, which is currently being pursued through ISO-NE's compliance with FERC Order No. 1000, described in more detail in the next section.

PJM to-date has not built any lines specifically for meeting public policy goals, but has included in its 2013 RTEP analysis a review of state-by-state RPS mandates and scenarios for meeting the existing mandates within its territory. In that analysis, PJM found that a significant build out will be necessary and notes "additional transmission not only solves reliability criteria violations to meet RPS energy requirements but also yields economic benefits," including lower energy production costs, congestion costs, and load payments.[199]

Planning transmission on a regional and interregional scale remains a relatively new process with significant challenges in identifying which facilities to build and the appropriate cost allocation method for paying for the lines. Many of these issues were the driving force behind the regulations included in FERC Order No. 1000.

3. Key Challenges to Transmission Planning

While transmission investment is currently at historic levels and changes in transmission planning processes continue to evolve, many challenges still exist to building a reliable and efficient transmission network that will also enable public policy objectives. As seen in the previous section, a patchwork of planning processes are used across the U.S. to identify new transmission investments with most occurring at the local and regional levels with the primary goal of maintaining reliability. A few regions have begun to consider additional values over a wider geographical footprint, but identifying lines that cross multiple utilities and states can be difficult unless there is a clear reliability issue to resolve. Even when there is agreement that a new line is necessary, further efforts to identify the cost allocation methodology can result in the lines not being considered or justified through the existing processes.

In addition to identifying need, new transmission lines face several additional hurdles as they must receive the required permits from state and local regulatory agencies (in some jurisdictions referred to as a Certificate of Public Convenience and Need, or CPCN[200]) as well as

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198 Connecticut Department of Energy & Environmental Protection, 2014 Integrated Resources Plan for Connecticut, Appendix D: Renewable Energy, March 17, 2015, pp. D-26–D-27. Available at: http://www.ct.gov/deep/cwp/view.asp?a=4405&q=486946&deepNav_GID=2121%20

199 PJM, 2013 PJM Regional Transmission Expansion Plan Report, February 28, 2014, Book 1, p. 16. Available at: http://www.pjm.com/documents/reports/rtep-documents/2013-rtep.aspx.

200 For example see the New York State Department of Public Service description. http://www3.dps.ny.gov/W/PSCWeb.nsf/All/C78F4BE884AA2FA885257687006F3964?OpenDocument

environmental permits through federal, state, and local agencies. The selection of the location and route for transmission facilities, known as siting, is often a significant challenge to building new lines as developers must complete all required public outreach and/or hearings where they often face backlash from local communities, which can take significant time and resources to resolve.

In this section, we first review the requirements for transmission planning under FERC Order No. 1000 and discuss its impact on transmission planning processes, cost allocation, and the right of first refusal for incumbent utilities to build new lines as well as the continuing challenges in these areas. We then discuss challenges within the permitting and siting processes, which are primarily state-level requirements.

a. New Requirements under FERC Order No. 1000

FERC Order No. 1000 reforms the requirements for FERC-jurisdictional planning authorities in regards to transmission planning, cost allocation, and the standing of non-incumbent transmission developers. Order No. 1000 built on previous efforts through Order No. 890 and corrected deficiencies with respect to the previously existing transmission planning processes and cost allocation methods.[201] Three years later, FERC is still in the process of reviewing and approving different portions of the regulations for the planning authorities under its jurisdiction, especially the filings associated with interregional planning and cost allocation. There have been legal challenges to Order No. 1000 but the order was upheld by the DC Circuit Court of Appeals in August 2014.[202]

The new requirements under Order No. 1000 include the following:

- All public utility transmission providers are required to participate in a regional planning process that produces a regional transmission plan, to consider transmission needs by public policy requirements in both local and regional planning, and to participate in inter-regional planning to determine if more efficient or cost-effective solutions are available.
- FERC introduced specific requirements for cost allocation of transmission lines developed through regional planning processes, including a requirement that regional planning processes must establish cost allocation methods for new transmission facilities developed through regional planning efforts. In addition, neighboring planning regions must have a common cost allocation method for any

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201 FERC, Facts, Order No. 1000 Final Rule on Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, Docket No. RM10-23-000, July 21, 2011. Available at: http://www.ferc.gov/media/news-releases/2011/2011-3/07-21-11-E-6-factsheet.pdf; FERC, Fact Sheet, Order No. 890 Final Rule on Preventing Undue Discrimination and Preference in Transmission Service, Docket Nos. RM05-25-000 and RM05-17-000. Available at: https://www.ferc.gov/industries/electric/indus-act/oatt-reform/order-890/fact-sheet.pdf.

202 *South Carolina Public Service Authority v. FERC*, Nos. 12-1232 *et al.* (D.C. Cir., Aug. 15, 2014) Available at: http://www.ferc.gov/media/statements-speeches/lafleur/2014/08-15-14-lafleur.pdf

new interregional transmission projects. FERC allows for participant-funding of new transmission, but this approach cannot be used for cost allocation of transmission projects identified through regional or interregional planning.

- Finally, to promote competition for building new transmission projects, transmission providers no longer have a right of first refusal (ROFR) for transmission facilities that are selected to be built through regional planning efforts for purposes of regional cost allocation. The removal of the ROFR does not apply to facilities selected outside of regional planning, to upgrades to existing transmission facilities of which incumbent utilities remain the primary developers, or any state-jurisdictional ROFR provisions. The rule allows, but does not require, the use of competitive bidding to solicit projects or project developers.

Compliance with the regional and interregional requirements in Order 1000 has been staged with local and regional transmission planning processes and initial regional cost allocation filings required to be submitted in October 2012; initial filings concerning interregional transmission coordination process and cost allocation were required to be submitted by July 2013.[203]

Compliance with the regional requirements under FERC Order No. 1000 are nearly achieved, although several issues still remain unresolved. NYISO, for example, submitted in September 2014 a revision to its public policy approach. FERC is in the process of responding to the interregional compliance filings. The impacts of revisions to tariffs however will only be known once the rules are put into effect and transmission lines are identified (or not) through the new processes.

b. Regional Planning and Cost Allocation

Regional planning processes have been in place prior to Order 1000 in both RTO and non-RTO regions, with many created in response to Order 890.[204] The majority of existing regional planning entities maintained their current structure and planning processes to comply with Order 1000, but usually with some modifications. Other regions have grown to incorporate new members for meeting Order 1000 requirements, such as the Southeast Regional Transmission

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203 See FERC, Summary of Compliance Filing Requirements, updated September 3, 2013, online at http://www.ferc.gov/industries/electric/indus-act/trans-plan/comp-filing.asp. Some entities received an extension for their regional filings to 2013.

204 For an overview of regional planning and cost allocation processes, future issues, and the relative scope of Order 1000, see Pfeifenberger, Johannes, Transmission Investment Trends and Planning Challenges, presented at EEI Transmission and Wholesale Markets School, Madison, WI, August 8, 2012, available at http://www.brattle.com/system/publications/pdfs/000/004/432/original/Transmission_Investment_Trends_and_Planning_Challenges_Pfeifenberger_Aug_8_2012_EEI.pdf

Planning (SERTP).[205] FERC rejected the regional transmission planning entity proposed by Duke Energy Corp subsidiaries Duke Energy Carolinas LLC and Carolina Power and Light Company, who requested FERC to recognize their North Carolina Transmission Planning Collaborative (NCTPC) as its own transmission planning region. Instead, they will be joining SERTP.[206] Utilities in Florida, South Carolina, and New York have been recognized as their own planning regions by FERC when their territory is wide enough and their current process can be adapted to fulfill FERC Order No. 1000 requirements. The Florida Reliability Coordinating Council, Inc., (FRCC), for example, covers three investor-owned public utilities and two large municipal utilities and has updated its annual transmission planning process (a roll up of local plans) to include a biennial transmission plan that identifies potential regional transmission projects.[207]

Changes in the regional planning processes of entities that existed prior to Order 1000 have also occurred. For example, PJM in its 2013 RTEP released a new framework for developing its annual RTEP that considers Baseline Reliability Upgrades, Market Efficiency Upgrades, and State Public Policy Upgrades, which come together to form the Multi-Driver Upgrades, as outlined in Figure 47.[208] While the multi-driver approach was not submitted as part of PJM's Order 1000 compliance, the process furthers many of the goals set out by Order 1000.[209] However even if implemented, exactly how many transmission projects will actually be considered "multi-driver" projects and be approved through the PJM stakeholder process will still need to be seen.

[205] 145 FERC ¶ 61,252, *Order on Rehearing, Clarification, and Compliance,* issued December 19, 2013, available at http://www.ferc.gov/whats-new/comm-meet/2013/121913/E-2.pdf.

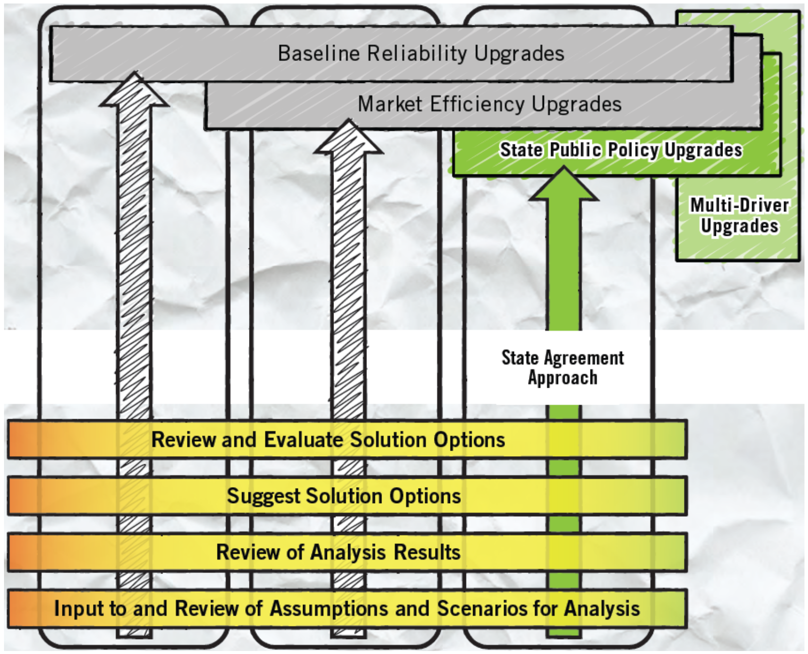
[206] *Id.* FERC ruled that while NCTPC fulfilled local transmission planning requirements, it could not approve a planning region where the two providers report to the same senior management, board of directors, and shareholders. Duke had planned on including Alcoa Power Generating Inc., however their transmission infrastructure was too limited to make the NCTPC's scope large enough to meet regional planning requirements.

[207] 148 FERC ¶ 61,172, O*rder on Rehearing and Compliance*, issued September 5, 2014, available at http://www.ferc.gov/CalendarFiles/20140905134738-ER13-80-001.pdf.

[208] PJM, 2013 PJM Regional Transmission Expansion Plan Report, February 28, 2014, Book 1. Available at: http://www.pjm.com/documents/reports/rtep-documents/2013-rtep.aspx.

[209] Letter from Craig Glazer and Pauline Foley (PJM) to Hon. Kimberly D. Bose (Secretary, FERC) re PJM Interconnection, L.L.C., Docket No. ER14-2864-000, dated September 12, 2014 regarding filing proposed revisions to Schedule 6 of the Operating Agreement to add new provisions allowing PJM to plan for and include multiple driver projects in its regional transmission expansion plan, available at http://www.pjm.com/~/media/documents/ferc/2014-filings/20140912-er14-2864-000.ashx. FERC conditionally accepted the changes to incorporate Multi-Driver Upgrades into its tariff on February 20, 2015, requesting that PJM provide further details on the criteria by which they will select Multi-Driver projects. 150 FERC ¶ 61,117, *Order Accepting Tariff Revisions Subject to Conditions*, Issued February 20, 2015.

Figure 47
PJM Proposed New Regional Transmission Expansion Process



Source: PJM, 2014 PJM RTEP Input Assumptions, June 30 2014 ("2014 PJM RTEP Input Assumptions"). Available at: http://www.pjm.com/~/media/documents/reports/rtep-plan-documents/2014-input-assumptions-white-paper.ashx.

Although Order 1000 requires all FERC-jurisdictional entities to participate in regional planning, it is unclear to what extent the changes will lead to improved planning and identification of projects that would not have been built previously.

A primary barrier to regional transmission development continues to be how the cost of new transmission projects will be recovered within the region. Cost allocation became a significant challenge for planning regional transmission lines following the decision by the Seventh Circuit District Court in 2009 to overturn FERC's approval of PJM's cost allocation method. The ruling found that the PJM tariff, which shared all costs of "regional" transmission lines on a load-ratio share basis (known as a "postage stamp" approach), did not sufficiently demonstrate that entities assigned costs for the project would receive commensurate benefits.[210] As part of its ruling, the Seventh Circuit District Court remanded the rate design issue to the FERC.[211] The ruling had

[210] The court found that requiring ratepayers to pay for projects for which they receive no benefit to be unjustified. In the ruling the seventh court noted that "nothing in FERC's opinions in this case enables even the roughest ballpark estimates on these benefits." See Illinois Commerce Commission, *et al.*, v. FERC, 576 F.3d 470 (7th Cir. 2009) at 476. The ruling recommended that in the future cost allocation processes allocate costs in a manner that is "roughly commensurate" to benefits.

[211] In March 2012 the FERC reaffirmed the "postage-stamp" methodology, arguing that it is not possible to quantify the benefits of new projects, and that high-voltage transmission lines should be treated as benefiting the entire system. (138 FERC ¶ 61,230, *Order on Remand*, issued March 30, 2012, available at http://www.ferc.gov/EventCalendar/Files/20120330144130-EL05-121-006.pdf) On June 25, 2014 the Seventh Circuit District Court again remanded to the FERC the PJM cost allocation methodology.

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nation-wide implications and was influential in FERC issuing Order 1000 and continues to be a major obstacle for both regional and interregional processes.

PJM's Order No. 1000 filing explains its cost allocation approach for "regional lines," which PJM defines as all "double-circuit facilities planned to operate at voltages of at least 345 kV, but less than 500 kV, as well as all facilities planned to operate at 500 kV or above."[212] The PJM approach filed in response to Order 1000, which was developed and filed separately by PJM's transmission owners, now allocates 50% of costs to beneficiaries and 50% through a postage stamp approach.[213] Under this approach, PJM will identify beneficiaries in different ways, depending on whether the project is reliability-based or economic based. For reliability-based transmission projects, beneficiaries will be determined based on a power flow distribution factor (DFAX) metric and for economic projects, beneficiaries will be based on a metric that measures the zonal changes in load energy payments that result from adding the line.[214] Both approaches are simplified processes to estimate the deemed distribution of benefits, which do not necessarily consider actual benefits received and do not address a potentially wide range of other benefits provided by transmission investments. The cost of all other reliability- and economically-driven transmission projects will be assigned 100% based on these beneficiaries metrics and not include any postage-stamp portion that is shared equally across the entire region.

A similar development has also occurred in MISO. In response to Order 1000 and the PJM court order, MISO has reduced the amount of regional cost sharing for reliability projects by eliminating its prior approach that shared 20% of project costs across the region. This cost allocation approach results in 100% of all costs from the load of the transmission zone in which the lines are built without consideration for a wider range of benefits.[215]

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(*Illinois Commerce Commission, et al., v. FERC*, Nos. 13-1674, *et al.*, (7th Cir. June 25, 2014), available at http://www.ferc.gov/legal/court-cases/opinions/2014/13-1674.pdf.

212 PJM, *Compliance Filing Of PJM Interconnection, L.L.C.*, before the Federal Energy Regulatory Commission, in the matter of Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, Docket No. RM10-23-000, October 25, 2012, p. 77, available at http://www.pjm.com/~/media/documents/ferc/2012-filings/20121025-er13-198-000.ashx.

213 Letter from Paul D. Napoli (PSE&G), and Donald Kaplan and Kenneth G. Jaffe (Alston & Bird) to Hon. Kimberly D. Bose (Secretary, FERC) re PJM Open Access Transmission Tariff Revisions to Modify Cost Allocation for PJM Required Transmission Enhancements Docket No. ER13-90-00, October 11, 2012 ("PJM 2012 Tariff Revision Filing"), available at http://www.pjm.com/~/media/documents/ferc/2012-filings/20121011-er13-90-000.ashx.

214 Distribution factors measure the use of an upgrade by each MW of a zone's load served by a MW of PJM generation, as determined by power flow analysis. As explained in the PJM Transmission Owner filing, "The proposal uses a 'Solution-Based' DFAX analysis to evaluate the relative use that load in each Zone and withdrawals by merchant transmission facilities are projected to make of the new facility." See PJM 2012 Tariff Revision Filing.

215 Letter from Matthew R. Dorsett (MISO), Daniel M. Malabonga and Bryan M. Likins (Venable), and Wendy N. Reed and Matthew J. Binnett (Wright & Talisman) to Kimberly D. Bose (Secretary, FERC) re *Midwest Independent Transmission System Operator, Inc.'s and MISO Transmission Owners'*

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Non-RTO regions have also struggled with identifying cost allocation methods that meet Order 1000 requirements. For example, SERTP initially filed an approach to determining the benefits of new regional projects simply by calculating the cost of avoided local projects. This method assigns the costs of longer, regional lines to the regions where smaller, local reliability lines were avoided because of these projects.[216] FERC ultimately rejected this approach, ruling that relying solely on avoided-costs defined benefits too narrowly and was only appropriate for reliability lines whereas SERTP had proposed using this method for reliability, economic, and public policy lines. In a later filing, SERTP expanded the types of benefits it quantifies in its cost allocation methodology to include the benefits provided by a new line through reduced energy losses.[217] While FERC has rejected avoided cost as an appropriate method for cost allocation at the regional level, many interregional groups have proposed this approach, noting that a wide range of benefits are considered under regional planning and will not need to be repeated at the interregional level.[218]

Other non-RTO planning entities target specific methods for each line. For example, WestConnect's approved methodology identifies different benefits for each type of line in order to determine cost allocation: regional reliability-driven lines are allocated based on the costs of avoided local transmission projects; the cost of regional economically-driven lines is allocated based on estimates of production cost savings and reduced reserve sharing requirement benefits; and public policy-driven lines are allocated based on the capacity of policy-supported renewable generation projects that are enabled.[219]

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Compliance Filing for Order No. 1000, Regarding Regional Planning and Cost Allocation of Transmission Projects with Regional Benefits (Part 1 of 2), Docket No. ER13-187-000, October 25, 2012, available at https://www.misoenergy.org/Library/Repository/Tariff/FERC%20Filings/2012-10-25%20Docket%20No.%20ER13-187-000.pdf.

216 144 FERC ¶ 61,054, *Order on Compliance Filings*, issued July 18, 2013, available at http://www.ferc.gov/whats-new/comm-meet/2013/071813/E-1.pdf.

217 Letter from Jennifer Key (Steptoe & Johnson for Duke Energy), Jennifer Keisling (LG&E and KU Energy), Brian E. Chisling (Simpson Thacher & Bartlett for Ohio Valley Electric), and Andrew W. Tunnell (Balch & Bingham for SCS) to Hon. Kimberly D. Bose (Secretary, FERC) re *The Southeastern Regional Transmission Planning Process, Order No. 1000 Regional Compliance Filing, Submitted Under Protest as Discussed Herein*, FERC Docket Nos. ER13-83, -897, -913, -908, January 14, 2014, available at https://www.vsb.org/sections/ad/pdf/dukeenergycarolinasfiling.pdf.

218 Letter from Matthew R. Dorsett (MISO) and Daniel M. Malabonga (Veneble) to Hon. Kimberly D. Bose (Secretary, FERC) re Midcontinent Independent System Operator, Inc.'s and MISO Transmission Owners' Compliance Filing for Order No. 1000, Regarding Interregional Transmission Project Coordination and Cost Allocation with the Southestern Regional Transmission Planning Region, Docket No. ER13-1923-000, dated July 10, 2013.

219 Letter from William M. Dudley (Xcel Energy) to Hon. Kimberly D. Bose (Secretary, FERC) re Public Service Company of Colorado, Southwestern Public Service Company, Xcel Energy Operating Companies FERC Electric Tariff, Second Revised Volume No. 1, Docket No. ER13-75, Order No. 1000 OATT Compliance Filing, dated October 11, 2012.

Additional challenges that have come up in the Order 1000 filings include identifying alternative regulated transmission solutions for regional cost allocation and the role of states in identifying the need for public policy-driven transmission lines.[220] The recent NYISO's compliance filing is an example of the role of state agencies in identifying public policy lines.[221] Under the new Public Policy Transmission Planning Process, the New York State Public Service Commission (NYPSC) and New York State Department of Public Service (NYDPS) are both given roles in identifying transmission needs driven by public policy requirements. NYISO then requests proposed solutions be submitted, reviews the viability and sufficiency of proposed solutions, evaluates which will be the most cost effective, and presents their selections in a Public Policy Transmission Planning Report.[222]

c. Interregional Planning and Cost Allocation

Interregional transmission lines have traditionally been built by neighboring utilities and regions to take advantage of resource availability and to provide for reserve sharing during emergency situations. Order No. 1000 strives to expand the role of interregional transmission planning to increase the overall efficiency of the interconnected regional systems and to provide opportunities for remotely-located renewable development to access larger markets.

The planning regions' Order No. 1000 compliance filings for interregional planning currently remain under review by FERC after being submitted in July 2013. The filings show that the cost allocation issues that exist within a region generally become more difficult at the interregional level. The challenge at the interregional level is to integrate the different approaches chosen by each region for its own regional planning. These approaches may not be acceptable or compatible with the chosen approach of a neighboring region.

Several RTOs also argued in their submissions to FERC that their existing interregional planning processes already comply with Order No. 1000. For example, MISO and PJM explained that they have a Joint Operating Agreement (JOA) which guides their review of interregional lines.[223] As a

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220 For more on alternative transmission solutions, see Frayer, Julia and Eva Wang, *A Wires Report on Market Resource Alternatives: An Examination of New Technologies in the Electric Transmission Planning Process*, October 2014, available at http://wiresgroup.com/docs/reports/WIRES%20Final%20MRA%20Report_September%202014.pdf

221 Letter from Joy A. Zimberlin (NYISO) to Hon. Kimberly D. Bose (Secretary, FERC) re New York Independent System Operator, Inc. and New York Transmission Owners, Compliance Filing, Docket No. ER13-102-110, -002, -004, dated September 15, 2014, all filing documents available for download at http://www.nyiso.com/public/markets_operations/documents/tariffviewer/index.jsp.

222 NYISO System and Resource Planning, *Reliability Planning Process Manual*, Manual 26, Version 2.1, September 26, 2014, available at http://www.nyiso.com/public/webdocs/markets_operations/documents/Manuals_and_Guides/Manuals/Planning/rpp_mnl.pdf.

223 PJM Interconnection, L.L.C., *Submission of Interregional Transmission Coordination Procedures Between PJM Interconnection, L.L.C. and Midcontinent Independent System Operator, Inc.,* Docket

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result, MISO and PJM only made minor adjustments to their JOA to comply with Order No. 1000. MISO and PJM state that with those few alterations, such as enhancing the roles of its existing planning committees—the Joint RTO Planning Committee (JRPC) and the Inter-regional Planning Stakeholder Advisory Committee—the JOA will comply with the FERC Order No. 1000 interregional planning requirements.

On cost allocation however, MISO and PJM reached an impasse on whether the existing JOA cost allocation method for reliability projects is sufficient. PJM believes that the existing allocation approach is sufficient, which is based on each region's DFAX contribution to congestion on the constraint that is upgraded by the new line.[224] MISO believes such projects should fall under regional cost allocation methods. In its filing, MISO proposed removing the existing flow-based cost allocation mechanisms for Cross Border Baseline Reliability Projects (CBBRPs). In June, MISO had removed regional cost allocation for Baseline Reliability Projects (BRPs) and believes CBBRPs cannot be eligible for interregional cost allocation either. MISO instead proposes tie-lines between PJM and MISO be CBBRPS whose ownership and responsibilities for upgrades are shared by the transmission owners.[225] It is not clear that either the existing or the proposed MISO-PJM process will adequately identify beneficial interregional transmission projects. MISO and PJM have had JOA provisions for Cross-Border Market Efficiency Projects (CBMEP) in place since 2008 and to date, no cross-border projects have been approved for cost allocation under the existing provisions.[226] The JOA seeks to identify transmission projects that benefit end-use customers of both RTOs in terms of lower transmission congestion costs and lower costs of producing power.

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No. ER13-1944, July 10, 2013, available at http://www.pjm.com/~/media/documents/ferc/2013-filings/20130710-er13-1944-000.ashx.

224 Letter from Kenneth G. Jaffe (Alston & Bird) and Donald A. Kaplan (K&L Gates) to Hon. Kimberly D. Bose (Secretary, FERC) re PJM Transmission Owners Filing Regarding Compliance with Interregional Cost Allocation Requirements of Order No. 1000, Docket Nos. RM10-23 and ER13-1924-000; and PJM, Submission, Docket No. ER13-1944, *op. cit*.

225 Letter from Matthew R. Dorsett (MISO), Daniel M. Malabonga and Jason R. Wool (Venable), and Brooksany Barrowes (Baker Botts) to Kimberly D. Bose (Secretary, FERC) re Midwest Independent Transmission System Operator, Inc.'s and MISO Transmission Owners' Compliance Filing for Order No. 1000, Regarding Interregional Transmission Project Coordination and Cost Allocation with PJM Interconnection, L.L.C., Docket No. ER13-1943-000, July 10, 2013 ("MISO Order 1000 Filing, July 10, 2013"), available at http://sustainableferc.org/wp-content/uploads/2013/09/Library/1-Major-FERC-Rulemakings/1.5.%20Order%201000%20-%20Planning%20and%20Cost%20Allocation/1.5.4.%20Regional%20Compliance%20Proceedings/1.5.4.0.%20Interregional%20Filings%20%26%20Comments/1.5.4.0.1.%20Eastern%20Interconnection/ER13-1943/2013.07.10%20-%20MISO%20Inc.pdf

226 Prepared Direct Testimony of Jennifer Curran on Behalf of Midcontinent Independent System Operator, Inc. and MISO Transmission Owners, Docket ER13-1943, July 10, 2013, filed as Table D of MISO Order 1000 Filing, July 10, 2013.

Market participants have complained that the methods used for interregional transmission planning by the two RTOs create significant barriers and gaps with the end result that few if any interregional transmission projects would be able to qualify and simultaneously pass the two RTOs' individual and joint screening tests.[227] Under the interregional methodology, projects would need to pass the MISO's Market Efficiency Project criteria (including a benefit to cost ratio of 1.25 based on Production Cost savings over the first 20 project years and voltage greater than 345 kV) and PJM's criteria (a benefit to cost ratio of 1.25 based on 70% Production Cost Savings + 30% Net Load Payment Savings over first 15 years of project life). Finally, they would also have to meet interregional criteria that includes project costs greater than $20 million, and addresses one or more constraints for which at least one dispatchable generator in the adjacent market has a Generation to Load Distribution Factor (GLDF) of 5% or greater with respect to serving load in that adjacent market.[228]

In initial rounds of reviews using the amended JOA to identify interregional efficiency projects, very few projects have been identified. Out of more than 85 transmission projects proposed to resolve congestion across the regions' borders only three projects met the 1.25 benefit to cost ratio. From the recent round of reviews, the MISO-PJM Inter-Regional Planning Stakeholder Advisory Committee (IPSAC) has questioned whether $20 million threshold will result in larger, less economic projects and if the benefit to cost threshold should be necessary for project approval.[229]

Similarly, both MISO and SERTP filed that there were unable to agree with SPP on the appropriate scope of interregional planning efforts. With MISO, SPP notes the approach MISO proposed "unreasonably limits" the identification of interregional projects that could more efficiently address transmission needs than separate regional projects.[230] SERTP highlights that they were able to come to agreement with the four other regions in which they share a seam, but could not do so with SPP who wants to allow for projects to be proposed at the interregional

[227] "MISO / PJM Joint and Common Market (JCM) NIPSCO Request for Action," March 21, 2014, available at http://www.pjm.com/~/media/committees-groups/stakeholder-meetings/pjm-miso-joint-common/20140321/20140321-item-07-nipsco-request.ashx.

[228] MISO Order 1000 Filing, July 10, 2013.

[229] MISO/PJM, Joint MISO-PJM Planning Study, presented at MISO-PJM IPSAC 15th Meeting, May 16, 2014, available at http://www.pjm.com/~/media/committees-groups/stakeholder-meetings/ipsac/20140516-joa/20140516-item-01-joint-miso-pjm-planning-study.ashx.

[230] Compliance Filing of Southwest Power Pool, Inc., before the Federal Energy Regulatory Commission, in the matter of Southwest Power Pool, Docket No. ER13-1937, July 10, 2013 ("SPP Compliance Filing 2013"), available at http://sustainableferc.org/wp-content/uploads/2013/09/Library/1-Major-FERC-Rulemakings/1.5.%20Order%201000%20-%20Planning%20and%20Cost%20Allocation/1.5.4.%20Regional%20Compliance%20Proceedings/1.5.4.0.%20Interregional%20Filings%20%26%20Comments/1.5.4.0.1.%20Eastern%20Interconnection/ER13-1937/2013.07.10%20-%20Southwest%20Power%20Pool%20Inc.pdf.

level that resolve transmission needs considered by SPP but that go beyond those addressed in SERTP's regional planning process.[231]

This experience illustrates that the planning regions prefer to apply a more narrow scope to interregional planning than that of their own regional planning effort. These challenges often lead to interregional regional transmission planning frameworks that reflect the "least common denominator" across neighboring regions. This least common denominator approach creates a significant barrier to interregional transmission planning and could be avoided if regions were willing to evaluate every interregional projects based on the same set of criteria they use for regional transmission planning.[232]

d. ROFR Revisions and Competitive Solicitations

The increase in identification of transmission projects that cross planning, utility, and state/regional boundaries has led to changes in the processes for selecting the transmission developers that will build the new facilities. Both incumbent transmission companies and non-incumbent transmission developers have become more active in recent years in identifying and building new transmission facilities. There are a number of distinct business models in which non-incumbents have pursued entry into the transmission development market, as shown in Table 9.

[231] *Id.*

[232] For more discussion of interregional planning see WIRES Report, pp. 23–24 and Pfeifenberger, J.P., J.W. Chang, and D. Hou, "Bridging the Seams: Interregional Planning under FERC Order 1000," *Public Utility Fortnightly*, November 2012, online at http://www.fortnightly.com/fortnightly/2012/11/bridging-seams?authkey=080439e41374360d63a049ea975e1a3eacd45cb808190fb8121e4f74ab0138b7.

Table 9
Non-Incumbent Transmission Developer Business Models

	Strategy	Examples
1	Transmission partnerships with incumbents	ITC and AEP JVs in SPP
2	Public-private partnerships	MATL, Transbay Cable, Path15
3	Independent transmission company (new build)	Anbaric, TransElect, AWC
4	Merchant transmission	Zephyr, SunZia, Neptune
5	Transmission bundled with renewables	NextEra, RES Americas
6	Transmission subsidiaries	AEP, Transource, DATC
7	Spin-off of transmission into quasi-ITC	ATC
8	Independent incumbent transmission (acquisitions)	ITC
9	Passive investment	Private Equity
10	Buy/invest in developer	Cleanline, Path 15

Source: Pfeifenberger, Johannes, Judy Chang, Matthew Davis, and Mariko Geronimo, Contrasting Competitively-Bid Transmission Investments in the U.S. and Abroad, presented at UBS Conference Call, May 13, 2014.

Merchant transmission development has recently also led to the development of new lines, which largely occurs outside the transmission planning processes described above and, for high voltage direct current (HVDC) lines, requires signing capacity agreements with generators for reaching new markets or off-takers for accessing generation in another region.[233]

As a result of Order 1000's requirements for removal of ROFR provisions, several regions have begun to implement competitive solicitation processes for either: (1) identifying and selecting innovative solutions to a need identified through their planning processes or (2) selecting which developer will build a line identified through the planning process. The competitive solicitations in PJM, ISO-NE, and NYISO reflect the first approach, while the solicitations in CAISO, ERCOT, MISO and SPP primarily use the latter approach.[234]

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233 Merchant transmission lines proposed within a region must undergo analyses to determine whether the new facilities will lead to issues on other transmission facilities, similar to the analysis of whether network upgrades are required during generator interconnection studies. For example, ISO-NE approved the addition of Northern Pass subject to the upgrades included in its approval letter. Letter from Stephen J. Rourke (NYISO) to Dennis Carberry (Northeast Utilities) re Revision 1—Northern Pass Transmission Project Proposed Plan Applications (PPAs), NU-13-T20, NU-13-T21, NU-13-T22, NU-13-T23 NU-13-T24, NU-13-T26, and NU-13-X03, dated January 9, 2014. Available at: http://www.iso-ne.com/trans/pp_tca/isone_app_approvals/prop_plan/2013/dec/a_npt_i_3_9_rev1.pdf

234 Pfeifenberger, Johannes, Judy Chang, Matthew Davis, and Mariko Geronimo, Contrasting Competitively-Bid Transmission Investments in the U.S. and Abroad, presented at UBS Conference Call, May 13, 2014. Available at: http://www.brattle.com/system/publications/pdfs/000/005/068/original/UBS_-_Brattle_Competitive_Transmission_Presentation_051314.pdf

While there is more experience internationally in competitive solicitations for transmission, as in Brazil where all projects since 1999 have been auctioned through competitive solicitations, several regions have already begun implementing competitive processes, including CAISO and PJM.[235]

PJM identified a transmission issue in southern New Jersey, referred to as the "Artificial Island," and requested that developers submit potential solutions for improving stability and operational performance and eliminating potential planning criteria violations.[236] In response, a total of twenty-six proposals were submitted by seven project sponsors with costs ranging from $100 million to $1.5 billion.[237] PJM selected seven projects and completed a final evaluation of four similar projects based on several factors, including an independent cost analysis, time to completion, existing land rights, and construction complexity.[238] The process for selecting the Artificial Island solution is on-going.[239]

PJM also considers transmission proposals for Market Efficiency Projects for overcoming projected congestion, which must pass a benefit/cost test. In 2013, PJM reviewed 17 proposals and found 5 to be no longer needed, 9 to not pass the benefit/cost threshold of 1.25, and the other 3 all relieved congestion at the same transformer. Of the three, the lowest cost solution of installing a second transformer and reconductoring the transmission line was selected in place of the other two that required new lines to be installed.[240]

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235 *Id.*, p. 6.

236 PJM, *PJM RTEP—Artificial Island Area Proposal Window: Problem Statement & Requirements Document*, Version 14.0, revised May 16, 2013, available at http://www.pjm.com/~/media/planning/rtep-dev/expan-plan-process/ferc-order-1000/rtep-proposal-windows/redacted-artificial-island-problem-statement.ashx

237 PJM, *Artificial Island Proposal Window*, Version 2, PJM Special TEAC, Artificial Island Review, May 19, 2014. Available at http://www.pjm.com/~/media/committees-groups/committees/teac/20140519/20140519-artificial-island-review.ashx Additional information on the proposals can be found at PJM, Artificial Island Proposal Window, online at http://www.pjm.com/planning/rtep-development/expansion-plan-process/ferc-order-1000/rtep-proposal-windows/closed-artificial-island-proposals.aspx

238 PJM, *Artificial Island Proposal Window*, PJM TEAC, Artificial Island Recommendation, June 16, 2014, available at http://www.pjm.com/~/media/committees-groups/committees/teac/20140616/20140616-teac-artificial-island-recommendation.ashx

239 Since the announcement of the initial project recommendation, the four bidders were required to re-submit their bids to PJM to undergo a new evaluation and selection process that will be overseen by a FERC-appointed Administrative Law Judge. For more information see Letter from Pauline Foley (PJM) to Hon. Curtis L. Wagner (FERC) re Status Report—Artificial Island Solicitation, Appointment of Facilitor, Docket No. MD14-1, available at http://www.pjm.com/~/media/planning/rtep-dev/expan-plan-process/ferc-order-1000/rtep-proposal-windows/pjm-letter-to-chief-judge-wagner-regarding-artificial-island.ashx

240 PJM, Market Efficiency RTEP Proposal Window, PJM TEAC presentation, January 9, 2014. Available at: http://www.pjm.com/~/media/committees-groups/committees/teac/20140109/20140109-teac-010914-market-efficiency.ashx

CAISO identified its first three projects for competitive solicitations in its 2012–2013 Transmission Plan.[241] Following the first solicitation for the Imperial Valley Project in which only two bids were received, CAISO revised its approach by identifying "key selection criteria" prior to the start of the process. During the two subsequent solicitations (*i.e.*, Gates-Gregg and Sycamore-Penasquitos), CAISO identified the key selection criteria as experience acquiring rights-of-way, capability to develop, build, operate, and maintain the facilities, project schedule, and cost containment provisions. While the projects attracted interest beyond the incumbent utilities, all three projects have been awarded to either the incumbent or a joint venture that includes the incumbent utility.[242]

These processes are expected to continue to develop and be improved as additional experience is gained, as seen in the CAISO process. While there appear to be significant benefits from requesting solutions at the earlier stages of development, the PJM Artificial Island project is showing that doing so increases the complexity and time required for the process. In addition, the CAISO example suggests that there appears to be a significant advantage in having a local partner due to the local system knowledge, crew availability, and access to existing facilities or right of ways.[243]

e. Permitting and Siting Challenges

Permitting and siting transmission facilities is primarily a state level function as the location of facilities and the costs borne by ratepayers fall under the jurisdiction of state public utility commissions and similar organizations, even if the wholesale-level costs are approved by FERC. The requirements for each jurisdiction across the U.S. vary quite significantly, making it difficult to summarize a standard process or categorize states into different groupings.[244]

A whitepaper on siting transmission in the western states summarizes the range of state siting processes in the following way:

> Some states have a centralized siting authority that has jurisdiction over a proposed project regardless of whether the developer is a regulated public utility, a municipality, or an independent operator. Others have regulatory authority that is

241 CAISO, *2012–2013 Transmission Plan*, March 20, 2013. Available at: http://www.caiso.com/Documents/BoardApproved2012-2013TransmissionPlan.pdf

242 Pfeifenberger, Johannes, Judy Chang, Matthew Davis, and Mariko Geronimo, Competition in Transmission Planning and Development: Current Status and International Experience, presented at EUCI—Transmission Policy: A National Summit, Washington, DC, January 31, 2014. Available at http://www.brattle.com/system/publications/pdfs/000/004/977/original/Competition_in_Transmission_Planning_and_Development.pdf

243 *Id.*

244 For a summary of state transmission siting requirements, see EEI, State Generation & Transmission Siting Directory: Agencies, Contacts, and Regulations, October 2013, online at: http://www.eei.org/issuesandpolicy/transmission/Documents/State_Generation_Transmission_Siting_Directory.pdf

fragmented, depending on whether the proponent of a project is subject to state regulatory commission jurisdiction. Some states require the siting authority to consider regional needs for transmission development in connection with a proposal, while others only require that state and local interests be considered. Some state siting authorities not only preempt but actually make decisions for the local governments affected by a proposed project, while other states reluctantly provide for a mechanism to appeal onerous local government requirements to the siting authority or another entity.[245]

Generally, state permitting processes require:

- Environmental impact analyses to be conducted either through the state level agency or oftentimes, primarily in the western states, through federal agencies that oversee federal public lands with environmental mitigation plans established for the construction phase;
- Public hearing and/or outreach, which can include town meetings, discussions with landowners, and opportunities for interveners to present their concerns to the state regulatory body;
- Right of way approval through meetings with landowners, environmental agencies, and regulatory agencies; and
- Certificates of Public Convenience and Need (CPCN), which require formal application submissions of the justifications for the projects, details on project route and design, and a cost estimate.

Several states provide relatively clear roadmaps for navigating the regulatory process, although the clarity of the information often can be deceiving as more complex processes may require several submissions of an application before it is considered complete. Well-structured processes, though long, may provide increased certainty in the time and costs of permitting relative to jurisdictions with limited formal processes. For example, the Ohio Review Board provides a flowchart of regulatory processes that must be completed before receiving a certificate for siting a new transmission facility, as shown in Figure 48.

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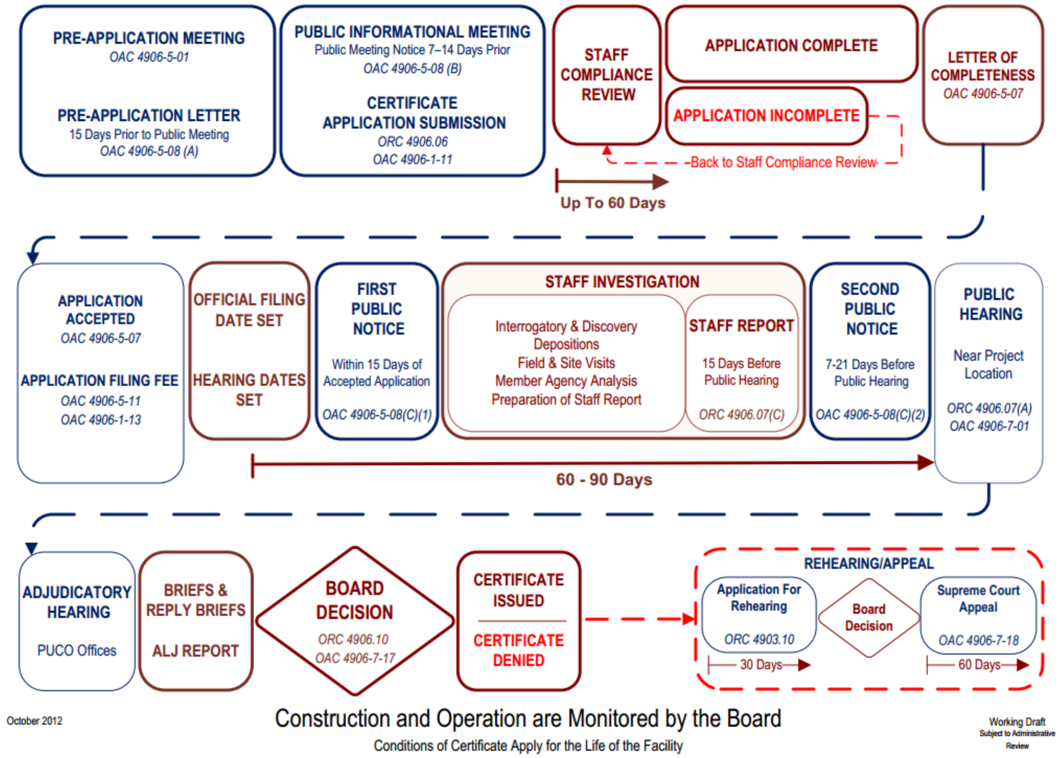
245 Hotkamp, James and Mark Davidson, *Transmission Siting in the Western United States:* Overview *and Recommendations*, prepared as information to the Western Interstate Energy Board, August 2009. Available at: http://www.hollandhart.com/articles/Transmission_Siting_White_Paper_Final.pdf.

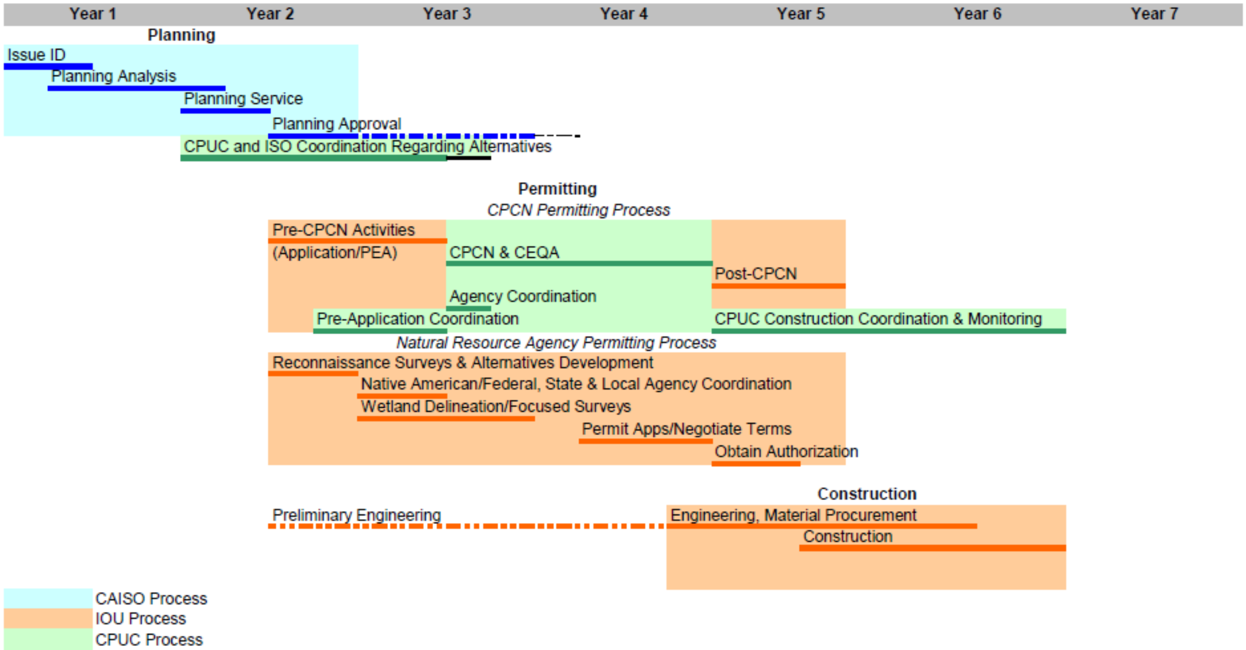
Figure 48
Ohio Power Siting Process Flowchart



Source: Ohio Power Siting Process Flowchart, Working Draft, October 2012. Available at http://www.opsb.ohio.gov/emplibrary/files/OPSB/flowchart.pdf

As noted above, obtaining a permit is just one process for building a new transmission facility. The California Public Utility Commission provides a summary of the entire process from planning through construction for building a transmission lines in California, as shown in Figure 49.

Figure 49
California Transmission Development Process Flowchart



Source: Strauss, Robert L., Processes for Planning and Permitting Electric Transmission Projects in California, prepared for CPUC, October 2011. CPUC notes this is a "best case scenario timeline."

For aiding future transmission investment in its state, the Wyoming Infrastructure Authority developed a detailed summary of the state and federal permitting processes expected to be required for building new transmission in the state.[246]

At the federal level, nine agencies signed a 2009 memorandum of understanding (MOU) to closely coordinate transmission project permitting through a Rapid Response Team on Transmission (RRTT) and improve overall quality and timeliness of electric transmission infrastructure permitting, review, and consultation by the Federal government.[247]

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246 Navigating the environmental permitting processes alone can be challenging. To facilitate new transmission facilities being built in their state, the Wyoming Infrastructure Authority developed a detailed summary of the state and federal permitting processes expected to be required. Tetra Tech, *Guide to Permitting Wind Energy Projects in Wyoming*, prepared for the Wyoming Renewable Energy Coordination Committee, July 2012. Available at http://wyia.org/wp-content/uploads/2012/10/guide-_wind-permitting-in-wy1.pdf

247 Participating Agencies include: the Department of Agriculture, the Department of Commerce, the Department of Defense, the Department of Energy, the Department of Interior, the Environmental Protection Agency, the Federal Electric Regulatory Commission, the Advisory Council on Historic Preservation, and the White House Council on Environmental Quality. See The White House, Council on Environmental Quality, Interagency Rapid Response Team for Transmission, online at http://www.whitehouse.gov/administration/eop/ceq/initiatives/interagency-rapid-response-team-for-transmission

Jurisdictional and geographic differences can have significant impacts on projects costs across all phases of a transmission project as well as potentially requiring major adjustments to the project schedule. Environmental impacts are often closely monitored throughout the construction period and can often lead to changes in the processes for building a transmission line once the plan has been established and even required complete re-designs of the line and route. Delays in the permitting process can alter scheduled usage of major equipment, such as cranes and helicopters, and lead to rushed procurement of materials and labor. In some instances, the season in which lines are built may be impacted by migratory patterns or firmness of the soil due to heavy rains around the construction sites. The type of land that is being traversed can also have an impact on costs as it may require different techniques for setting the foundation of transmission structures, challenges for accessing the site, increased level of environmental stringency (*e.g.*, crossing wetlands), or challenges in gaining public approval due to "not in my backyard" concerns.[248]

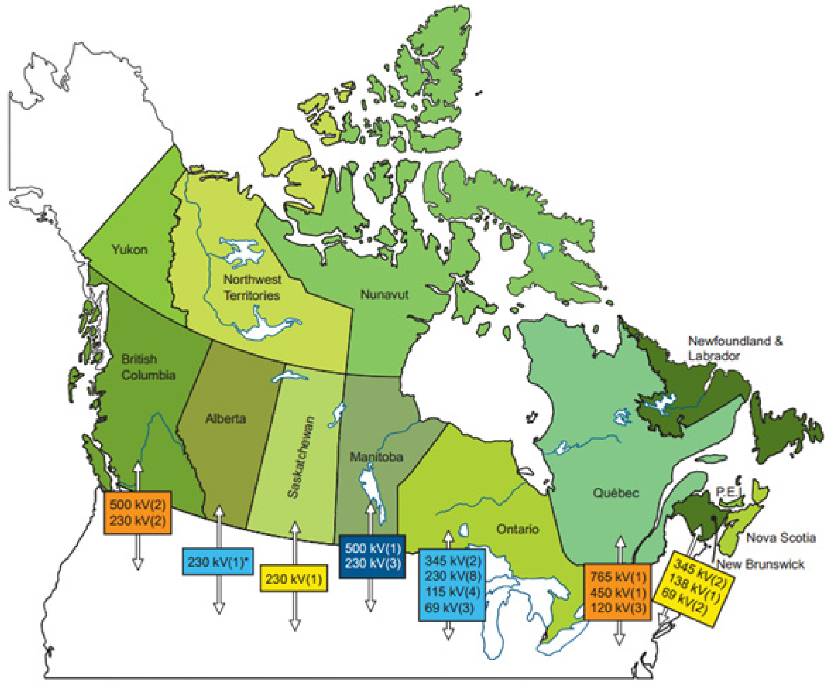
E. CROSS BORDER TRANSMISSION

In addition to the issues outlined in this chapter for transmission projects within the U.S., the international nature of the transmission network is an important aspect of the system that can provide additional opportunities and challenges for building the future power system. The U.S. has significant interties with Canada, forming a North American transmission network, as shown in Figure 50, as several of the provinces in Canada operate synchronously with networks in the U.S.[249]

[248] SWCA Environmental Consultants, Environmental Mitigation Costs Study – Final Report for the Western Electricity Coordination Council, Submitted to Environmental Data Task Force, November 8, 2013, p. 23. Available at: https://www.wecc.biz/Reliability/2013_Mitigation_Cost_Study_FinalReport_EDTF.pdf

[249] The Quebec Interconnection, while asynchronous to the Eastern Interconnection that spans both the U.S. and Canada, has significant interties with the northeastern market, historically supplying hydroelectric generation from HydroQuebec facilities.

Figure 50
Major Canada-U.S. Transmission Interconnections



Source: Canadian Electricity Association, Canada's Electricity Industry, n.d., p. 25. Available at http://www.electricity.ca/media/Electricity101/Electricity101.pdf.

In contrast, the U.S. has limited interties with the Mexican transmission network, as shown in Figure 51. Two synchronous 230 kV AC lines connect CAISO with the Baja California North system that are used to serve load in southern California and two 115 kV AC lines connect into El Paso that are generally used for emergency conditions.[250] Several DC lines in Texas can provide bi-directional flow between ERCOT and Mexico's Comisión Federal de Electricidad (CFE) power grid.[251]

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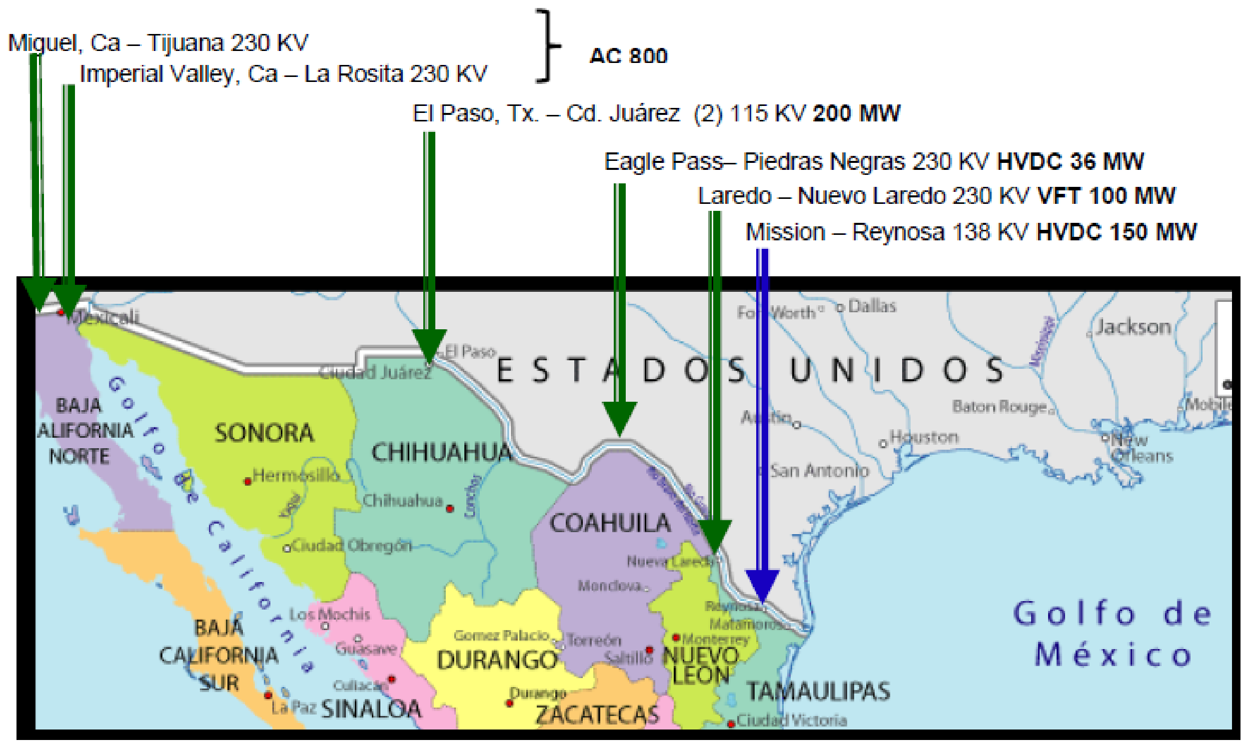
250 Arizona-Mexico Commission Energy Committee Bi-National Electricity Transmission Task Force, *Bi-National Electricity Transmission Opportunities for Arizona and Sonora*, White Paper, Arizona-Mexico Commission Summary Plenary Sessions, Scottsdale, AZ, June 14, 2013. Available at: http://www.azenergy.gov/doclib/6-14-13_Bi-NatlTF-Eng-WEB.pdf

251 For more information on the 300 MW HVDC tie between Sharyland Utilities and the CFE power grid, see Sharyland Utilities, Transmission, online at http://www.sharyland.com/transmission/.

Figure 51
Mexico-U.S. Transmission Interconnections

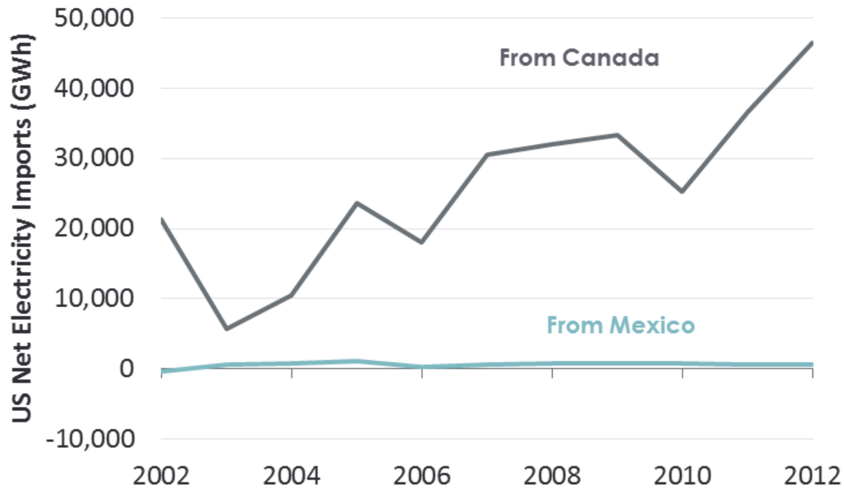


Source: Arizona-Mexico Commission Energy Committee Bi-National Electricity Transmission Task Force, Bi-National Electricity Transmission Opportunities for Arizona and Sonora, White Paper, Arizona-Mexico Commission Summary Plenary Sessions, Scottsdale, AZ, June 14, 2013.

Figure 52 shows recent trends in net electricity imports from Canada and Mexico and that in both cases the U.S. is a net importer with net imports from Canada growing significantly since the early 2000s.[252] The trends for net imports from Canada represent both an increase in imports and a decrease in exports. The net imports from Mexico remain relatively limited over the past decade with no clear trends.

[252] EIA, Table 2.13. Electric Power Industry-U.S. Electricity Imports from and Electricity Exports to Canada and Mexico, 2002–2012.

Figure 52
U.S. Net Electricity Imports from Canada and Mexico

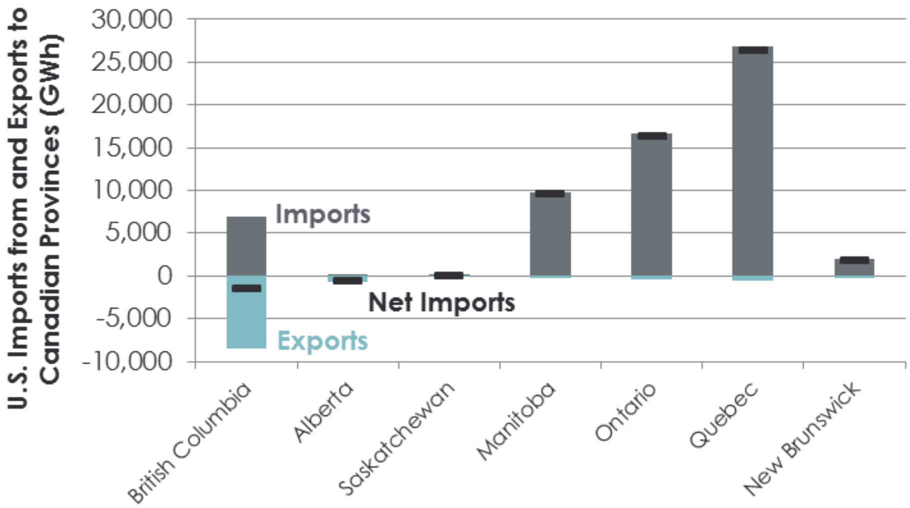


Source: EIA, Table 2.13. Electric Power Industry-U.S. Electricity Imports from and Electricity Exports to Canada and Mexico, 2002–2012. Available at http://www.eia.gov/electricity/annual/html/epa_02_13.html.

The nature of power flows between the U.S. and Canada differs significantly by province. The Canadian provinces of Quebec, Ontario, and Manitoba have large hydro generation resources that they sell into the U.S. markets and represent the majority of the total imports into the U.S., as shown in Figure 53. Alberta and Saskatchewan have limited interties with the U.S. and they have not had excess generation to sell into the U.S.[253]

[253] Canadian Electricity Association, Canada's Electricity Industry, n.d., p. 24. Available at http://www.electricity.ca/media/Electricity101/Electricity101.pdf

Figure 53
U.S. Imports from and Exports to Canadian Provinces



Source: Canadian Electricity Association, Canada's Electricity Industry, n.d., p. 24. Available at http://www.electricity.ca/media/Electricity101/Electricity101.pdf.

Although its hydro generation capacity is lower than in the eastern provinces (generating less than a third as much power as Quebec, for example), British Columbia (BC) plays a more significant role in power markets in the western part of the U.S. through BC Hydro's marketing arm, Powerex, which has been authorized by the FERC to sell at market-based-rates in the U.S. Powerex generally sells power into the U.S. seasonally, with excess hydro generation exported to the U.S. primarily in the summer during periods of high prices and power imported from the U.S. in low price seasons, which leads to an annual net export of power to BC from the U.S, as shown in Figure 53. There are many benefits (*e.g.*, flood control on the Columbia and balancing renewable energy output) to U.S. and Canada coordinated operation of hydro generation resources, which is based on the long-standing Columbia River Treaty that is set to expire in the next decade.[254] The reservoir capacity of the BC hydro generation facilities that allows them to take advantage of seasonal differences in electricity prices can also respond rapidly to changes in renewable generation output, which will become more valuable as California gets closer to meeting its 33% RPS set for 2020.

1. Transmission Expansion with Canada

In contrast to recent trends in U.S. energy policy, the Canadian Electricity Association (CEA) includes in its vision for the future Canadian systems the goals of increasing interdependence both amongst its provinces and the U.S.[255] Cross-border trade can provide a range of benefits to both systems, as identified by CEA in a recent paper:

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[254] For more information on the future of the Columbia River Treaty, see Columbia River Treaty 2014/2024 Review, online at http://www.crt2014-2024review.gov/

[255] Canadian Electricity Association, Vision 2050, online at http://powerforthefuture.ca/vision-2050/

> By interconnecting into each other's networks at over 35 points, the two countries benefit from numerous advantages: a higher level of reliable service for customers through enhanced system stability; efficiencies in system operation; efficiencies in fuel management; opportunities to use power from nearby markets to address local contingencies; and expanded access to low-emitting and competitively-priced resources.[256]

Individual utilities in Canada have also set goals to increase transfer capability with the U.S. markets. For the U.S., accessing Canadian hydro generation can provide low cost, zero carbon generation to markets that are increasingly looking to de-carbonize. However, there may be significant pushback from developing additional transmission capacity to access the energy, as it may adversely impact revenues from energy and capacity markets for existing domestic generators and potentially blunt incentives for additional domestic investment in generation.

In the case of the Northern Pass transmission line from Quebec into southern New Hampshire, the proposed line has been developed as a "merchant" project and not through the ISO-NE transmission planning process.[257] The project is currently undergoing environmental and state permitting and if built will be expected to provide access to 1,200 MW of hydro generation from HydroQuebec.[258]

The addition of new hydroelectric generation facilities in Canada is leading to further consideration of additional transmission into the U.S. HydroQuebec is currently in the process of developing 2,500 MW of new hydro resources, which are projected to come on-line through 2020, and are looking to add an additional 3,000 MW beyond 2020. Two HVDC transmission lines into New England (the New England Clean Power Link) and New York City (Champlain Hudson Power Express) have been proposed for supplying a mix of wind and hydro power into those markets.

In addition, Nalcor is developing 3,000 MW of new hydro resources through its Lower Churchill Project in Labrador in two phases.[259] While plans for transmission lines have not yet been

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256 Canadian Electricity Association, *The Integrated Electric Grid: Maximizing Benefits in an Evolving Energy Landscape*, 2013, available at http://www.electricity.ca/media/pdfs/CanadaUS/CEA_US%20Policy%20Paper_EN.pdf.

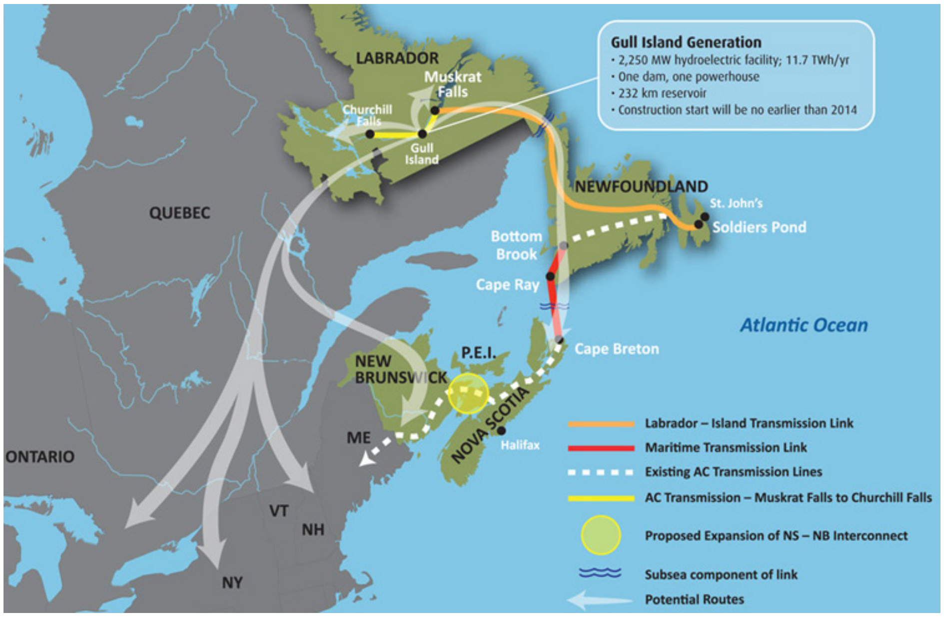
257 For interconnecting with the ISO-NE system, the new line did have to go through ISO-NE's process to demonstrate its impact on the reliability on the existing bulk power network, similar to interconnection studies for new generation capacity. Through the process, ISO-NE determined that the project required additional transmission infrastructure improvements, or "network upgrades," to mitigate its adverse impact on the bulk power system. Only after the proponents agreed to make the required system improvements did ISO-NE approve the project.

258 The line will be "participant funded," such that it will not be required to be justified through the ISO-NE planning processes or be subject to its cost allocation to ratepayers. See The Northern Pass, online at http://northernpass.us/index.htm.

259 The 824 MW Muskrat Falls facility is currently under construction with an expected online date in 2018, while the 2,250 MW Gull Island is in early stages of development.

developed, the illustration of options for exporting the Gull Island generation is indicative of the routes that are likely to be pursued, as shown in Figure 54.

Figure 54
Potential Transmission Plans for Gull Island Generation



Source: Nalcor Energy, Lower Churchill Project, online at http://www.nalcorenergy.com/Lower-Churchill-Project.asp

Manitoba Hydro has studied opportunities for utilizing its hydro generation facilities to provide renewable balancing services into MISO and recently has proposed two alternative lines for increasing capacity into Minnesota by 750 MW. The MISO study of the proposed lines found that the benefits of adding each line (including production cost savings, load cost savings, reserve cost savings, and wind curtailment reduction) exceeded the costs by greater than a 2-to-1 margin. However, as the production cost savings alone are not high enough to justify the line as a Market Efficiency Project within MISO's transmission planning process, the project would not receive cost recovery under the existing tariff.[260] The line is instead recommended to be considered in future Multi-Value Project studies.[261]

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260 "The purpose of the recently initiated Market Efficiency Planning Study (MEPS) is to evaluate transmission needs and identify solutions to promote market efficiency from a holistic regional view, through a comprehensive, structured approach." MISO, Market Efficiency Planning Study Report Draft, July 2013, p. 3. Available at: https://www.misoenergy.org/Library/Repository/Study/MTEP/2013%20Market%20Efficiency%20Planning%20Study%20Report%20Draft.pdf

261 Bakke, Jordan, Zheng Zhou, and Sumeet Mudgal, *Manitoba Hydro Wind Synergy Study: Final Report*, MISO, 2013.

2. Transmission Expansion with Mexico

While the amount of transmission between the U.S. and Mexico is currently limited, the reforms that are currently underway in Mexico are partly intended to address the lack of transmission investment within Mexico and may provide new opportunities. The reforms aim to develop a wholesale electricity market such that qualified traders will be able to buy and sell power on the market, including imports from the U.S. However, the reforms have included limited provisions for power import and export facilities thus far.

Additional linkages between the U.S. and Mexico could provide benefits to both countries. For example, due to cultural differences, the systems experience peak load during different hours that could provide opportunities for shared capacity resources. In addition, trade between the markets in each country could reduce the cost of electricity for ratepayers.

III. Distribution

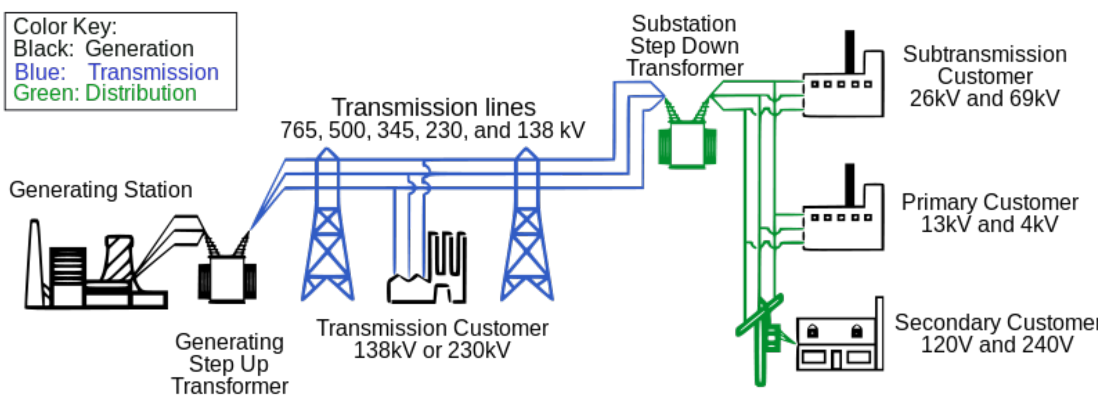
A. Physical Summary of the Distribution System

In this section, we provide an overview of the distribution system, including its current role, the cost of maintaining and expanding the system, and the implications of the evolving role that the distribution system will play in the utility of the future. Reliability at the distribution level, and threats to that reliability, will be discussed in the subsequent section.

1. Role: Connecting Transmission to Load

The traditional role of the distribution system has been the delivery of power from the transmission system to homes and businesses for final use. Thus the existing system was designed to serve a relatively simple role, in that the flow of power across lines is unidirectional, with limited control technology or information exchange required. Meters needed only to measure the total power consumed at each location over a period of time. The distribution system is depicted by the green parts of the diagram in Figure 55.

Figure 55
Traditional Structure of the Electric System



Source: DOE, Office of Electricity Delivery and Energy Reliability, Infrastructure Security and Energy Restoration (DOE/OE/ISER) *Large Power Transformers and the U.S. Electric Grid*, June 2012, p. 5.

However, various technological developments, including "Smart Grid"-based technologies, distributed generation, demand response, and the rise of plug-in EVs, increase both the value and the complexity of the distribution system. The spread of distributed generation means that the distribution network is now expected to accommodate an increasing level of two-way power flows. Distributed storage, whether in the form of plug-in EVs or other technologies, will pose similar requirements. Smart grid technologies (discussed in further detail below) require the incorporation of new communications networks and control systems into what is known as the advanced metering infrastructure (AMI). Thus, the technological role of the distribution grid is expanding beyond its traditional role in several dimensions, and may undergo more radical changes in the near future.

2. Efficiency of Distribution System

A central question in assessing the efficiency of the distribution system is the level of cost involved in maintaining and operating that system. Costs can be broken down into three categories: the carrying costs of the large capital investments made to build the system; operating costs, including labor and truck rolls;[262] and line losses.

a. Investment and Operation Costs

Limited information is available regarding the costs of maintaining and improving the nation's distribution system, either on a historical or a projected basis. However, the consensus is that significant investments are being made and need to continue to be made in order to meet the growing demands on the distribution system. EEI estimates that the industry has invested $275 billion (in 2012 dollars) in the nation's distribution system from 2000–2012, including $20.1 billion in 2012.[263]

Figure 56 below displays net investment, as well as operations and maintenance (O&M) expenses, recorded at the distribution level by utilities required to file FERC Form 1.[264] This is a somewhat crude measure, as not all utilities are required to file.

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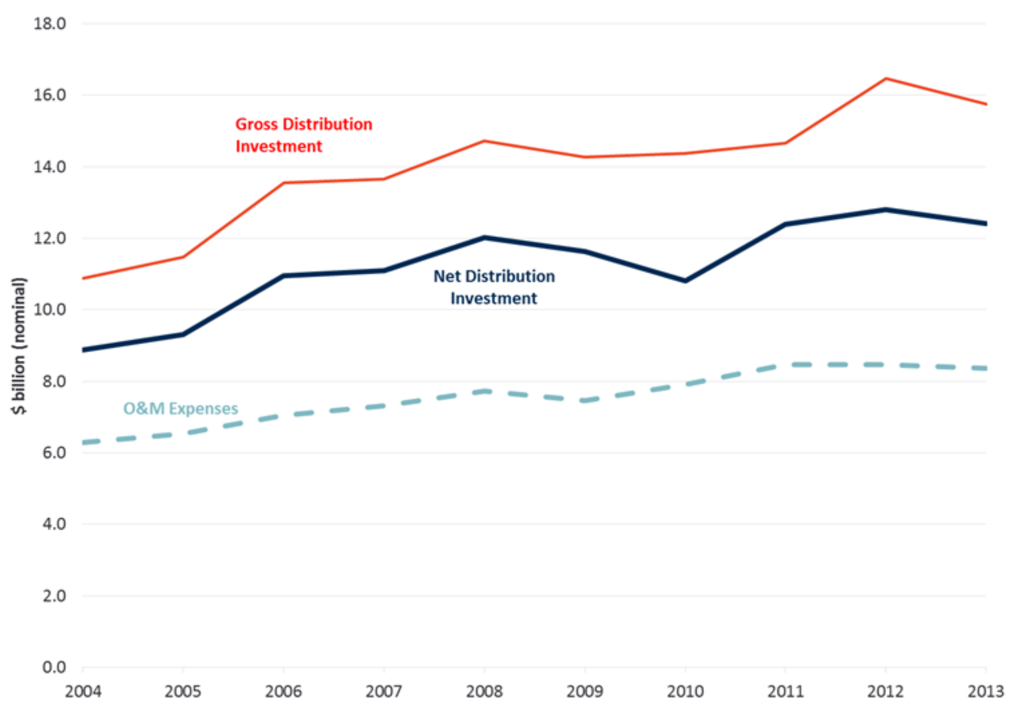
262 "Truck roll" is a term that refers to the dispatch of a truck to a location on the distribution system (often a customer site), for the purpose of either making some physical change to the system or addressing an outage.

263 Edison Electric Institute, "EEI Survey Shows Electric Power Industry Made Record Levels of Investment in Transmission and Distribution," December 18, 2013, online at http://www.eei.org/resourcesandmedia/newsroom/Pages/Press%20Releases/EEI%20Survey%20Shows%20Electric%20Power%20Industry%20Made%20Record%20Levels%20of%20Investment%20in%20Transmission%20and%20Distribution.aspx. The $275 million includes only investor-owned electric utilities and stand-alone transmission companies.

264 FERC Form 1 data can be obtained directly from FERC at http://www.ferc.gov/docs-filing/forms/form-1/viewer-instruct.asp or from data providers such as ABB, Inc, Velocity Suite.

Figure 56
Investor-Owned Utility Distribution Investment and O&M Costs, 2004–2013



Source and Notes: FERC Form 1 data, obtained via ABB. Net investment is calculated as the end-of-year balance of distribution plant assets minus the balance at the end of the previous year. Thus, in addition to new investment, it reflects depreciation and retirements. Gross investment is simply the sum of new additions to the distribution plant. There are 22 separate categories reflected in the O&M Expenses line above. The largest categories, by dollar amount, include maintenance and operations of overhead lines, underground lines, and station equipment; supervision & engineering; and meter expenses. Note that FERC Form 1 only needs to be filed by "major utilities," which reflects roughly 70–75% of nationwide electric customers and sales. One utility that only began reporting in 2010 is excluded so that the graph reflects a consistent sample. As of October 2014, a handful of companies had not filed their 2013 data, so the data points for 2013 are an estimate.

b. Line Losses

A key consideration in evaluating the performance of a distribution system is its efficiency, as measured by the share of power delivered to the system that ultimately is delivered to end users of electricity. In other words, to what extent is the distribution system able to avoid losses? However, most nation-wide data sources quantifying losses do not typically distinguish between transmission and distribution losses. For example, EIA estimates that the total combined transmission and distribution system has averaged 6% losses from 1990 to 2012.[265] Figure 57 below shows that losses, as a percentage of generation, have generally decreased over the past two decades.

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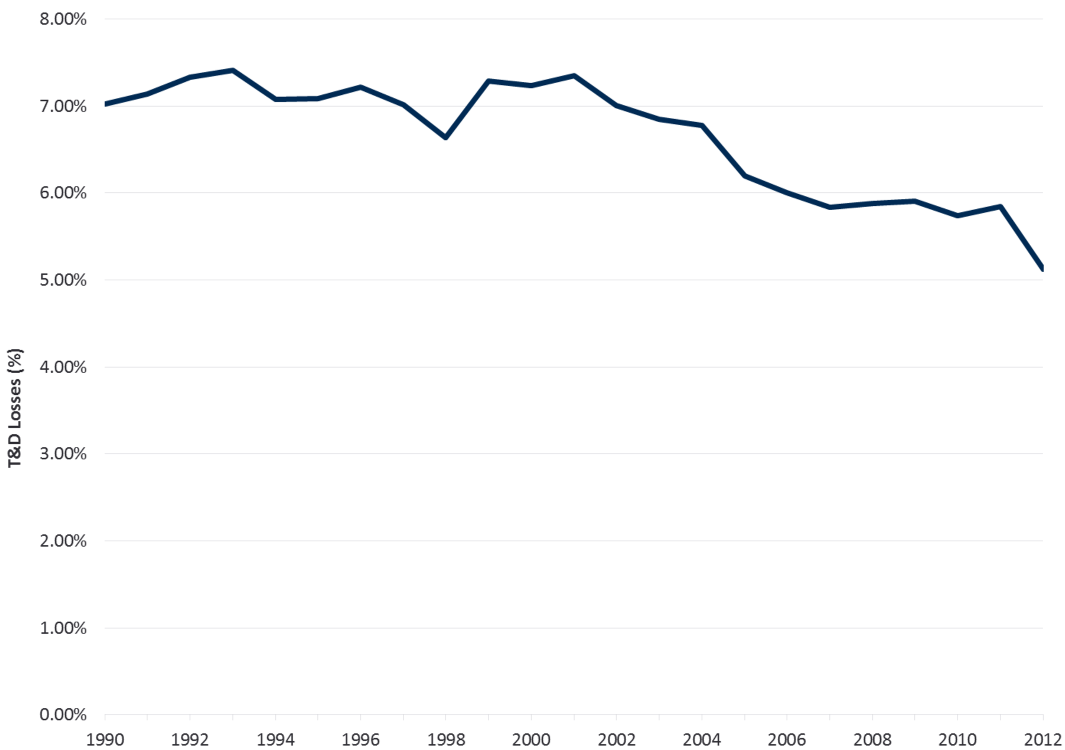
[265] U.S. Energy Information Administration, Frequently Asked Questions, How much electricity is lost in transmission and distribution in the United States?, online at http://www.eia.gov/tools/faqs/faq.cfm?id=105&t=3.

Figure 57
Transmission & Distribution Losses (%), 1990-2012



Source: EIA-923 data.

Distribution losses can be incurred at the substation transformer level, and on primary and secondary distribution lines. A 1989 study at one utility estimated both energy and demand losses by segment of the distribution system (substation, primary feeders, distribution transformer, secondary feeder, and service lines) and found that together these amounted to 3.9% of sales. Furthermore, they found that the combination of primary feeder and distribution transformer losses accounts for approximately two-thirds of all energy and demand losses on the distribution system.[266] Line losses are highly dependent on the electrical characteristics of the final few miles of the distribution system. For example, rural circuits typically have higher losses compared to urban and suburban feeders because circuits are longer.[267] DOE has developed standards for the energy efficiency of distribution transformers since 2007; new standards taking effect in 2016 are projected to save up to $12.9 billion in total costs to consumers over a 30-year period.[268]

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266 Grainger, J.J., and T.J. Kendrew, "Evaluation of Technical Losses on Electric Distribution Systems," CIRED 1989, 10th International Conference on Electricity Distribution, Brighton, May 8-12, 1989, available for purchase at http://ieeeexplore.com/xpl/login.jsp?tp=&arnumber=206129&url=http%3A%2F%2Fieeeexplore.com%2Fstamp%2Fstamp.jsp%3Ftp%3D%26arnumber%3D206129.

267 Short, Thomas Allen, *Electric Power Distribution Handbook, Second Edition.* CRC Press, 2014, p. 26.

268 U.S. Department of Energy, Building Technologies Office, Distribution Transformers, online at http://www1.eere.energy.gov/buildings/appliance_standards/product.aspx/productid/66. This reflects

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B. SYSTEM VULNERABILITIES AND ADVANCES IN SYSTEM RELIABILITY

Before discussing reliability performance, advances in reliability, and causes of vulnerabilities, a few definitions are useful. In the last few years, some in the electric industry have begun to distinguish between the reliability and the resiliency of the distribution system. One helpful way to think about the distinction is to add the qualifier "blue-sky" before the word reliability, which refers to the robustness of the system under normal day-to-day conditions. The Department of Energy has developed the definitions in Table 10 to clarify this distinction; other definitions have been used by other sources; the definitions in Table 10 will be used throughout the remainder of this section.

Table 10
Definitions of Reliability and Resiliency as Articulated by Department of Energy

Reliability	Resiliency
Sturdy and dependable, not prone to breakdowns from internal causes (*e.g.*, due to component failures)	The ability to withstand small to moderate disturbances without loss of service, to maintain minimum service during severe disturbances, and to quickly return to normal service after a disturbance.

Source: Department of Energy, Quadrennial Energy Review: Scope, Goals, Vision, Approach, Outreach, May 15, 2014. Available at:http://energy.gov/sites/prod/files/2014/06/f17/qer_public_deck_june_twothree.pdf.

This distinction is not universally used, and in some cases the lines between the two are blurred. Several investments that are made for the purpose of improving blue-sky reliability will also increase resiliency, and vice versa. Also, to the extent that customer interruption data is available, it generally does not differentiate between reliability and resiliency issues (or between transmission- and distribution-level causes). This section addresses both reliability and resiliency issues.

The DOE's Office of Electricity Delivery & Energy Reliability collects information on electric incidents and emergencies (OE-417).[269] These data provide some indication of the relative

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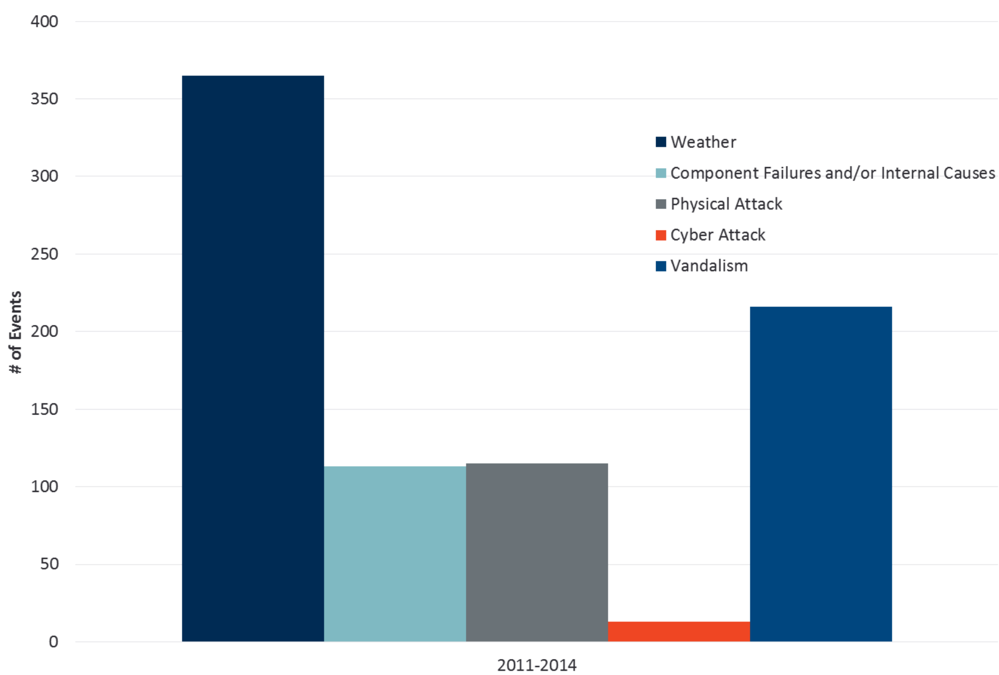
savings in 2011 dollars over the 2016-2045 period, net of installed costs; further details can be found in 10 CFR Part 431, Federal Register 78(75) at 23340 (Section I.C.), April 18, 2014, available at http://www.regulations.gov/#!documentDetail;D=EERE-2010-BT-STD-0048-0762.

269 The OE-417 data can be obtained at U.S. Department of Energy, Office of Electricity Delivery & Energy Reliability, Electric Disturbance Events (OE-417) Annual Summaries, online at https://www.oe.netl.doe.gov/OE417_annual_summary.aspx. The data include outage events but also other types of disturbances such as voltage reduction, load shedding, vandalism or sabotage, and public appeals to reduce load; the reporting requirements differ for different types of events, meaning that the events are not directly comparable. Furthermore, not all events include the number of customers affected. Finally, it is worth noting that disturbance events are reported at the distribution utility level, so a single event will be counted several times if multiple utilities are affected. For

Continued on next page

importance of different types of disturbances (weather-related, internal causes and component failures, physical attacks, and cyber-attacks). As Figure 58 and Figure 59 indicate, disturbances caused by internal component failures are less prevalent than disturbances due to external causes (in particular weather-related), both in terms of the number of events as well as their impacts.[270]

Figure 58
Electric Disturbance Events, 2011–August 2014



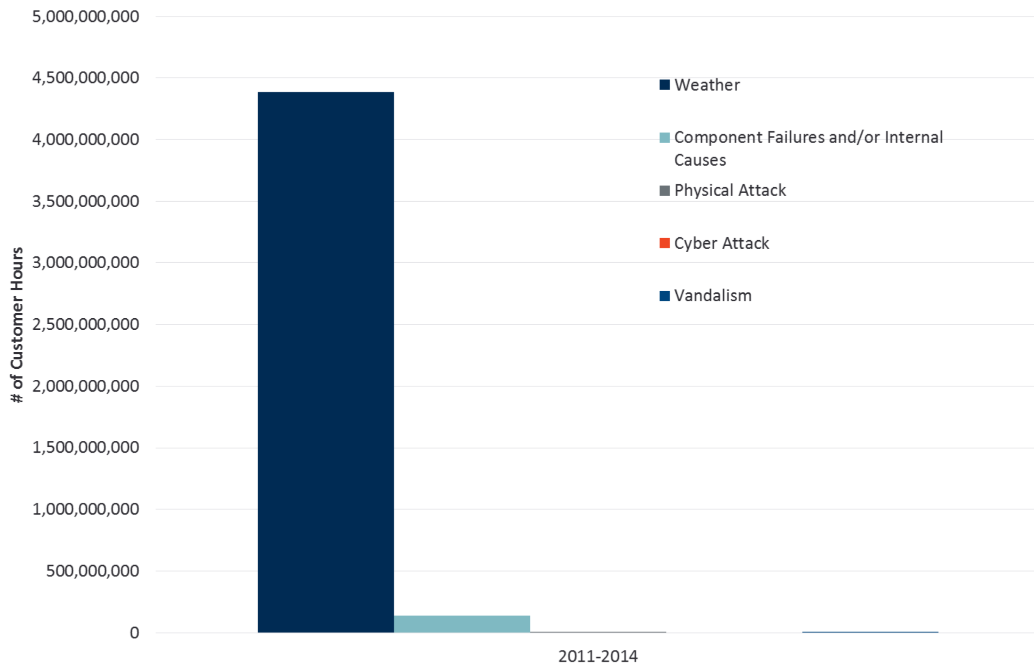
Source and Notes: Electric Disturbance Events (OE-417) database, Office of Electricity Delivery & Energy Reliability, Department of Energy, https://www.oe.netl.doe.gov/oe417.aspx. Events in the OE-417 database were categorized by The Brattle Group based on the text description provided in the "Event Type" field. See footnote 269 for a more complete description of this data and its limitations.

Continued from previous page

example, there are 21 entries for Hurricane Sandy, as utilities throughout the Northeast and Mid-Atlantic were affected. Figure 58 and Figure 59 do not attempt to correct for this "double-counting". It is important to note that many reported disturbances under the OE-417 Form do not lead to an actual customer outage, *i.e.* a blackout. Reporting is also done when a system operator makes a public call for voluntary load reductions, as is common for example by PJM. Here, a conscious choice was made to not build sufficient generation to cover all possible peak load situations, and instead rely on voluntary load reductions, including public appeals.

270 Electric Disturbance Events (OE-417) database, Office of Electricity Delivery & Energy Reliability, Department of Energy, https://www.oe.netl.doe.gov/oe417.aspx. Events in the OE-417 database were categorized by The Brattle Group based on the text description provided in the "Event Type" field. See footnote 236 for a more complete description of this data and its limitations.

Figure 59
Customer Hours Affected by Electric Disturbance Events, 2011–August 2014



Source and Notes: Electric Disturbance Events (OE-417) database, Office of Electricity Delivery & Energy Reliability, Department of Energy, https://www.oe.netl.doe.gov/oe417.aspx. Events in the OE-417 database were categorized by The Brattle Group based on the text description provided in the "Event Type" field. See footnote 269 for a more complete description of this data and its limitations.

1. Reliability Performance

Reliability data in the form of system average interruption metrics, such as SAIDI and SAIFI, are compiled internally by utilities, but are not consistently made public.[271] Within the data that are publicly available, understanding the origin of the interruptions, in particular whether interruptions originate at the bulk system level or the distribution system level, is even more challenging. There is general acceptance that interruptions originating on the distribution system account for the majority of customer interruptions, though detailed statistics on the distribution system's share are elusive.

Research on annual reliability metrics, not distinguishing distribution from bulk system initiation, from the past 10 years has shown that: (1) reported reliability decreased over the 2000–2009 period (although this decrease is smaller than routine year-to-year variations); (2) installation of an outage management system (OMS) is correlated with an increase in the reported duration of power interruptions, and (3) reliance on the voluntary industry standard for

[271] SAIDI stands for system average interruption duration index, which is calculated as the sum of all customer interruption durations divided by the total number of customers served. It is usually measured over the course of a year. The system average interruption frequency index, or SAIFI, is similar, but instead focuses on the frequency of events instead of the duration.

calculating reliability metrics is correlated with higher reported reliability on average compared to reported reliability not using the standard.[272]

Current efforts are underway to make more reliability data publicly available. The Institute of Electrical and Electronics Engineers (IEEE) Distribution Reliability Working Group conducts an annual voluntary "benchmarking" exercise wherein utilities voluntarily submit daily SAIDI and SAIFI data to this IEEE Working Group. IEEE then calculates annual averages for these measures, both including and excluding major event days. Figure 60 presents the SAIDI results from this voluntary reporting standard; it suggests that electric customers endured on average between 85 and 158 minutes of outages in 2013, which represents some improvement over the past decade.[273] Beginning in 2011, this benchmarking exercise began requesting reliability metrics from utilities distinguishing interruptions that originate at the distribution system as opposed to the transmission system.[274]

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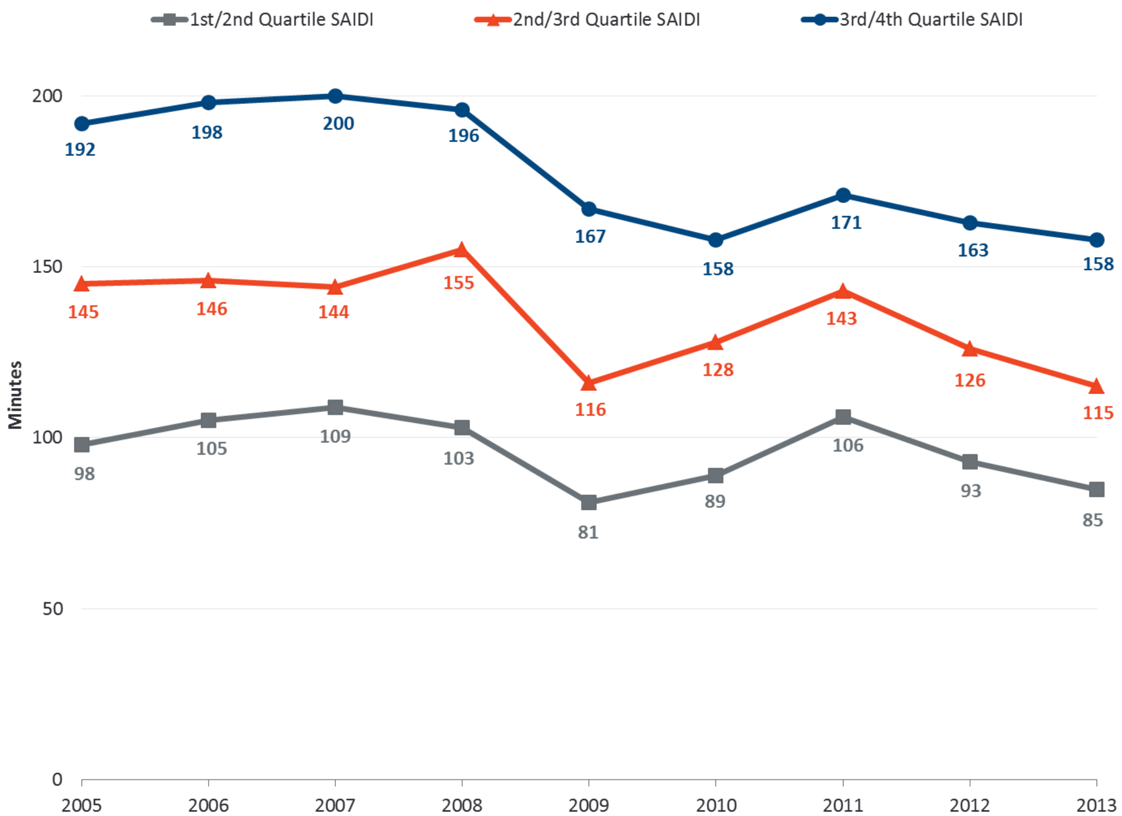
272 Eto, Joseph H., Kristina Hamachi LaCommare, Peter Larsen, *et al.*, *An Examination of Temporal Trends in Electricity Reliability Based on Reports from U.S. Electric Utilities*, LBNL-5268E, January 2012, available at http://emp.lbl.gov/sites/all/files/lbnl-5268e.pdf.

273 The differences between the LBNL study and the IEEE data may be driven by a different sample of participants; however in both studies the 2005-2008 period displayed the highest SAIDI levels.

274 IEEE, IEEE Benchmarking 2011 Results, based on Distribution Reliability Working Group Meeting, San Diego, CA, July 24, 2012, available at http://grouper.ieee.org/groups/td/dist/sd/doc/2012-07-01-Benchmarking-Results-2011.pdf.

Figure 60
2013 SAIDI Quartiles—All Utilities



Source: Adapted from IEEE Benchmark Year 2014: Results for 2013 Data, presented at Distribution Reliability Working Group General Meeting, Washington, DC, July 29, 2014. Available at http://grouper.ieee.org/groups/td/dist/sd/doc/2014-08-Benchmarking-Results-2013.pdf.

In addition, EIA is beginning to collect, on a mandatory basis, SAIDI and SAIFI from utilities across the US. Through this collection, certain utilities will be required to report annual SAIDI and SAIFI "minus loss of supply"; in other words, annual SAIDI and SAIFI calculated only including events that are initiated on the distribution system.[275]

The distribution system's inherently greater exposure and complexity result in its greater vulnerability to disruptions. The distribution system is, however, aided by the relatively lower number of customers affected by any individual disruption. Like the transmission system, a number of actions can be undertaken to increase resiliency. These include vegetation management, targeted undergrounding, overhead distribution reinforcement, enhanced cyber security, load reduction, smart grid technologies for self-healing and asset monitoring, restoration management, and damage prediction and response. These methods may be used in different combinations depending on the economics and feasibility for any one utility.

275 See U.S. Energy Information Administration, Survey Forms, online at http://www.eia.gov/survey/#eia-861 for survey form and instructions.

2. System Vulnerabilities

a. Aging Equipment

There is a general concern that the country's electric infrastructure is old and obsolete. For example, a survey of more than 500 utility professionals across the country revealed that "old infrastructure" is the most common concern.[276] Ameren Missouri's grid (referring to both transmission and distribution infrastructure) is "heavily populated with 40–60 year old equipment that is at risk of failure, obsolete, and inefficient compared to modern equipment."[277] Similarly, a 2013 American Society of Civil Engineers (ASCE) report expressed concern with the nation's energy infrastructure, citing an aging electrical grid and distribution facilities that have resulted in an increasing number of power disruptions.[278] However, the concern is not universally shared.[279]

Distribution utilities often spend an amount equal to 1 to 2% of their depreciated plant in service on refurbishment, in order to maintain reliability.[280] Although the amount of capital invested in distribution networks has grown faster than load in recent years, there is nevertheless concern that current levels of investment are inadequate to replace what is perceived to be an aging infrastructure.[281] For example, in 2011 the ASCE projected annual distribution investment needs for the 2015–2040 period of $25.4-$30.2 billion (in 2010 dollars), noting that the level of distribution investment from 2001–2010 would fall far short of this mark.[282] In particular, they project large investment gaps for the Southeast (SERC), Mid-Atlantic (RFC), and West (WECC).

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276 UtilityDive, *The State of the Electric Utility*, 2014, download available at http://www.utilitydive.com/library/2014-state-of-the-electric-utility/.

277 Ameren Missouri, 2014 Integrated Resource Plan, Chapter 7. Transmission & Distribution NP, available at https://www.ameren.com/-/media/Missouri-Site/Files/environment/renewables/irp/irp-chapter7.pdf?la=en.

278 American Society of Civil Engineers, *2013 Report Card for America's Infrastructure*, March 2013, available at http://www.infrastructurereportcard.org/a/documents/2013-Report-Card.pdf.

279 Haugen, Dan, "Are Utilities' Concerns about Aging Infrastructure Overblown?" *Midwest Energy News*, posted March 4, 2014, online at http://www.midwestenergynews.com/2014/03/04/are-utilities-concerns-about-aging-infrastructure-overblown/.

280 Electric Power Research Institute, *Estimating the Costs and Benefits of the Smart Grid: A Preliminary Estimate of the Investment Requirements and the Resultant Benefits of a Fully Functioning Smart Grid*, Technical Report 1022519, Final, March 29, 2011, download available at http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000000001022519.

281 Aggregate data from utilities required to submit FERC Form 1 suggests that net distribution assets grew, in nominal terms, by 5.2% per year between 2003 and 2013.

282 American Society of Civil Engineers, *Failure to Act—The Economic Impact of Current Investment Trends in Electricity Infrastructure*, 2011, available at http://www.asce.org/uploadedFiles/Infrastructure/Failure_to_Act/SCE41%20report_Final-lores.pdf. Note that part of the investment needs estimated by ACSE reflects upgrades to smart grid technologies (discussed in detail below). However, their estimate of distribution needs is also motivated by "the

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Nonetheless, in recent years, blue-sky equipment failure (*i.e.,* equipment failure in which neither weather nor other external factors are the proximate cause) is less important as a cause for outages and other disturbances than weather events, according to the OE-417 data presented in Figure 58 and Figure 59. Even though portions of the distribution infrastructure may still have many years of useful life, the new challenges discussed below present an opportunity to improve reliability and resiliency and to make the grid smarter, more flexible, and more loss-efficient, using new technologies in the face of new needs.

b. Severe Weather and Storms

The increasing incidence of major storms, and the extent and duration of power outages following these storms, has increased public awareness of the importance of grid resiliency to natural phenomena. For example, Hurricane Irene caused 6.69 million reported customer outages across 14 states and the District of Columbia in August 2011. In October and November of 2012, Hurricane Sandy and the nor'easter that occurred shortly after Sandy caused 8.86 million outages across 20 states and the District of Columbia. Both storms caused severe damage to the transmission and distribution infrastructures of several utilities in the Mid-Atlantic and Northeast.[283] Other recent extreme weather events that have also caused extensive damage to the electric system include the June 2012 Derecho, blizzards in February 2010, Hurricane Ike in 2008, and Hurricane Katrina in 2005.[284] There is increasing consensus that storms will continue to be more frequent and severe than in recent history, and that these storms will pose increasing risks to the electric system, and especially local distribution systems.[285] As depicted in Figure 61,

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aging of local distribution networks," noting the connection between power outages and component failures.

283 U.S. Department of Energy, Office of Electricity Delivery and Energy Reliability, *Comparing the Impacts of Northeast Hurricanes on Energy Infrastructure*, April 2013, available at http://energy.gov/sites/prod/files/2013/04/f0/Northeast%20Storm%20Comparison_FINAL_041513c.pdf. See also Gray, Edward, Electric Distribution Resiliency for Major Storm Events, presented at the DOE Office of Electricity Delivery and Energy Reliability Resilient Electric Distribution Grid R&D Workshop, Washington, DC, June 11, 2014 ("Gray 2014"), available at http://e2rg.com/workshops/Plenary_Ed-Gray.pdf.

284 A derecho is a line of intense, widespread, and fast-moving windstorms and sometimes thunderstorms that moves across a great distance and is characterized by damaging winds. In North America they most commonly affect Midwestern states in spring and summer months.

285 See, for example, Intergovernmental Panel on Climate Change (IPCC), 2013: *Summary for Policymakers* available at

http://www.climatechange2013.org/images/report/WG1AR5_SPM_FINAL.pdf; IPPC, *Climate Change 2013: The Physical Science Basis,* Working Group I Contribution to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change; and Department of Energy (New York: Cambridge University Press, 2013), available at

http://www.climatechange2013.org/images/report/WG1AR5_ALL_FINAL.pdf; and U.S. Department of Energy, *U.S. Energy Sector Vulnerabilities to Climate Change and Extreme Weather,* DOE/PI-0013,

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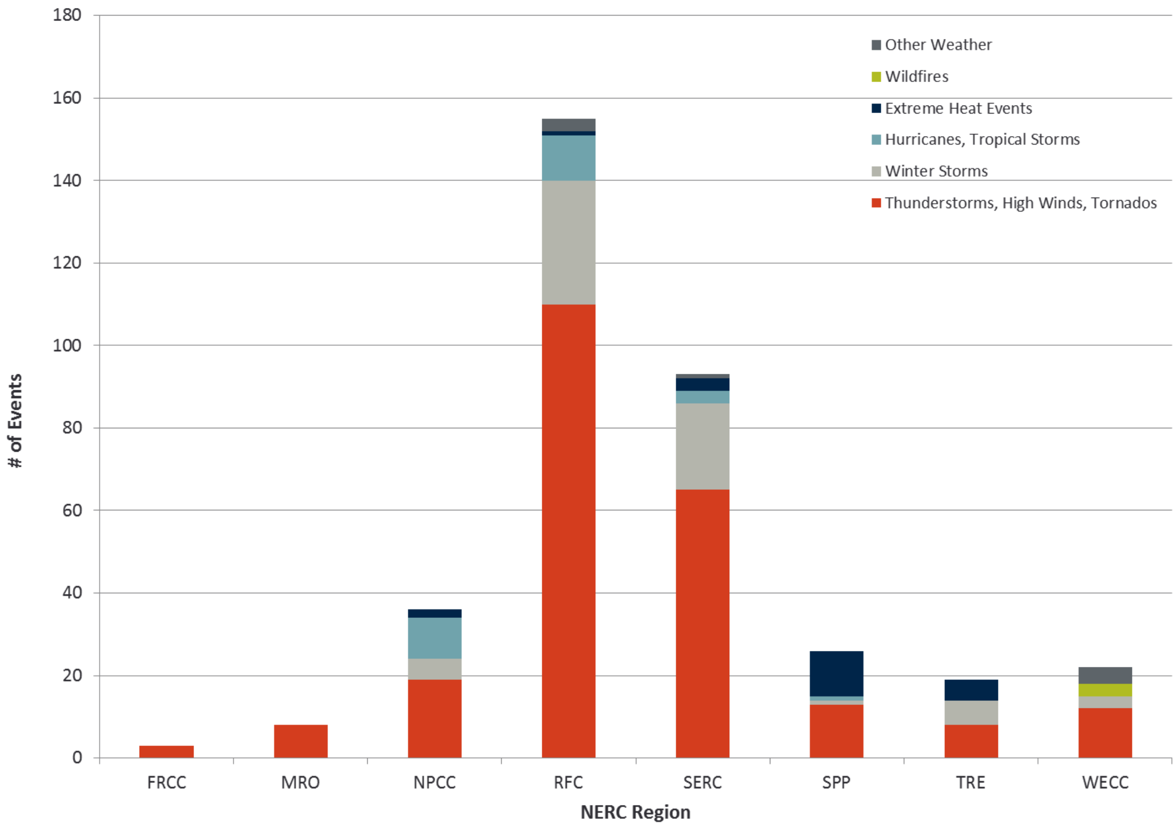
the level of the threat varies by region of the country, with weather-related disturbance events in recent years concentrated in the Mid-Atlantic (RFC) and Southeast (SERC).

Figure 61
Disturbance Events Due to Extreme Weather, by NERC Region, 2011–August 2014



Source and Notes: Electric Disturbance Events (OE-417) database, Office of Electricity Delivery & Energy Reliability, Department of Energy, https://www.oe.netl.doe.gov/oe417.aspx. Events in the OE-417 database were categorized by The Brattle Group based on the text description provided in the "Event Type" field, using only weather-related events. See footnote 269 for a more complete description of this data and its limitations.

Damage to the distribution system, rather than the transmission system, is more often the cause of loss of service, in part because of the redundancy built into the transmission system. For example, Table 11 demonstrates that recent severe storms in Maryland resulted in vast numbers of service interruptions, with the immediate causes of those interruptions limited to the distribution system, but scattered throughout varying components of the distribution infrastructure.

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July 2013, available at http://energy.gov/sites/prod/files/2013/07/f2/20130716-Energy%20Sector%20Vulnerabilities%20Report.pdf.

Table 11
Total Consumer Interruptions Associated with System Components after Three Major Storms Affecting Maryland

System Components	Snowmageddon 2/2/2010 – 2/12/2010			Hurricane Irene 8/27/2011 – 9/6/2011			Derecho 6/29/2012 – 7/8/2012		
	BGE	Pepco	Potomac Edison	BGE	Pepco	Potomac Edison	BGE	Pepco	Potomac Edison
Transmission Lines	0	0	0	0	0	0	0	0	0
Transmission Substations	0	0	0	0	0	0	0	0	0
Substation Supply Lines	4,503	28,637	2,662	65,045	89,233	4,370	113,502	270,012	17,185
Distribution Substations	0	0	0	0	0	0	0	0	852
Fuses	47,742	16,571	1,998	253,622	30,058	3,847	248,710	49,387	3,266
Distribution Lines	38,674	198,508	5,034	182,406	274,382	7,755	160,544	598,161	51,819
Reclosers	48,670	4,579	2,368	238,565	11,405	3,557	216,268	18,076	16,954
Transformers	1,613	2,728	416	9,007	3,869	173	14,492	17,656	391
Service Lines	1,026	740		7,750	1,366		9,265	5,271	
Total Customer Interruptions	**142,228**	**251,763**	**12,478**	**756,395**	**410,313**	**19,702**	**762,781**	**958,563**	**90,467**

Source: Office of Governor Martin O'Malley, *Weathering the Storm: Report of the Grid Resiliency Task Force*, September 24, 2012. Available at http://www.governor.maryland.gov/documents/GridResiliencyTaskForceReport.pdf.

Following major power outages caused by extreme weather events, there is usually increased interest from customers, utilities, and public utility commissions in investments in distribution resiliency, known as asset hardening. However, asset hardening can have significant costs and somewhat uncertain and difficult-to-quantify benefits.[286]

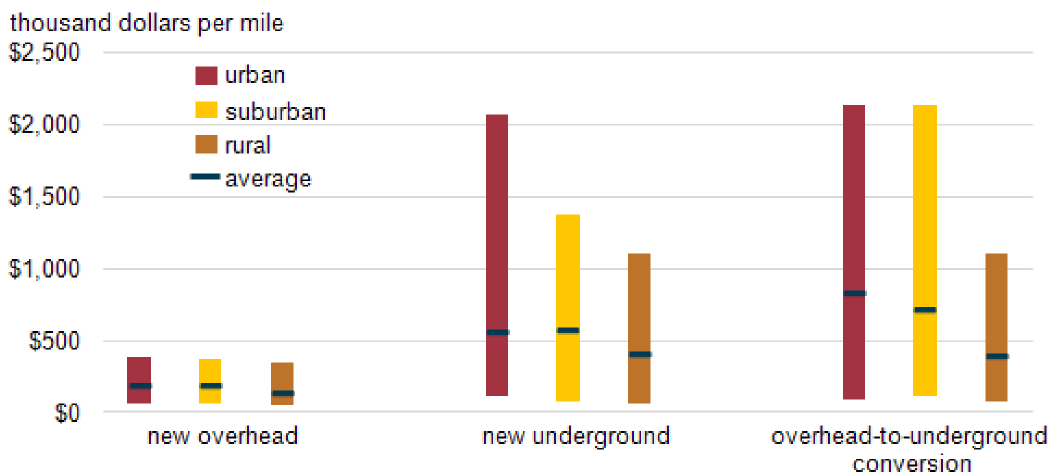
An example is the frequent call following major storm events for burying or "undergrounding" power lines.[287] EEI has estimated that underground distribution lines can cost five to 10 times more than overhead lines; Figure 62 provides a comparison of the average costs, as well as the

286 Zarakas, William P., Sanem Sergici, Heidi Bishop, *et al.*, "Utility Investments in Resiliency: Balancing Benefits with Cost in an Uncertain Environment." *The Electricity Journal* (27(5), June 2014: 31–41 ("Zarakas, *et al.*, 2014"), available at http://www.sciencedirect.com/science/article/pii/S1040619014000967.

287 See, for example, CNN.com, Opinion, Why we should bury the power lines, online at http://www.cnn.com/2012/07/02/opinion/frum-buried-lines/ and DeBonis, Mike, Storm rekindles questions about 'undergrounding' power lines, *The Washington Post*, D.C. Politics, July 2, 2012, online at http://www.washingtonpost.com/local/dc-politics/storms-rekindle-questions-about-undergrounding-power-lines/2012/07/02/gJQA1miMJW_story.html.

range of costs, associated with each.[288] Several states have undertaken studies of complete or partial undergrounding of the distribution system, with most concluding that complete undergrounding is cost prohibitive.[289] For example, a 2009 study in Houston, Texas concluded that undergrounding the entire regional distribution system would cost $35 billion.[290] A 2003 study in North Carolina estimated that undergrounding the state's distribution system would increase the average residential customer's monthly bill by more than 125%.[291] Instead, several studies have concluded that selective undergrounding may in some cases have benefits that exceed the costs.[292] This example underlines the need to weigh the relative costs and benefits in evaluating resiliency investments.

Figure 62
Cost-Per-Mile (Range and Average) for Distribution Power Lines



Source and Notes: EIA Today In Energy, July 25, 2012. Overhead to underground conversion is typically more expensive than new underground construction because conversion projects need to work around existing infrastructure, including sidewalks and non-electric utility infrastructure, whereas new underground construction is typically done in newly developed areas.

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[288] Hall, Kenneth L., *Out of Sight, Out of Mind 2012* , Edison Electric Institute, January 2013), Chart provided by EIA based on 2009 data. http://www.eei.org/issuesandpolicy/electricreliability/undergrounding/Documents/UndergroundReport.pdf.

[289] *Id.,* p. 35.

[290] City of Houston Mayor's Task Force Report, *Texas Electric Service Reliability in the Houston Region*, April 21, 2009, available at http://www.houstontx.gov/mayor/taskforce-electricity.pdf.

[291] North Carolina Public Staff Utilities Commission, *The Feasibility of Placing Electric Distribution Facilities Underground*, Report to the North Carolina Natural Disaster Preparedness Task Force November 2003, available at http://www.ncuc.commerce.state.nc.us/reports/undergroundreport.pdf.

[292] Edison Electric Institute, *Before and After the Storm: A compilation of recent studies, programs, and policies related to storm hardening and resiliency*, Update March 2014, pp. 1-2, available at http://www.eei.org/issuesandpolicy/electricreliability/mutualassistance/Documents/BeforeandAftertheStorm.pdf.

Current resource adequacy requirements (relevant for generation systems) are usually based on "1-day-in-10-year" 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 benchmarking 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" (VOLL) concept as a means of quantifying benefits.

Using VOLL to measure benefits is still being tested and is not an industry standard. It involves using customer surveys to estimate the value that customers place upon reliability or their "willingness to pay." [293]

c. Cyber and Physical Attacks

As discussed in the transmission section, cyber and physical attacks on the electric grid represent additional threats to electric reliability. Both types of attacks are also relevant to the distribution system and deserve brief mention here, though much of the fuller discussion in the transmission section applies to the distribution sector as well. Cyber-attacks are primarily relevant at the distribution level because emerging technologies such as smart grid systems, advanced metering infrastructure, and plug-in electric vehicles will exponentially increase the number of access points to the grid, and thus raise the possibility of increased risks. However, as previously discussed, the most comprehensive cyber-security standards (the NERC-CIP standards) do not apply to the distribution system. Physical attacks are also relevant, in part because of their apparent prevalence, as suggested by the OE-417 data presented in Figure 58 above. However, many of the reported disturbances that can be classified as physical attacks are acts of vandalism or other events that have extremely localized effects, as opposed to the systemic effects that an attack on a key transmission line might have.

Data on electric disturbances collected by the DOE suggests that until now, cyber and physical attacks have had very minimal impacts on customers, although the number of physical incidents is significant.[294] Nonetheless, assessing risk in this area is difficult, which complicates decisions of whether and how to protect against these threats.

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293 For example, a meta-analysis authored by Lawrence Berkeley National Laboratory relied on 28 value of service surveys from 10 different utilities over a 26-year period, citing the use, for more than 20 years, of value-based reliability concepts in assessing distribution system reinforcements. The utilities whose VOLL surveys were cited include Bonneville Power Administration, Duke Energy, Pacific Gas & Electric, Salt River Project, and Southern Company, among others. See Sullivan, Michael J., Matthew Mercurio, and Josh Schellenberg, *Estimated Value of Service Reliability for Electric Customers in the United States*, prepared for the U.S. Department of Energy Office of Electricity Delivery and Energy Reliability, LBNL-2132E, June 2009, pp. xv-xvi, xviii, available at http://certs.lbl.gov/pdf/lbnl-2132e.pdf.

294 This can be seen in the OE-417 data presented in Figure 58 and Figure 59.

3. State Regulation of Distribution Investment and Operations

Cost recovery at the distribution level is regulated by individual states for the distribution systems of the electric utilities under their jurisdiction, which typically, though not always, is limited to investor-owned utilities.[295] Operational expenses are typically recovered in base rates after regulatory review, while capital expenditures related to the distribution plant are included in a utility's rate base and depreciated over the asset's useful life. Investor-owned electric utilities earn an allowable rate of return on capital expenditures, while depreciation expenses are included in base rates. Traditionally, the most common practice by which utilities recover costs is through a general rate case, where it seeks to change rates based on changes in operational expenses or new plant additions. Rate cases typically involve a "test year," in which a utility calculates and summarizes the costs it will incur. This test year approach can be problematic if there are large unforeseen reliability events after rates are set, as such events tend to increase both the operational expenses and needed capital investments to repair damaged infrastructure.[296]

As a result, regulators and utilities in some jurisdictions have developed alternative approaches to cost recovery, including cost deferral, rate adjustment mechanisms, formula rates, and storm reserve accounts.[297] The increasing frequency and severity of storms and the resulting problems with reliability and resiliency have also resulted in a shift in regulatory focus. This includes post-storm audits of utility performance and increased regulatory interest in the grid resiliency benefits of distributed generation and smart grid technologies.[298] Another notable development is changes to the regulatory framework that are intended to incentivize improvements in reliability and resiliency to storm events. These changes have taken several forms, including performance-based formula rates or other outcome-based incentives (in Illinois and New York), alternate test years that are conditional upon the attainment of various performance metrics (Maryland), and performance standards that are accompanied by financial penalties for non-compliance (Connecticut and Massachusetts).[299]

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295 Local elected or appointed governing boards, rather than state public utility commissions, usually regulate publicly-owned and cooperatively-owned electric utilities. However, there are some states where the public utility commission does have some level of regulatory oversight of these non-IOUs, and in some cases that includes distribution. Similar ratemaking principles are followed in these two sectors.

296 Edison Electric Institute, Before and After the Storm: A compilation of recent studies, programs, and policies related to storm hardening and resiliency, Update March 2014, p. 19, available at http://www.eei.org/issuesandpolicy/electricreliability/mutualassistance/Documents/BeforeandAftertheStorm.pdf.

297 *Id.,* pp. 19–26.

298 *Id.,* pp. 28–29.

299 *Id.,* pp. 27–28.

4. Detection of Outages and Response Times

A key part of resiliency is the distribution system operator's ability to quickly return to normal service after a disturbance, regardless of its cause. While the duration of the outage is the most obvious and widely-used benchmark in evaluating this part of resiliency, the definition of a "quick" return to service is context-specific and will depend on factors such as the extent of the damage, and whether damage is limited to the distribution system or is also at the transmission or even generation level. In any case, the ability to respond and restore the distribution system is greatly dependent on the ability of the local distribution system operator to get timely and accurate outage information.[300]

Traditionally, utility outage management systems have relied on calls from customers to identify and locate the source of outages. The benefits of AMI will be more fully discussed below, but one key benefit in terms of distribution system resiliency is the ability for utilities to be aware of distribution outages in real-time. Restoration alert systems built into the AMI allow utilities to see the status of individual meters and focus restoration efforts where needed. For example, following Hurricane Sandy, one Maryland utility was able to restore power much more quickly in the areas using AMI than in those areas that were not.[301]

5. Microgrid Pilot Projects

Another development which may provide substantial benefits in terms of resiliency at the customer level is the advent of microgrids. Lawrence Berkeley National Laboratory defines a microgrid as "a localized grouping of electricity sources and loads that normally operates connected to and synchronous with the traditional centralized grid, but that can disconnect and function autonomously as physical and/or economic conditions deteriorate."[302] Microgrids necessarily include some amount of distributed generation in addition to load, but may also rely in part on storage. This ability to function autonomously can improve both the ability to withstand disturbances at the primary distribution level, and to maintain minimum service during disturbances, particularly if those disturbances occur at the generation or transmission level. The ability to re-connect to the main grid, and to possibly help in re-powering the network, is another key feature.

Several microgrid pilots are currently in operation, including projects at universities, military bases, and even a jail, as well as utility-operated projects.[303] Increased experience with these pilot

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300 *Id.* Other factors include the availability of increased labor, standby equipment, and restoration materials.

301 Silver Spring Networks, *How the Smart Grid Makes Restoration Faster and Easier for Utilities*, White Paper, 2013. http://www.silverspringnet.com/outage/pdfs/SilverSpring-Whitepaper-Outage.pdf.

302 Lawrence Berkeley National Laboratory, About Microgrids, online at http://building-microgrid.lbl.gov/about-microgrids.

303 *Id.,* Examples of Microgrids, online at http://building-microgrid.lbl.gov/examples-microgrids.

programs will allow for a better understanding of the costs and benefits of this alternative structure to the traditional distribution grid.

C. Smart Grid and Advanced Metering Infrastructure

"Smart grid" is a blanket term that widely refers to the application of advanced information, communication, and control technologies across the electric power sector to improve the reliability, efficiency, and functionality of the electric transmission and distribution system. Major elements of a smart grid include automation and two-way communication between the components of an electric system.

The introduction of advanced meters that can receive data from, and send information back to, utilities is having significant impacts across the electric power sector. For example, a smart grid is able to respond more rapidly to outage occurrences and possible even "self-heal" in the event of a major disturbance. However, the Electric Power Research Institute has stated that to gain the full advantage of smart grid-related systems such as advanced metering infrastructure (AMI), geographic information systems (GIS), OMS, data analytics, and workforce management systems, these systems must all be well-integrated.[304] This systems integration is a task that will require years and large capital investments, just as it has in other parts of the U.S. economy.

AMI represents an upgrade to the metering system that allows for digital two-way communication between the utility and the meter (and ultimately the customer). This enables the utility to remotely collect granular electricity consumption data from each meter measured in short time intervals. Interval meters that measured energy use every 15 minutes (or with similar frequency) have existed for years, but smart meters typically provide additional benefits such as near real-time data and outage notification. This functionality has a number of operational and reliability benefits, including avoided manual meter reading costs, remote connect/disconnect capability, faster outage detection, and improved load research and forecasting. As technology for reliability and resiliency continues to improve, smart grid applications become an important tool in mitigating disturbances to the power system. In addition, AMI also allows a number of new services to be offered to the customer, which allows customers to better manage their energy use. By reducing or shifting their electricity consumption, customers will have the opportunity to lower their bills and utilities will be able to defer or avoid resource investment costs.[305]

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304 Carson, Phil. "EPRI: Sandy exposes smart grid limits, and maturity," *Intelligentutility.com*, November 19, 2012, online at http://www.intelligentutility.com/article/12/11/epri-sandy-exposes-smart-grid-limits-and-maturity.

305 Faruqui, Ahmad, Ryan Hledik, and John Tsoukalis, "The Power of Dynamic Pricing," *The Electricity Journal* 22(3), April 2009: 42–56.

1. Smart Meter Roll-Out

Deployment of smart meters is poised for significant growth over the next decade. FERC's annual review of advanced meters released in October 2013 estimates penetration rates of 30%[306] based on a review completed by the Institute for Electric Innovation, which found that 46 million smart meters are installed.[307]

Table 12
Estimates of Advanced Meter Penetration

Source of No. of Advanced Meters	Reference Date (Month/Year)	Number of Advanced Meters (millions)	Total Number of Meters (millions)	Advanced Meter Penetration Rates (advanced meters as a % of total meters)
2008 FERC Survey	Dec 2007	6.7 [1]	144.4 [1]	4.7%
2010 FERC Survey	Dec 2009	12.8 [2]	147.8 [2]	8.7%
2012 FERC Survey	Dec 2011	38.1 [3]	166.5 [3]	22.9%
EIA-861 Annual Survey	Dec 2011	37.3 [4]	151.7 [4]	24.6%
Institute for Electric Efficiency	May 2012	35.7 [5]	151.7 [4]	23.5%
Innovation Electricity Efficiency	July 2013	45.8 [6]	151.7 [4]	30.2%

Sources:
[1] FERC, Assessment of Demand Response and Advanced Metering staff report (December 2008).
[2] FERC, Assessment of Demand Response and Advanced Metering staff report (February 2011).
[3] FERC, Assessment of Demand Response and Advanced Metering staff report (December 2012).
[4] Energy Information Administration, Form EIA-861 Data File 2 and Data File 8 for 2011 (http://www.eia.gov/cneaf/electricity/page/eia861.html).
[5] Institute for Electric Efficiency, Utility-Scale Smart Meter Deployments, Plans & Proposals (May 2012).
[6] Innovation Electricity Efficiency, Utility-Scale Smart Meter Deployments: A Foundation for Expanded Grid Benefits (August 2013).

Note: Commission staff has not independently verified the accuracy of EIA or IEE data.

Source: FERC, Assessment of Demand Response and Advanced Metering, Staff Report, October 2013, available at http://www.ferc.gov/legal/staff-reports/2013/oct-demand-response.pdf, p. 3.

DOE's Recovery Act Smart Grid Investment Grant program has supported the deployment of 15 million smart meters, almost a third of the total smart meters currently in operation.[308]

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306 FERC, *Assessment of Demand Response and Advanced Metering*, Staff Report, October 2013, available at http://www.ferc.gov/legal/staff-reports/2013/oct-demand-response.pdf.

307 Institute for Electric Innovation (also known as Innovation Electricity Efficiency), *Utility-Scale Smart Meter Deployments: A Foundation for Expanded Grid Benefits*, August 2013, available at http://www.edisonfoundation.net/iee/Documents/IEE_SmartMeterUpdate_0813.pdf.

308 Smartgrid.gov, Advanced Metering Infrastructure and Customer Systems, online at https://www.smartgrid.gov/recovery_act/deployment_status/ami_and_customer_systems. Smart meters deployed through June 30, 2014, as updated on website on September 3, 2014.

Figure 63
Smart Meters Deployed Through Recovery Act Smart Grid Investment Grant

Source and notes: Smartgrid.gov, Advanced Metering Infrastructure and Customer Systems, online at https://www.smartgrid.gov/recovery_act/deployment_status/ami_and_customer_systems. Smart meters deployed through June 30, 2014, as updated on website on September 3, 2014.

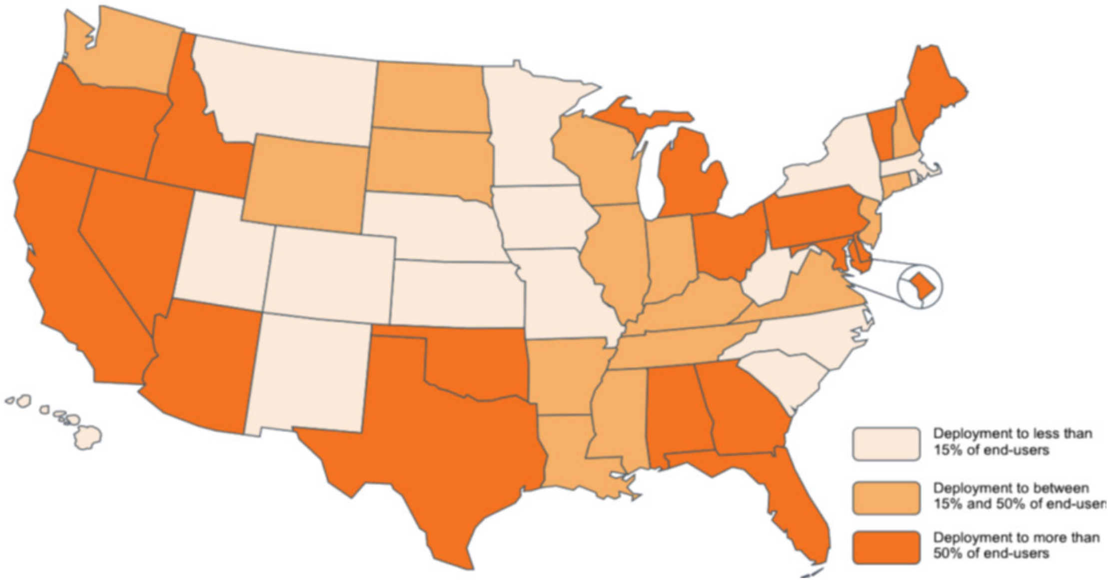
The deployment of smart meters has occurred across the U.S. with states in each region of the country expected to achieve greater than 50% penetration of smart meters by 2015, as shown in Figure 64.[309] The growth in smart meters is expected to continue; one recent projection of smart metering penetration suggests that penetration in North America will reach 91% by 2022.[310]

309 Institute for Electric Innovation (also known as Innovation Electricity Efficiency (IEE), Utility-Scale Smart Meter Deployments: A Foundation for Expanded Grid Benefits, August 2013 ("IEE 2013"), p. 2, available at

http://www.edisonfoundation.net/iee/Documents/IEE_SmartMeterUpdate_0813.pdf.

310 See Telefónica S.A., M2M: 800 million electric smart meters to be installed globally by 2020, January 30, 2014, online at https://m2m.telefonica.com/m2m-media/m2m-news/item/630-m2m-800-million-electric-smart-meters-to-be-installed-globally-by-2020.

Figure 64
Expected Smart Meter Deployment by State by 2015



Source: Institute for Electric Innovation (also known as Innovation Electricity Efficiency (IEE), Utility-Scale Smart Meter Deployments: A Foundation for Expanded Grid Benefits, August 2013 ("IEE 2013"), p. 2, available at http://www.edisonfoundation.net/iee/Documents/IEE_SmartMeterUpdate_0813.pdf.

2. Operational Benefits

One of the primary appeals of AMI is the suite of operational improvements, which are enjoyed both by the utility and the customer. A brief summary of the most important benefits follows.[311]

- Automation of meter reading avoids labor costs associated with manual meter reading.
- Reliability improvements accrue as a result of remote sensing that allows for quicker detection of outages and localization of the problem. Real-time outage information (as opposed to relying on calls from customers) can improve efficiency of truck and resource deployments during storm recovery operations.

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311 This list of benefits relies in large part on "business case" documents filed in regulatory proceedings by utilities seeking approval for the implementation of smart meters. These include ComEd, available at https://www.sgiclearinghouse.org/CostBenefit?q=node/4566&lb=1; BC Hydro, *Smart Metering & Infrastructure Program Business Case*, n.d., available at https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/projects/smart-metering/smi-program-business-case.pdf; Southern Cal Edison, *Edison SmartConnect™ Deployment Funding and Cost Recovery, Volume 2: Deployment Plan*, U 338-E, before the Public Utilities Commission of the State of California, LAW #1386192, July 31, 2007, available at http://sites.energetics.com/MADRI/toolbox/pdfs/business_cases/sce_vol2_deployment.pdf; and Delmarva Power, *Advanced Metering Business Case Including Demand Side Management Benefits*, Report for Delaware before the Delaware Public Service Commission, Docket No. 07-28, August 29, 2007, available at http://www.depsc.delaware.gov/electric/11528%20Cohen%20Ex2.pdf. Also see Gray 2014.

- The ability to remotely connect or disconnect a meter saves on technician visits and truck rolls.
- Remote connection and disconnection has the ability to limit unaccounted for energy and consumption on inactive meters—costs that are otherwise socialized and recovered through rate increases to all ratepayers.
- Finally, the ability to collect interval data across the load points connected to a given transformer may allow utilities to identify transformers that are at risk of failure, allowing those to be replaced before emergencies occur.

In business case documents reviewed for several utilities, these operational benefits account for anywhere from 57% to 100% of total benefits.[312]

3. Distribution Automation

Another key benefit of AMI that is related to the operations benefits discussed above is enhanced distribution automation. Distribution automation is not a new concept; feeder devices are already used to improve reliability and systems performance without manual intervention.[313] However, the installation of AMI, including not only smart meters but also remote sensing devices at various points on the distribution grid, allows for further optimization of automation processes. Essentially, AMI promises increases in communication regarding system conditions throughout the grid, enabling more automated functions with the ability to enhance system efficiency.

For example, with automatic voltage and VAR control, sensors, controls, and communications systems can work together in a coordinated fashion to automatically detect and respond to changes in the system power factor in order to achieve a more efficient level and therefore reduce line losses. Conservation voltage reduction (CVR) would be utilized as an efficiency improvement strategy that would carefully control the voltage along a feeder such that the farthest point in the system maintains the ANSI minimal voltage requirements. This strategy has the potential to reduce losses by up to 2% within the distribution system.[314] This type of automated control could also be extended to switches, to intelligently and automatically turn on or off specific circuits of the grid in order to isolate and minimize the impacts of an outage. This would reduce the number of customers affected by the outage and can also lead to improvements

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[312] See, *e.g.*, ComEd, *op. cit.* at p. 2; BC Hydro, *op. cit.* at p. 9; and Southern Cal Edison, *op. cit.* at p. 14.

[313] Hart, David G. "How Advanced Metering Can Contribute to Distribution Automation." *IEEE Smart Grid*, August 2012 ("Hart 2012"), online at http://smartgrid.ieee.org/august-2012/644-how-advanced-metering-can-contribute-to-distribution-automation.

[314] See, *e.g.*, Schneider, K.P., F.K. Tuffner, J.C. Fuller, and R. Singh, *Evaluation of Conservation Voltage Reduction (CVR) on a National Level,* Pacific Northwest National Laboratory, prepared for the U.S. Department of Energy, PNNL-19596, July 2010, p. 9, online at http://www.pnl.gov/main/publications/external/technical_reports/PNNL-19596.pdf.

in power quality. While automatic voltage and VAR control are already prevalent,[315] the deployment of AMI can enable higher levels of conservation by using information from smart meters along a distribution feeder to further optimize voltage levels.[316]

4. How Smart Meters Impact Usage

The deployment of smart meters to retail customers also provides opportunities for the utility to collect data and provide consumers with information on their usage; this is the infrastructure that increases utilities' ability to deploy time-varying rates and to interact with enabling technologies, such as "smart appliances."[317] There are a number of ways in which smart meters can be used, many of which entail additional costs and processes:

- Information: Smart meters allow for more granular (*e.g.*, 15 minute) data to be collected, allowing the utility to know how consumers use power and the consumer to track their own energy usage more closely.[318]
- Time-Varying Rates (TVR): Electricity prices change continuously at the wholesale level, yet traditional retail rates are fixed throughout a month, season, or year. Smart meters facilitate the implementation of time-varying rates that will not necessarily track wholesale prices, but begin to provide price signals to consumers about times of the day or during certain events where wholesale prices tend to be higher. A summary of the different types of time-varying rates is shown in Table 13.[319]
- Enabling Technologies: For price signals to be useful, consumers must be able to respond by adjusting their usage up or down accordingly. Connecting enabling technologies that are able to directly receive information on either price signals or reliability events from the utility greatly increases the impact that smart meters can have on electricity usage, especially during peak load hours. Consumers can respond through their own actions or through the use of intelligent devices, such

[315] Energy and Environmental Economics and EPRI Solutions, "Preliminary Assessment: Value of Distribution Automation Applications," prepared for the California Energy Commission, PIER. Publication No. CEC 500-2007-028, p. 1.

[316] Hart 2012.

[317] Enabling technologies are able to receive a signal from a smart meter about prices and/or reliability events and respond accordingly depending on its settings.

[318] Christos Polyzois, *Slicing and Dicing Smart Grid Data,* IEEE Smart Grid Web Portal, February 2011. Available at: http://smartgrid.ieee.org/ieee-smart-grid

[319] Faruqui, Ahmad, Ryan Hledik, and Neil Lessem, "Smart by Default," Public Utilities Fortnightly 152(8), August 2014, p. 26 ("Faruqui, Hledik, and Lessem 2014"), online at http://www.fortnightly.com/fortnightly/2014/08/smart-default

as water heaters and thermostats that automatically respond to changes in wholesale market prices.[320]

Table 13
Common Forms of Time-Varying Rates

Form	Description	Requires Smart Meter?
Critical Peak Pricing (CPP)	Charges customers a higher rate in a small percentage of critical peak periods, in return for lower prices throughout the rest of the year.	✓
Peak Time Rebates (PTR)	Offers customers a rebate for conserving during these same critical peak periods. Rates remain constant otherwise.	✓
Real-Time Pricing (RTP)	Offers customers the chance to respond to prices that change with wholesale rates on an hourly basis (or in some pilot projects even more frequently).	✓
Time of Use (TOU)	Offers a lower rate during certain hours of the day when energy is cheaper to produce and at a higher rate during peak periods when it is the most expensive. These rates and hours are established in advance.	
Variable Peak Pricing (VPP)	Similar to TOU, except the peak rates vary with market conditions.	✓

Sources: Faruqui, Ahmad, Ryan Hledik, and Neil Lessem, "Smart by Default," *Public Utilities Fortnightly 152(8),* August 2014, p. 26, online at http://www.fortnightly.com/fortnightly/2014/08/smart-default; AEP Ohio, *gridSMART Demonstration Project: A Community-Based Approach to Leading the Nation in Smart Energy Use, Department of Energy (DOE) Smart Grid Demonstration Project (SGDP)*, Final Technical Report, June 2014, p.128; ComEd, *The ComEd Residential Real-Time Pricing Program Guide to Real-Time Pricing*, 2013–2014, p.5. Available at https://www.comed.com/Documents/customer-service/rates-pricing/real-time-pricing/RRTPProgramGuide.pdf.

Smart meters are needed to provide CPP, PTR, RTP, and VPP because they provide the customer with real-time market information on peak demand and prices. TOU rates can be established in

[320] For an example of the latter, see Pacific Northwest National Laboratory, *Pacific Northwest GridWise Testbed Demonstration Projects Part I. Olympic Peninsula Project*, PNNL-17167, October 2007, pp. 3.1-3.15, available at http://www2.econ.iastate.edu/tesfatsi/OlympicPeninsulaProject.FinalReport_pnnl17167.pdf.

the absence of smart meters because they are set in advance and older meters are equipped to capture usage data at the appropriate level of detail.

Beyond the operational AMI benefits outlined above, when used in combination with TVR and enabling technologies, two additional classes of benefits can be realized:[321]

- **Customer benefits** arise from engagement in energy management driven by information and/or price signals, which leads to electricity usage reduction or load shifting and the opportunity to lower bills or mitigate cost increases. Moreover, with increased potential for demand response and direct load control, peak purchases can be reduced, thereby applying downward pressure on energy prices in spot markets, and offsetting the need for new generation and transmission and distribution (T&D) capacity.
- **Societal benefits** also arise from the integration of cleaner distributed generation and potentially from household usage reductions.

Among the benefits that the AMI roll-out can provide, peak load reduction is a main focus for utilities as it has the potential to reduce the need for transmission and distribution upgrades and new capacity and be included in their capacity planning for meeting future peak loads. A review of the impact of TVR with AMI over 122 studies that have tested different types of rate structures shows a wide range of results within each type of program as well as a clear trend across programs, as shown in Figure 65. The most commonly deployed TVR is time of use, which shows a range of 0–39% peak reduction. Variable Peak Pricing Programs demonstrate peak reductions ranging from 9% to 31%. Peak Time Rebates show improved impacts at the low end and similar high end impacts, ranging from 0–35%. Critical Peak Pricing (CPP) shows the highest average impact, but also the widest range—notably, 15 programs resulting in reductions of 30% or more.[322]

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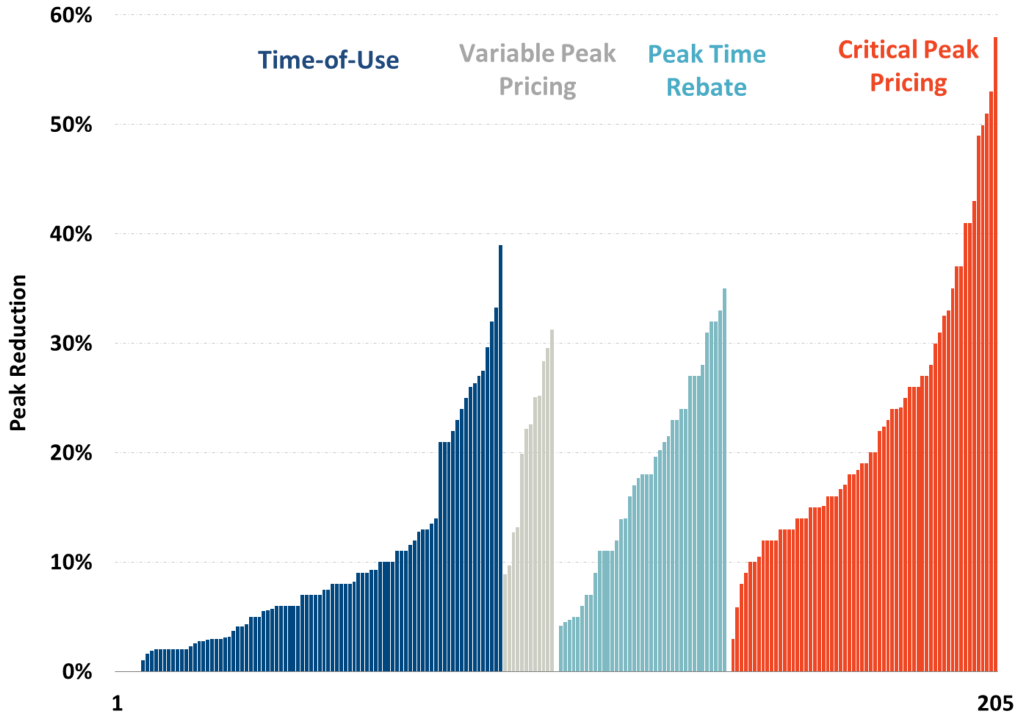
321 Faruqui, Ahmad, Lisa Wood, Adam Cooper, and Judith Schwartz, *The Costs and Benefits of Smart Meters for Residential Customers*, IEE Whitepaper, July 2011, available at http://www.edisonfoundation.net/iei/Documents/IEE_BenefitsofSmartMeters_Final.pdf.

322 Real-time pricing is less prevalent, although residential customers in Illinois can opt-in to such programs. See, *e.g.*, ComEd *op.cit.,* p. 4. The AEP Ohio gridSMART Demonstration Project is an example of several pilot projects that have also begun to assess potential benefits of residential real-time pricing programs. See AEP Ohio, *op.cit.,* pp.127–168. All data are current as of March 2015 and are obtained from The Brattle Group's Arcturus Database. See, for example Faruqui, Ahmad and Sergici, Sanem, Arcturus: International Evidence on Dynamic Pricing (July 1, 2013). Available at SSRN: http://ssrn.com/abstract=2288116.

Figure 65
Summary of Peak Reductions from Recent Time-Varying Rate Pricing Pilots

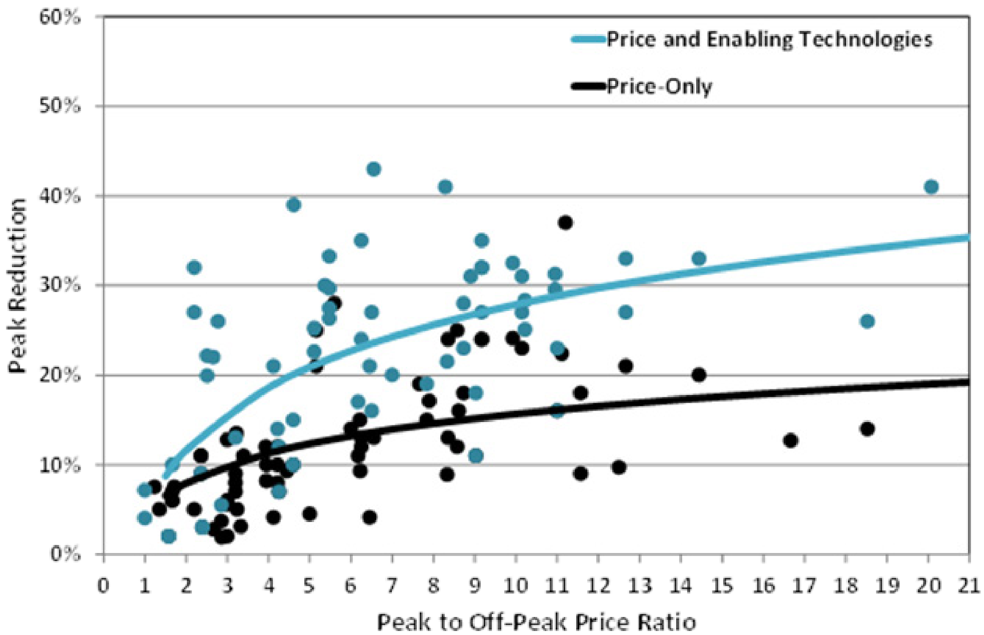


Source: All data are current as of March 2015 and are obtained from The Brattle Group's Arcturus Database. See, for example Faruqui, Ahmad and Sergici, Sanem, Arcturus: International Evidence on Dynamic Pricing (July 1, 2013). Available at SSRN: http://ssrn.com/abstract=2288116. The figure shows the distribution of impacts from 205 pricing pilots using Time of Use, Variable Peak Pricing, Peak Time Rebates, and Critical Peak Pricing rate structures.

Two potential factors in the range of peak reductions observed above are the ratio of peak and off-peak prices and the presence of enabling technologies, as shown in Figure 66. Each dot in Figure 66 represents a separate time-varying price study, with black dots corresponding to price-only programs, and blue dots corresponding to programs that also incorporate enabling technologies, such as smart thermostats or, in some cases, in-home information displays. The black and blue curves portray the fitted relationships for each type of study. In both cases, the greater the ratio of peak to off-peak prices, the more incentive consumers have for reducing their usage during the peak hours, as some portion of a peak load reduction is shifted to off-peak hours. Analysis of pilot studies show that although results differ significantly, a peak reduction of at least 10% would be expected without enabling technologies when peak-to-off-peak ratios are greater than 3. Adding in enabling technologies increases the expected reduction significantly, as the same 3× ratio will be expected to result in 16% reduction with the enabling technology installed. Several of the studies with the largest peak-to-off-peak differences in price saw impacts of greater than 30% when enabling technologies are also used. Figure 65 and Figure 66 provide indications of the potential peak reduction for programs instituted at a single utility.

In its most recent assessment of demand response and advanced metering, FERC estimated the demand response potential across 7 ISOs and RTOs to be 6% as of 2012.[323]

Figure 66
Impact of Prices Ratios and Enabling Technologies on Peak Reduction

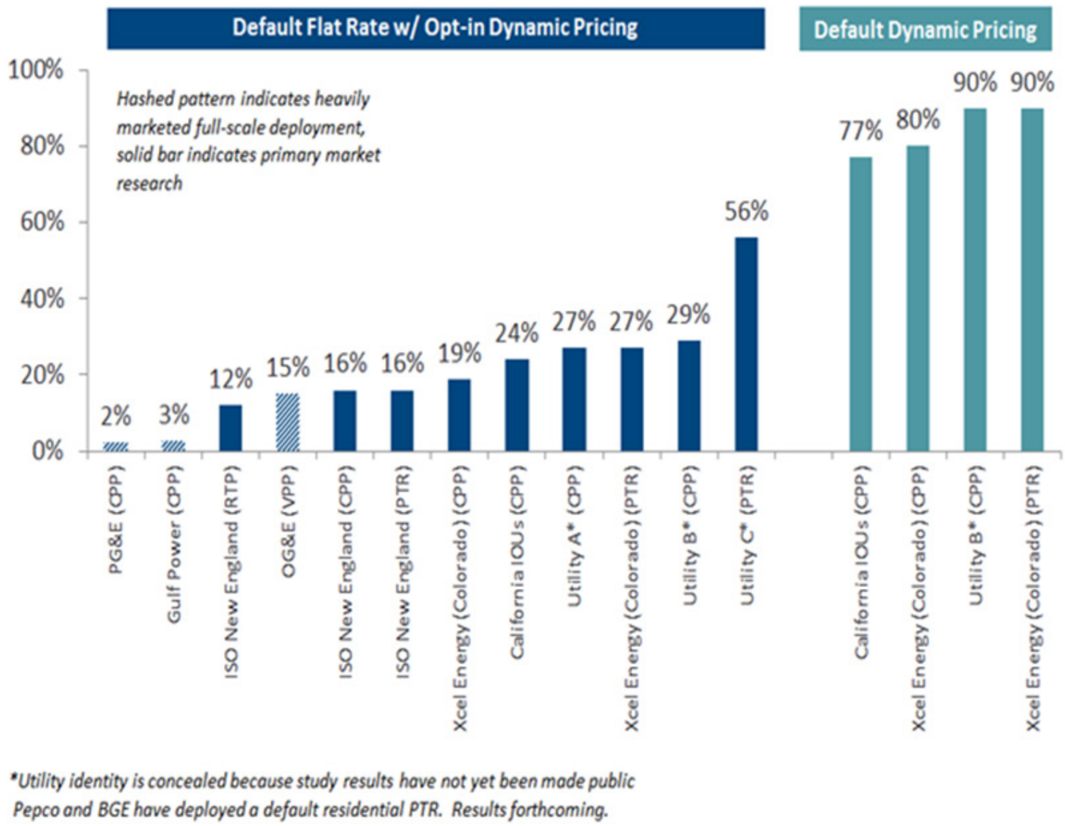


Source: Faruqui, Ahmad, Sanem Sergici, and Eric Shultz, The Arc of Price Responsiveness—Consistency of Results across Time-Varying Pricing Studies, IEPEC 2013, presentation forthcoming.

Currently the majority of time-varying rates are opt-in. Changing the default rate structure to TVR leads to this significantly increased participation, as shown in Figure 67.

323 FERC, Assessment of Demand Response and Advanced Metering, Staff Report, October 2013, available at http://www.ferc.gov/legal/staff-reports/2013/oct-demand-response.pdf, p. 11.

Figure 67
Residential Dynamic Pricing Enrollment Rates



Source: Faruqui, Ahmad, Ryan Hledik, and Neil Lessem, "Smart by Default," Public Utilities Fortnightly 152(8), August 2014, p. 28, online at http://www.fortnightly.com/fortnightly/2014/08/smart-default, p. 28.

While default TVR will reach a wider consumer base, opt-in consumers tend to be better educated about the programs; they are also often "first-adopters" who tend to be more active in the use of the technology. For that reason, the effectiveness of the smart meters and TVR will drop as programs shift from opt-in to default.[324] The greater usage rate tends to offset the impact of reduced average peak reduction, as shown in Table 14.

324 Faruqui, Ahmad, Ryan Hledik, and Neil Lessem, "Smart by Default," Public Utilities Fortnightly 152(8), August 2014, pp. 30-32, online at http://www.fortnightly.com/fortnightly/2014/08/smart-default; SMUD Smart Pricing Option Pilot, Interim Load Impact Evaluation, p. 153. Available at: https://www.smartgrid.gov/sites/default/files/MASTER_SMUD%20CBS%20Interim%20Evaluation_Final_SUBMITTED%20TO%20TAG%2020131023.pdf.

Table 14
Peak Reduction Under Opt-In TVR and Default TVR

	Time of Use		Critical Peak Pricing	
	Opt-In TVR	*Default TVR*	*Opt-In TVR*	*Default TVR*
Enrollment Rate	28%	85%	20%	84%
Average Peak Reduction Per Participant	6%	3%	18%	9%
Aggregate Peak Reduction (MW)	34	57	72	149

Source: Faruqui, Hledik, and Lessem 2014, p. 32.

D. Distributed Generation

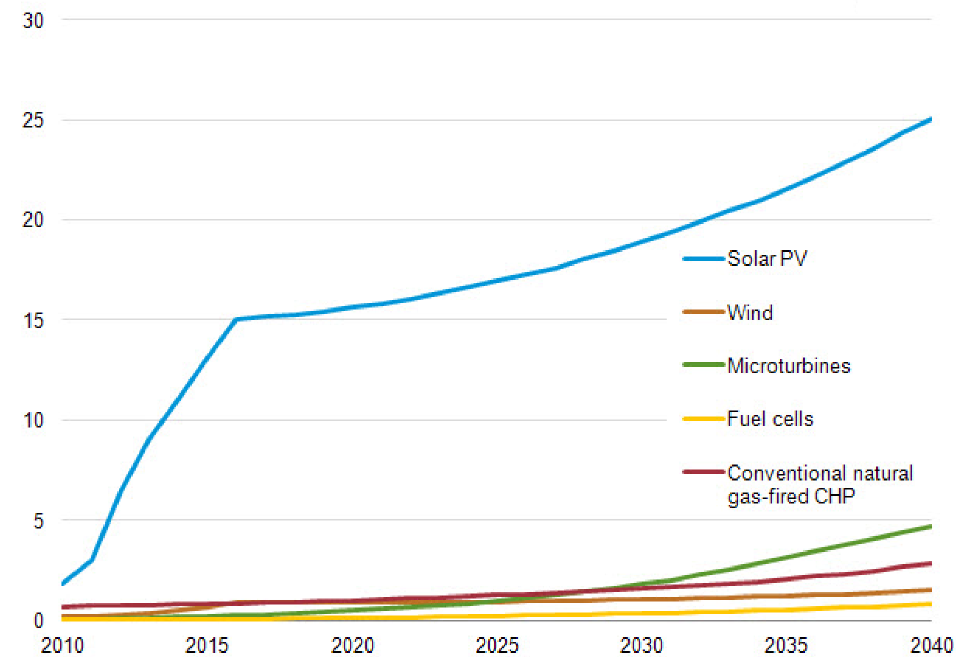
Distributed Generation (DG) refers to small-scale power generation technologies that are designed to meet *local* or *on-site load,* but that are typically connected to the distribution grid. While there is not a universally adopted definition for DG, the small size (most DG units have capacity below 20 MW) and on-site location of DG are key attributes of most definitions. There are many physical and contractual configurations for these technologies, including residential, commercial, community solar, microgrids, and customer-sited power purchase agreements (PPAs).

Common DG technologies include solar PV, combustion engines, microturbines, combined heat and power (CHP), micro hydro power, fuel cells and wind. While storage technologies are not a requirement, they can be used in conjunction with DG systems to improve the reliability or net cost of power. Although DG resources in the U.S. are not a new phenomenon, penetration is growing and generation mix is evolving as the economics of the distribution generation source improves and/or as driven by various state and federal policies.

Projections of distributed generation capacity additions, whether in the immediate or long-term future, are dominated by solar PV, with significant natural gas-fired additions (micro-turbines or CHP). This can be seen in Figure 68, or by examining the "End Use Generator" rows of Table 9 in the AEO2014 Reference Case.[325] The growth in residential and non-residential (*i.e.*, non-utility, distributed) solar PV installations in the past two years is consistent with these projections; the cumulative capacity has more than doubled in the past two years, as shown in Figure 69.

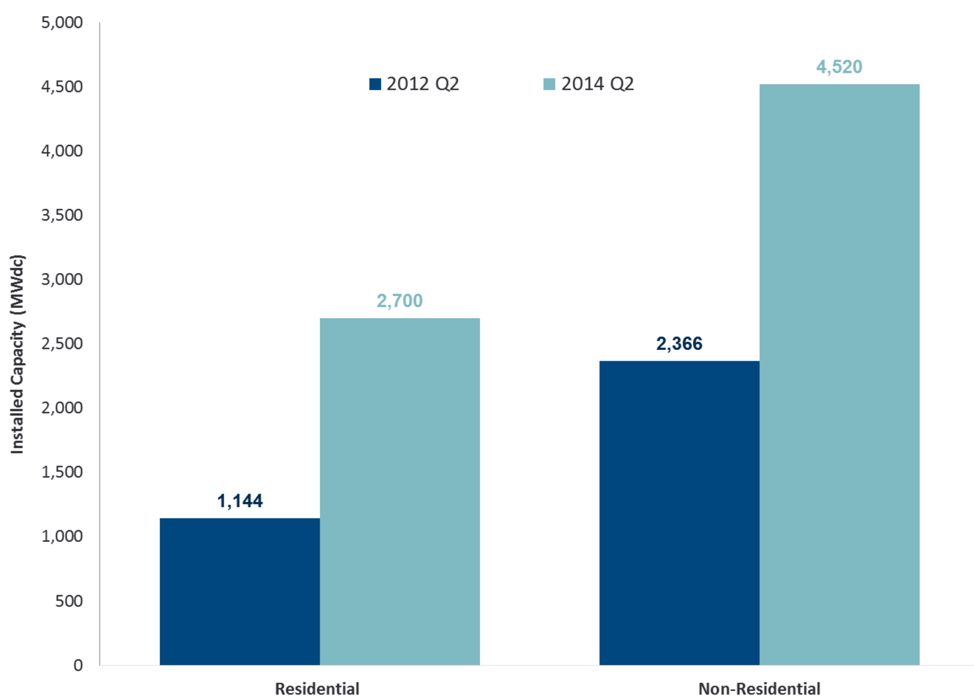
[325] Figure 68 measures "buildings sector DG capacity," while the end-use generating capacity presented in Table 9 of AEO2014 includes industrial-sited capacity that may be connected at the transmission level. However, by either definition, renewables (and particularly solar) are expected to account for much of the future increase in capacity. The AEO2014 tables can be found at http://www.eia.gov/forecasts/aeo/MT_electric.cfm

Figure 68
Installed Buildings Sector DG Capacity in AEO2013 Reference Case (Gigawatts)



Source: Energy Information Administration, *Modeling Distributed Generation in the Buildings Sectors*, August 2013, p. 2. Available online at http://www.eia.gov/forecasts/aeo/nems/2013/buildings/pdf/distribgen.pdf .

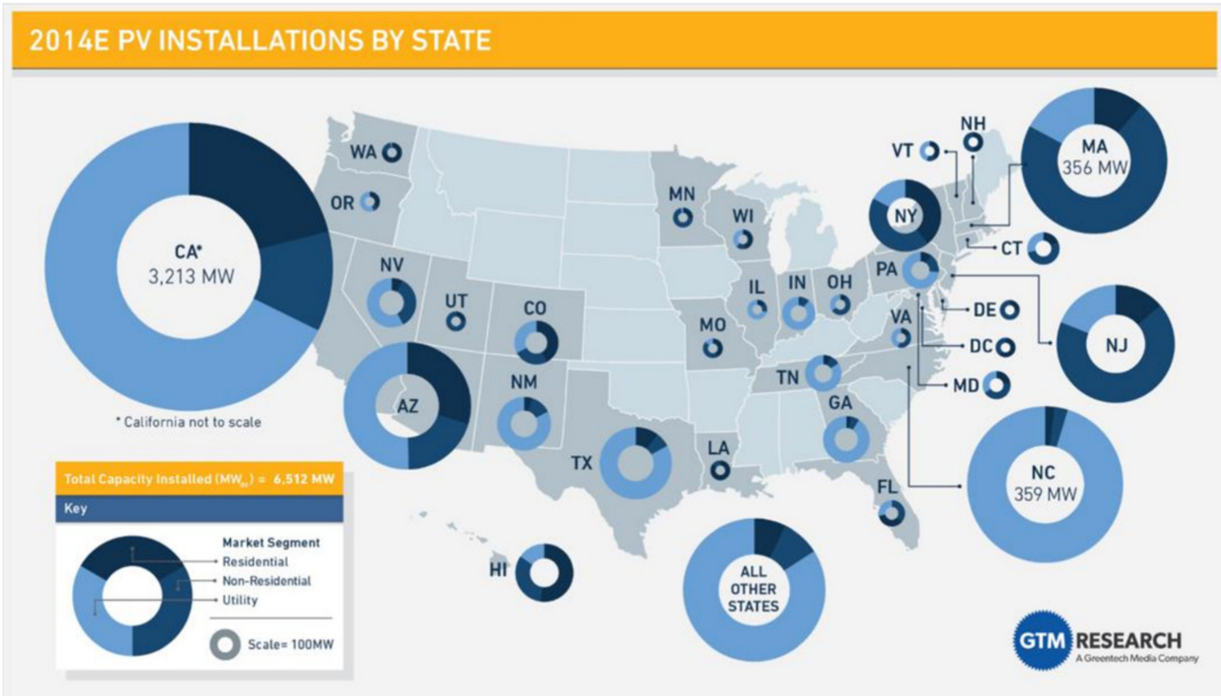
Figure 69
Cumulative Customer-sited Solar PV Capacity in 2012 and 2014



Source: Solar Energy Industries Association/Green Tech Media, U.S. Solar Market Insight Report Executive Summary, Q2 2014. Available at http://www.seia.org/research-resources/solar-market-insight-report-2014-q2

As might be expected, there is significant regional heterogeneity in the penetration of distributed PV capacity. While reliable data regarding cumulative solar PV installations is not publicly available, Figure 70 provides an estimate of the expected solar PV capacity increase, by state and segment, in 2014.

Figure 70
Estimated 2014 PV Installations by State



Source and notes: Solar Energy Industries Association/Green Tech Media, Solar Market Insight Report 2014 Q2. Available at http://www.seia.org/research-resources/solar-market-insight-report-2014-q2 The light blue portion of each circle represents utility solar installations. The darker portions represent residential and non-residential, respectively, both of which are very likely to be distributed generation.

Distributed generation provides a number of benefits to the electrical grid and society at large, but also poses some technical and economic challenges. Possible benefits include:[326]

- Avoided energy costs of the marginal resource that is displaced by the DG resource;
- The cost of central generation capacity that can be deferred or avoided;
- Avoided system losses from power that no longer needs to be delivered over the transmission and distribution system;
- The cost of avoiding T&D upgrades or expansions when DG can meet rising demand locally;
- Reduced congestion along the T&D network;

326 Rocky Mountain Institute, Electricity Innovation Lab, *A Review of Solar PV Benefit & Cost Studies*, 2nd Edition, pp. 13–17.

- The reduction of the effects of large-scale outages that come from a more dispersed and diverse generation base;
- The provision of back-up power sources from DG facilities; and
- Depending on the DG technology, a variety of potential environmental benefits, including avoided emissions of carbon and other pollutants and decreased land footprint required for energy generation.

These benefits are difficult to quantify and will vary immensely with the characteristics of the existing infrastructure and other location-specific factors, and will also change with DG penetration levels.[327] Technical and economic challenges include substantial grid design and operational hurdles and threats to the existing utility business model, both of which will be discussed in more detail below.

1. Net Metering Regulations

Net metering is a utility rate policy under which a customer with a distributed generator is paid or credited for their production, at the full delivered retail power rate that the customer pays for all non-self-generated supplies. More than 40 states and the District of Columbia have established net-metering policies.[328] These policies vary along several dimensions, including limits on individual system capacity, limits on overall program capacity, treatment of "rollover" credits (when a customer generates more electricity than they consume in a month), and the property rights to the renewable energy certificates produced by solar panels or distributed wind installations.[329] Net metering has been extremely successful in driving DG investment; in some areas DG penetration is becoming significant. For example, as of the end of 2013, 1 in 9 homes in Hawaii have installed solar panels.[330] Figure 70 highlights those states with significant PV capacity additions in 2014.

Critics of net metering policies have argued that they do not provide an accurate representation of the value of distributed generation, in that utility customers with distributed generation nonetheless are beneficiaries of grid services provided by their access to the central utility's grid. These services include regulation (balance of supply and demand in sub-second intervals to maintain a stable frequency), the ability to resell energy during hours of excess generation, back up service when DG resources become unavailable, and voltage and frequency control services.[331]

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327 The Rocky Mountain Institute has performed a meta-analysis of the various costs and benefits associated with these categories. See *op. cit.* pp. 23–42.

328 DSIRESolar, Net Metering, Database of State Incentives for Renewables & Efficiency, online at http://www.dsireusa.org/solar/solarpolicyguide/?id=17; Freeing the Grid, Best Practices in State Net Metering Policies and Interconnection Procedures, online at http://freeingthegrid.org/

329 DSIRE, *op. cit.* Also see Freeing the Grid, *op. cit*.

330 Solar Energy Industry Association, 2013 Top 10 Solar States, online at http://www.seia.org/research-resources/2013-top-10-solar-states.

331 IEE, *Value of The Grid to DG Customers*, IEE Issue Brief, Updated October 2013, p.2.

The utility's ability to provide these grid services results from large capital investments, and cost recovery for those investments is built into retail rates. When DG customers receive net metering credit, it is typically at the full retail rate. Consequently, according to this argument, DG customers are over-compensated for their generation, leading to more installation of DG capacity than is efficient. Furthermore, some have argued that to the extent that DG customers are not paying a fair share of the cost of the grid, this increases the costs to non-DG customers, effectively subsidizing PV owners at the expense of those who cannot afford PV.[332]

However, others have argued that the benefits provided by distributed generation (and in particular, solar PV) capacity are not fully captured by the wholesale rate either. In addition to the avoided energy costs (often during peak hours), other benefits include: reductions in system losses created when centrally-generated power is distributed over the transmission and distribution system; avoided investment costs in generation, transmission, and distribution capacity; the inherent fuel price hedge provided by fuel-free generation; and a variety of environmental benefits, including avoided emissions of carbon and other pollutants and decreased land footprint required for energy generation.[333]

Net metering may evolve, as other models for compensating DG owners are developed. As the grid evolves to become more characterized by active consumers and two-way power flows (discussed in further detail below), many stakeholders are not only considering new technology requirements but also policy and business model changes need to better manage the future grid.[334] New grid services will need to be priced and the existing systems for valuing and compensating DG power may need to be redesigned as well. Arizona, California, Massachusetts, Nevada, and Oklahoma have all undertaken steps to adjust their rate treatment of this resource.[335]

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332 *Id.*, pp. 4-5.

333 Rocky Mountain Institute, *op. cit.*, pp. 13-17.

334 New Business Models for the Distributed Edge: The Transition from Value Chain to Value Constellation, 2013: http://www.rmi.org/New_Business_Models_Download.

335 See E-01345A-13-0248: "In the matter of the application of Arizona Public Service Company for approval of net metering cost shift solution," Arizona Corporation Commission, July 12, 2013; "Commission Decision (D.) 12-05-036: Order Instituting Rulemaking Regarding Policies, Procedures and Rules for the California Solar Initiative, the Self-Generation Incentive Program and Other Distributed Generation Issues," California Public Utility Commission, May 24, 2012; "D.P.U. 14-04-B Investigation by the Department of Public Utilities upon its own Motion into Time Varying Rates," June 12, 2014; "PUCN Docket No. 13-07010: Investigation to Examine the Costs and Benefits of Net Metering in Nevada Pursuant to Section 26.5 of Assembly Bill 428 (2013)," Public Utility Commission of Nevada, July 8, 2013; and "Senate Bill 1456: An Act relating to public utilities; amending 17 O.S. 2011, Section 156, which relates to distributed generation costs; defining terms; modifying prohibition relating to recovery of certain fixed costs from electric customers utilizing certain distributed generation; prohibiting subsidization of certain costs among customer class; requiring rate tariff adjustment by certain date; and providing an effective date," Oklahoma State Senate, April 2014.

2. Solar Costs and Business Model Innovations

During the first half of 2014 alone, over half a million homeowners and commercial customers have installed solar PV; the total non-utility scale operating PV capacity in the U.S. is now greater than 7 GW DC.[336] Rapid expansion of solar resources has been tied to the 64% decline in the average price of a solar panel since 2010.[337] Recent decreases in the cost of solar have stemmed from reductions in global prices for solar modules. Over the longer term, price declines have come from non-module costs including inverters, mounting hardware, labor, permitting and fees, customer acquisition, overhead, taxes, and installer profit.[338]

Aside from costs, innovations in financing and business models for distributed solar have driven development, particularly in the residential sector. In particular, the advent and spread of third-party ownership (TPO) has been key to the rapid growth in solar over the past several years. Under this model, homeowners contract with a third-party company who continues to own the installation and is responsible for financing, permitting, designing, installing, and in some cases, maintaining the PV system.[339] The homeowner then either purchases the solar electricity through a power purchase agreement (PPA) or makes monthly lease payments to the solar company; net metering provides the homeowner with a revenue stream from the utility, either directly or through the third-party company. The TPO model allows the homeowner to avoid the upfront capital costs, and to avoid having to become knowledgeable about the purchase, installation, or maintenance of the system. Figure 71 illustrates the importance of third-party ownership to the growth of residential solar PV capacity in California.

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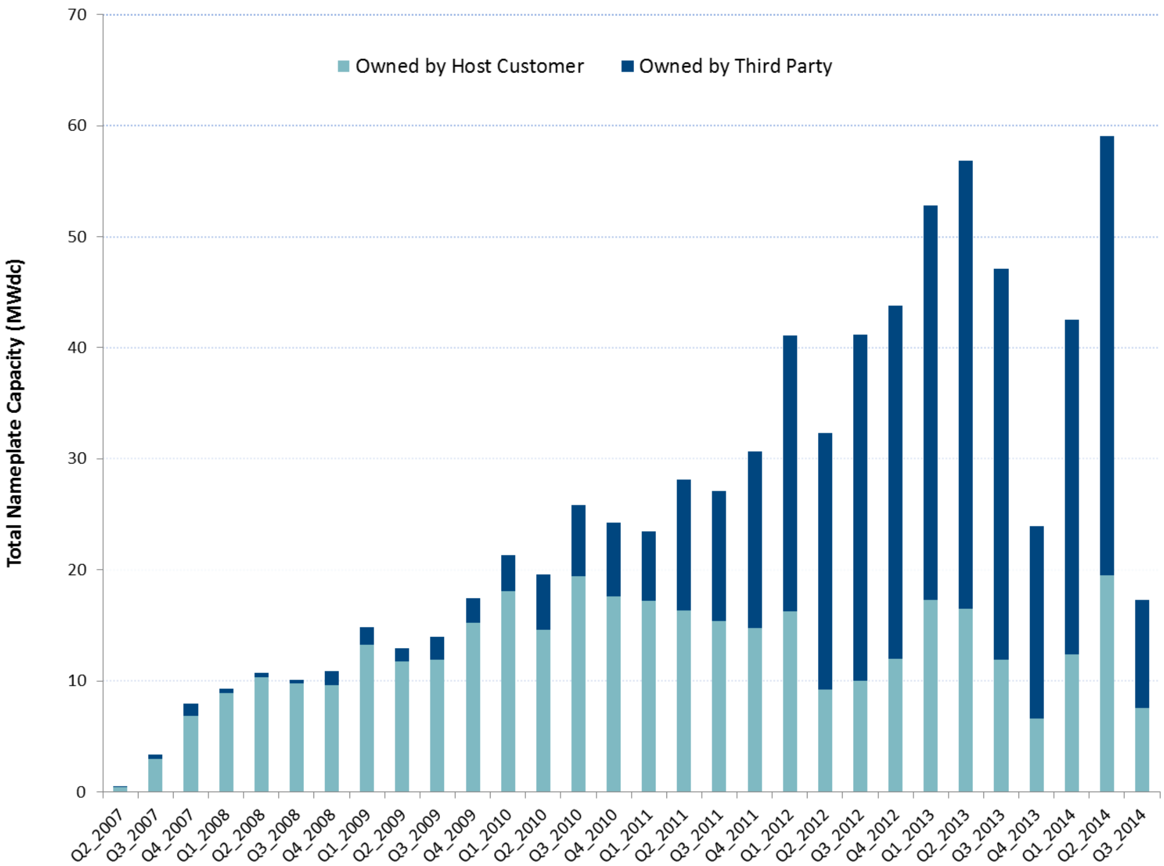
336 The Solar Energy Industry Association, "U.S. Solar Market Insight: Executive Summary," Q2 2014, p. 12. Note that Solar PV capacity can be measure in direct current (DC) or alternating current (AC) terms, and the two are not equivalent. A basic rule of thumb is that after conversion, the AC capacity is 75–80% of the DC capacity.

337 Solar Energy Industries Association, Solar Energy Facts: Q2 2014, Over half a million solar installations now online in U.S., online at http://www.seia.org/sites/default/files/Q2%202014%20SMI%20Fact%20Sheet_0.pdf.

338 Barbose, Galen, Naïm Darghouth, Samantha Weaver, and Ryan Wiser, *Tracking the Sun VI: An Historical Summary of the Installed Price of Photovoltaics in the United States from 1998 to 2012*, SunShot U.S. Department of Energy, Lawrence Berkeley National Laboratory, LBNL-6350E, July 2013, available at http://emp.lbl.gov/sites/all/files/lbnl-6350e.pdf.

339 U.S. Energy Information Administration, Today in Energy, Most new residential solar PV projects in California program are not owned by homeowners, September 17, 2013, online at http://www.eia.gov/todayinenergy/detail.cfm?id=12991.

Figure 71
California Residential Solar PV Capacity Additions by Quarter



Source: Go Solar California, Welcome to California Solar Statistics, online at http://californiasolarstatistics.ca.gov/.

Third-party ownership is also an important factor in other states; for example 56% of the residential PV installations in Massachusetts during the second quarter of 2014 used a TPO model, as did 90% of those in Colorado. However, as solar costs decrease, the TPO model may become less crucial.[340]

Another model that has facilitated solar PV capacity addition in some areas is known as a community solar garden, in which a larger PV array is collectively owned by several subscribers who each receive net-metering credits from their utility on their electric bill.[341] This has also been called virtual net-metering, but is only available in a limited number of states.

3. Other: Distributed Wind, Gas Turbines, CHP

While Solar PV is leading DG development, there are still sizable amounts of other DG resources on the grid today.

340 Solar Energy Industry Association, U.S. Solar Market Insight: Executive Summary, Q2 2014, p. 8.

341 Solar Gardens, Frequently Asked Questions, online at http://www.solargardens.org/frequently-asked-questions/

Between 2003 and 2013, 842 MW of distributed wind units were installed in the U.S., reflecting nearly 72,000 units. However, 2013 saw the lowest capacity addition of DW (30 MW) since 2005, due in part to the expiration of various incentive programs and advantages of solar PV (better financing, lower prices, easier siting, and technology-specific incentives). The American Wind Energy Association estimated that up to 130 MW of DW was under construction at the end of 2013.[342] As Figure 68 indicates, growth of distributed wind is expected to be modest.

Combined Heat and Power (CHP), which uses the waste heat generated in producing power for secondary on-site purposes, is another DG technology that is poised for growth in the next few years.[343] The majority of CHP capacity is located at industrial manufacturing facilities, much of which will be directly connected to the transmission system (thus forgoing the distribution system). However, an increasing share of the new CHP capacity is at commercial and institutional facilities, particularly with the expected sustained low prices of natural gas driving favorable economics.

Portable small-scale generators are also poised for future growth in response to recent severe storms that have caused outages. Using small generators as back up (redundant equipment) is gaining in popularity among customers and could be pursued as a community or utility level initiative. Recent research suggests that for a city of 100,000 customers, a regulated utility could maintain a fleet of mobile generators with sufficient capacity to power critical facilities—including police stations, grocery stores, gas stations, and schools—for as little as $8 a year per customer.[344]

In the longer-term, microturbines are also expected to become a more significant share of distributed generation capacity. However, the bulk of this growth is projected to occur after 2020, as shown in Figure 68.[345]

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342 The distributed wind resources being described come in various sizes but are generally comprised of units with capacity of 100 kW or less. Pacific Northwest National Laboratory/U.S. Department of Energy, *2013 Distributed Wind Market Report*, PNNL-23484, August 2014, available at: http://energy.gov/sites/prod/files/2014/09/f18/2013%20Distributed%20Wind%20Market%20Report.pdf.

343 Hampson, Anne and Jessica Rackley, *From Threat to Asset—How Combined Heat and Power (CHP) Can Benefit Utilities*, ICF International, July 23, 2014, download available at http://www.icfi.com/insights/white-papers/2014/how-chp-can-benefit-utilities.

344 Zarakas, William, Frank Graves, and Sanem Sergici, "Low Tech Resilience," *Public Utilities Fortnightly* 151(9), September 2013, online at http://www.fortnightly.com/fortnightly/2013/09/low-tech-resilience.

345 Energy Information Administration, Modeling Distributed Generation in the Buildings Sectors, August 2013, p. 2. Available at: http://www.eia.gov/forecasts/aeo/nems/2013/buildings/pdf/distribgen.pdf

4. Impact of Two-Way Flow

The combination of increased DG (especially solar PV) penetration and an existing distribution grid that is designed primarily for one-way radial flows of power to customers is expected to pose operational challenges to utility engineers responsible for the delivery of power to consumers. At levels of DG penetration currently observed in most parts of the country, DG simply looks like a load reduction from the standpoint of the system operator. However, on distribution circuits with higher levels of penetration, DG can lead to a host of operational issues. These include, but are not limited to the following:

- Voltage increases that can result in damage to customer and utility equipment;
- Rapid voltage variability (for example when conditions change from sunny to cloudy or vice-versa) that can result in flickering and other issues; and
- Reverse power flows (where power flows towards, rather than away from, a distribution transformer) that can also damage voltage control and regulation equipment.[346]

Some utilities are already encountering these types of issues. On the island of Oahu, 20% of the distribution-level circuits owned and operated by Hawaii Electric (HECO) have rooftop PV capacity that exceeds 100% of daytime minimum load (DML) (as of February 2014). At this threshold, many of the operational issues begin to be real risks; HECO has had to slow the pace of new net metering connections on those circuits as interconnection studies need to be performed and safety measures need to be implemented. Another 20% of the circuits on Oahu have rooftop PV capacity exceeding 75% of DML, while 10% of the circuits on the island of Hawaii have also reached 100% of DML; until and unless the distribution grid is modernized this may eventually mean that PV expansion is further limited.[347] While Hawaii's circumstances are somewhat unique, with its island grid and high electricity prices, San Diego Gas & Electric (SDG&E) is beginning to experience some of these operational issues as well. Across the SDG&E service area, solar DG capacity was 5.9% of peak load as of July 2014 and is expected to double by the end of 2015; SDG&E has reported a "host of operational issues."[348]

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[346] Wesoff, Eric, "How Much Solar Can HECO and Oahu's Grid Really Handle?," *Greentech Media*, February 10, 2014, online at http://www.greentechmedia.com/articles/read/How-Much-Solar-Can-HECO-and-Oahus-Grid-Really-Handle; IEEE Joint Task For on Quadrennial Energy Review, *IEEE Report to DOE QER on Priority Issues*, prepared for William F. Hederman, Senior Advisor to the Secretary, U.S. Department of Energy, September 5, 2014, available at http://www.ieee-pes.org/images/pdf/IEEE%20QER%20Report%20September%205%202014%20HQ.pdf. Note that voltage variability is a function of the intermittency of renewable generation; this may be less of an issue if the DG on a given circuit is all CHP technology. Voltage variability in utility-scale solar also poses technical issues, though not at the level of the distribution grid.

[347] Wesoff, *op.cit.*

[348] Savenije, Davide, "How SDG&E is Dealing with High Penetrations of Rooftop Solar: San Diego Gas & Electric has 5.9% rooftop solar in its territory—a figure that's set to double by the end of next year."

Continued on next page

The technical solutions to these operational issues vary in complexity and cost and depend on the level of distributed PV penetration. In some cases, conventional solutions focused mostly on the reconfiguration of feeder systems and operation modes of voltage control will be adequate, while in others, advanced smart grid solutions with new grid architectures and new technology are required. In short, there is uncertainty with the cost levels needed to accommodate large penetration of distributed PV and other DG.[349] This issue is complicated by the need to develop solutions that are flexible enough to be used across a variety of feeder structures, from short urban feeders to longer rural feeders.[350] The issue of who bears these costs is also creating tensions—utilities are likely to bear the significant costs of distribution grid upgrades, despite the inherent lack of control over the decisions that are making those upgrades a necessity.

E. Plug-In Electric Vehicles

Plug-in electric vehicles (PEVs) represent a new source of load on the distribution grid not envisioned when the current grid was designed. Sales of modern PEVs, which today include plug-in hybrids, extended range EVs, and battery-only EVs, have seen rapid growth since their introduction but are still at low penetration levels. As of September 2014 there are more than 255,000 PEVs on U.S. roads, although that still represents roughly one-tenth of one percent of all registered vehicles.[351] In his 2011 State of the Union address, President Obama set a goal of 1 million EVs on the road by 2015.[352] Although given the current total sales of electric vehicles, this goal will not be met; one widely-cited projection estimates that there could be more than 2.7 million PEVs on the road by 2023.[353]

While these levels of PEV penetration will not pose significant challenges to the existing generation and transmission infrastructures, there are potentially significant operational issues at the distribution level, especially in older neighborhoods that may be approaching the capacity

Continued from previous page

Utility Dive, July 25, 2014, online at http://www.utilitydive.com/news/how-sdge-is-dealing-with-high-penetrations-of-rooftop-solar/290227/.

349 IEEE, *Report to DOE QER on Priority Issues*, *op. cit.*

350 GTM Research, "Grid Edge—Utility Modernization in the Age of Distributed Generation," October 2013, p. 40.

351 Electric Drive Transportation Association, Electric Drive Sales Dashboard, online at http://www.electricdrive.org/index.php?ht=d/sp/i/20952/pid/20952; U.S. Department of Transportation, Research and Innovative Technology Administration, Bureau of Transportation Statistics, Table1-11: Number of U.S. Aircraft, Vehicles, Vessels, and other Conveyances, online at http://www.rita.dot.gov/bts/sites/rita.dot.gov.bts/files/publications/national_transportation_statistics/html/table_01_11.html.

352 The White House, Office of the Press Secretary, Remarks by the President in State of Union Address, January 25, 2011, online at http://www.whitehouse.gov/the-press-office/2011/01/25/remarks-president-state-union-address.

353 Navigant Research, Plug-In Electric Vehicles on Roads in the United States Will Surpass 2.7 Million by 2023, Press Release, April 28, 2014, online at http://www.navigantresearch.com/newsroom/plug-in-electric-vehicles-on-roads-in-the-united-states-will-surpass-2-7-million-by-2023.

limits of the local distribution network. The experience with PEV integration in the Sacramento Municipal Utility District (SMUD) showed that the 2nd to 4th PEV connected to a transformer tended to cause problems, and that upgrades to that transformer and/or circuit when the second vehicle was added cost SMUD roughly $1,300. Managing charging loads, in a process similar to managing the loads of water heaters, should defer system impacts for a significant period of time.[354]

Most vehicles are idle for the majority of the day; accordingly PEVs may, with advances in battery technology, also provide some storage and grid ancillary services.[355] Peak shaving and demand response may also be an option, although high levels of PEV penetration could also contribute to the reverse flow issues from DG, as described above.

F. Implications for Utilities

It is feared that the combination of pressures on the distribution grid could lead to what some have called a "downward spiral" or the "utility death spiral."[356] This threat is borne out of the combination of flat to declining utility sales and existing utility business models, which depend on volumetric rates to recover the fixed costs of building and maintaining suitable infrastructure. As these various forces, including distributed generation, energy efficiency, and other factors discussed above, exert downward pressure on utility sales, the most obvious utility and regulator response is to increase volumetric rates, as the same level of fixed costs needs to be recovered despite the decrease in sales. This only exacerbates the trend, as the increase in rates further incentivizes consumers to either install distributed generation (especially in states with net metering policies) or to pursue additional energy efficiency measures, further depressing sales. Figure 72 below illustrates the threat diagrammatically.

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354 *IEEE Report to DOE QER on Priority Issues*, *op. cit.*, pp. 38–41. In conjunction with some of the "smart grid" technologies discussed above, PEVs could also use "smart charging," in which they automatically charge when prices are low. This would also mitigate system impacts, to the extent that PEV users are flexible with respect to charging times.

355 Han, Sekyung, and Soohee Han "Economic Feasibility of V2G Frequency Regulation in Consideration of Battery Wear," *Energies 2013* 6(2), February 6, 2013: 748–765, available at http://www.mdpi.com/1996-1073/6/2/748; Noel, Land and Regina McCormack, "A cost benefit analysis of a V2G-capable electric school bus compared to a traditional diesel school bus," *Applied Energy* 126, August 1, 2014: 246–265, available at

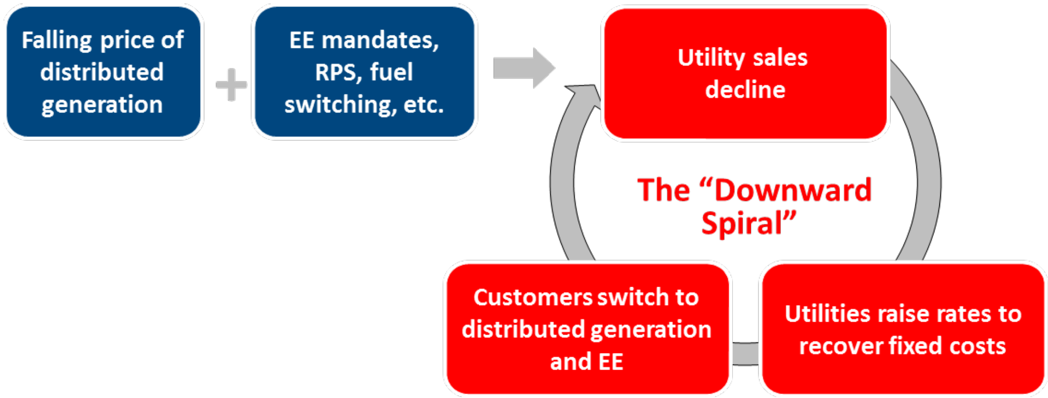
http://www.sciencedirect.com/science/article/pii/S0306261914003420.

356 Denning, Liam, "Lights Flicker for Utilities." *The Wall Street Journal,* December 22, 2013, online at http://online.wsj.com/articles/SB10001424052702304773104579270362739732266.

See also Felder, Frank A. and Rasika Athawale, "The Life and Death of the Utility Death Spiral." *The Electricity Journal* 27(6), July 2014, available at

http://www.sciencedirect.com/science/article/pii/S1040619014001407.

Figure 72
Illustration of the "Downward Spiral"



Source: Ryan Hledik, "Residential Demand Charges: A Rate Design Revolution?" Presented at Center for Research in Regulated Industries 27th Annual Western Conference June 25–27, 2014, Monterey California, June 26, 2014.

Financial analysts have also recognized these risks. While bond ratings, which affect the cost of capital faced by utilities, have not yet been affected, some analysts have lowered their view on the utility sector, specifically citing risks from distributed solar generation.[357]

While the downward spiral threat is not strictly a distribution-level issue, as it will also result in pressure on generation and transmission infrastructure for many utilities, it arises in part out of the increase in distributed generation. It is potentially further exacerbated by distribution-level trends. For example, the need for resiliency improvements in response to an increased threat of disruptions from external causes disrupting the distribution grid increases the investment needs, relative to a business-as-usual scenario. The increased penetration of distributed generation also has a second effect: not only does it further decrease utility sales, but to the extent that it results in operational issues as discussed above, it again increases costs and investment requirements as equipment needs to be upgraded and distribution circuits and transformers need to be reconfigured.[358] Thus, a more complete representation of the "downward spiral" might include additional boxes, as portrayed in Figure 73.

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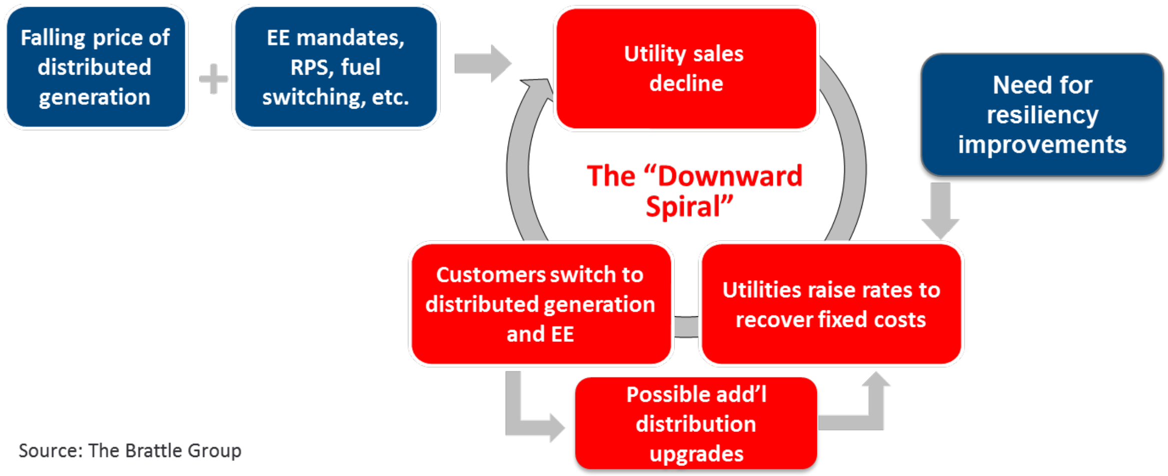
[357] See, *e.g.*, Aneiro, Michael, "Barclays Downgrades Electric Utility Bonds, Sees Viable Solar Competition," *Barrons.com*, May 23, 2014, online at: http://blogs.barrons.com/incomeinvesting/2014/05/23/barclays-downgrades-electric-utility-bonds-sees-viable-solar-competition/; Sweeney, Darren, "In downgrade, Barclays sees electric sector at risk of 'solar vortex,'" *SNL Interactive*, May 28, 2014, online at: https://www.snl.com/InteractiveX/Article.aspx?cdid=A-28226048-12590; Sweeney, Darren, "Duke, SCANA among handful of utilities Bernstein sees at risk from distributed solar," *SNL Interactive*, May 22, 2014, online at https://www.snl.com/InteractiveX/Article.aspx?cdid=A-28175506-14118.

[358] Interestingly, to the extent that the grid is not upgraded to accommodate additional levels of DG, it could place a natural floor on the "downward spiral." However, such an approach would preclude utilities and consumers from a wide variety of benefits from DG, as outlined above, which may far outweigh the costs of upgrading.

Figure 73
Updated Illustration of the "Downward Spiral"



Source: The Brattle Group

In addition to the threat to utilities, this cycle would have negative implications for most consumers as well. Consumers who do not have the means to invest in energy efficient appliances or rooftop solar panels would likely end up paying higher rates for electricity, and as discussed above, even if innovative business models allowed all consumers to access solar or DG, the distribution grid is not generally equipped to accommodate such high levels of penetration. If rate increases deter regulators from allowing necessary grid upgrades, all customers could suffer from deterioration in grid services and reliability.[359]

There is an emerging consensus that a resolution to this set of tensions will have to involve some sort of rate re-design.[360] One option is to increase the fixed component of customer bills and decrease the volumetric component by a corresponding amount. Such a structure would be more reflective of the actual cost structure, a greater portion of which is fixed than is suggested by the current prevailing rate structures. For example, EPRI estimates that fixed costs providing grid support are roughly $51 per residential customer per month, out of an average total bill of $110.[361] There has been some recent movement towards increased fixed charges, as evidenced by Sierra Pacific increasing its basic service charge (from $9.25/month to $17.50/month) as of January 1, 2014.[362] However, critics argue that this approach penalizes PV owners, decreases

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359 See, for example, Hledik, Ryan, "Rediscovering Residential Demand Charges," *The Electricity Journal* 27(7), August/September 2014 ("Hledik Aug/Sep 2014"), available at http://www.sciencedirect.com/science/article/pii/S104061901400150X.

360 See, for example, Hledik Aug/Sep 2014; and Felder and Athwale, *op.cit.*

361 Electric Power Research Institute, *The Integrated Grid: Realizing the Full Value of Central and Distributed Energy Resources*, 30020022733, February 2014, p. 22, download available at http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002002733&Mode=download.

362 Stanfield, Jeff, "Basic Service Charge for Many Sierra Pacific Power Customers to Nearly Double Jan. 1," *SNL Interactive,* December 17, 2013, available at:

Continued on next page

incentives for energy efficiency, and shifts too much of the cost burden to lower-consumption (and possibly lower-income) customers.[363]

Another residential rate design that has garnered increased attention is a structure containing residential demand charges. This type of structure, under which a portion of the bill is determined by the peak hourly demand during a month (or alternatively, each customer's demand during the system's peak hours of demand) is already common in tariffs for large commercial and industrial customers, and may become an increasingly common option with the rollout of smart meters. The use of demand charges in place of increasing fixed charges may avoid many of the concerns with larger fixed fees, and offers additional benefits in the form of peak shaving, as customers are incentivized to be more aware of their consumption during peak hours.[364]

The question of the right rate design will vary across utilities, as the forces that are necessitating a re-examining of rate design (increased DG penetration, increased need for resilience investments, the need for a modern grid, and the rate of load growth) vary widely across utility service territories. Ultimately, the decision-making process should seek to take into account both the full value of distributed generation and the full value of grid services, while ensuring grid reliability and financial health of the utilities. There will be few easy choices.

Continued from previous page

https://www.snl.com/InteractiveX/ArticleAbstract.aspx?id=26308183.

363 See for example, Ivey, Mike, "Wisconsin Utilities Lead in Seeking Hikes in Monthly Charges," *The Capital Times*, August 15, 2014, online at http://host.madison.com/news/local/writers/mike_ivey/wisconsin-utilities-lead-in-seeking-hikes-in-monthly-charges/article_9f109eee-23b9-11e4-9307-0019bb2963f4.html; Cummings, Bill, "Opposition emerges to CL&P's proposed increase in fixed fees," *ctpost.com*, August 26, 2014, online at http://www.ctpost.com/news/article/Opposition-emerges-to-CL-P-s-proposed-increase-5714758.php; and Kaufmann, K., "Utilities Seek Electric Rate Increases," *The Desert Sun*, April 22, 2014, online at http://www.desertsun.com/story/money/business/2014/04/22/rooftop-solar-southern-california-edison-utilities-seek-electric-rate-increases/7995093/.

364 Hledik Aug/Sep 2014.

IV. Storage

A. Introduction

Unlike liquid fuels and natural gas systems, the electricity system must maintain an almost instantaneous balance between production and consumption. However, electricity demand is constantly changing minute by minute and varies considerably throughout a single day, across seasons, and over years. These physical realities and requirements of balancing electric power production with consumption create engineering challenges for maintaining a reliable and economically efficient system. The electric power system as a whole has been built and designed to overcome these challenges through a range of technologies, operating procedures, and planning processes.

Bulk electric energy cannot be efficiently stored with known technology for longer than a few milliseconds as electrical energy.[365] Instead, electric energy must first be converted into another energy form, such as kinetic (*e.g.*, flywheels), potential (*e.g.*, pumped hydro storage), chemical energy (*e.g.*, batteries), or thermal energy, and then reconverted back into electricity. The conversion and reconversion process can be both technically challenging and inefficient, which can also make energy storage relatively expensive. In addition, the most common form of storage on the electric system today, pumped hydro storage, is limited to areas with the required water supply and typography to efficiently pump and store water.

Today energy storage is a relatively small part of the electricity system. As of August 2014, the total installed capability for storage is 23.4 GW in 324 projects, which is only about 2% of the total installed electric generating capacity.[366] Of this amount, 96% is pumped hydro storage. Currently storage systems operate primarily in the form of peak shaving for energy arbitrage and provide some ancillary services. Going forward, with newer storage technologies that have technical characteristics distinct from those of pumped storage, energy storage may have the potential to address some new challenges, especially if the costs of energy storage come down significantly. In addition, many of the energy storage systems now being deployed have capabilities different from pumped hydro storage, and are being built in response to market opportunities and regulatory mandates.

This chapter provides an overview of these technologies, including their capacity and capability, the roles they do and may play in the future, and their cost effectiveness. This chapter does not discuss in depth the technical capability of technologies, but is intended to provide context for understanding how (and how much) storage participates in the market, what opportunities it

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365 Capacitors store electrical energy in limited quantities, and capacitors installed at substations are important for maintaining system reliability. Due to the nature of capacitors however, they are most valuable to the system in applications that require high power output, rapidly charging and discharging, such as maintaining system frequency and responding to short-term disruptions in capacity.

366 DOE, DOE Global Energy Storage Database, online at http://www.energystorageexchange.org/

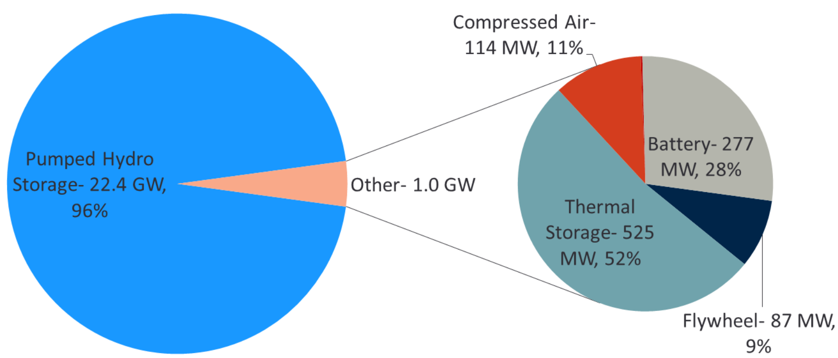
may have in the future, and what market and regulatory barriers exist to storage being able to provide its full economic value.

B. Capacity and Capability of Storage Technologies

1. Overall Existing and In-Development Capacity

Pumped storage accounts for 96% of the storage capacity with other technologies such as compressed air energy storage (CAES), thermal energy storage, batteries, and flywheels constituting the remaining 4% of overall storage capability, as shown in Figure 74.

Figure 74
Existing Storage Installations by Rated Power



Source: U.S. Department of Energy, DOE Global Energy Storage Database, online at http://www.energystorageexchange.org/

The capacity of pumped hydro storage facilities is normally larger than the other technologies. As shown in Table 15, there are 39 pumped hydro storage installations with more than 22 GW capacity, averaging more than 500 MW for each system. Electrochemical storage and flywheels are typically only a few megawatts and CAES normally range from 10–100 MW.

Table 15
Summary of Existing Energy Storage Capacity by Technology Type

Technology Type	Total Installations	Total Capacity *MW*
Pumped Hydro	39	22,395
Thermal Storage	105	525
Electrochemical	151	279
Compressed Air	3	114
Flywheel	26	87
All	**324**	**23,399**

Source: U.S. Department of Energy, DOE Global Energy Storage Database, online at http://www.energystorageexchange.org/

Sixty energy storage projects are currently under construction, with the majority of them using battery technology. The largest installations though are thermal storage systems currently under construction in California and Nevada that are associated with solar thermal plants with molten salt storage. An additional 38 projects are either under contract or announced. Five are pumped storage plants with a combined capacity of about 4 GW, two are compressed air projects, and 26 of them are batteries with about 73 MW of total capacity. Table 16 provides a complete breakdown of the projects that are either under construction or in the planning stage.[367]

Table 16
Summary of Energy Storage Capacity under Development by Technology Type

	Under Construction			Announced/Contracted		
Technology Type	**Total Installations**	**Total Capacity** *MW*	**Total Capacity** *MWh*	**Total Installations**	**Total Capacity** *MW*	**Total Capacity** *MWh*
Pumped Hydro	0	0		5	3,950	
Compressed Air	1	0	0	2	309	3,041
Electrochemical	57	24	67	26	73	185
Flywheel	0	0	0	4	10.2	0.1
Thermal Storage	2	260	2,300	1	6	12
All	**60**	**284**	**2,367**	**38**	**4,348**	**3,237**

Source and notes: U.S. Department of Energy, DOE Global Energy Storage Database, online at http://www.energystorageexchange.org/. For Pumped Hydro storage, total capacity in MWh is not provided as the discharge duration is not related to the technology itself but to the size of the pond. In addition, reported storage values vary widely for Pumped Hydro storage facilities, making meaningful reporting difficult. Technologies with bad data on discharge duration (such as 0 hours) are excluded.

The following sections will review the existing and in-development capacity for each of these technology types based on the DOE global energy storage database, along with a brief discussion of their technical capabilities for serving different functions except for end-use thermal storage. End-use thermal storage technologies, such as ice thermal storage and heat thermal storage, are not covered in this section because they do not convert thermal energy back to electricity, thus from a system perspective they are not power sources. Also solar thermal storage technology is not covered since it is an integrated part of the solar power plant that does not operate independently and, unlike other storage technologies, it does not absorb power from the grid.

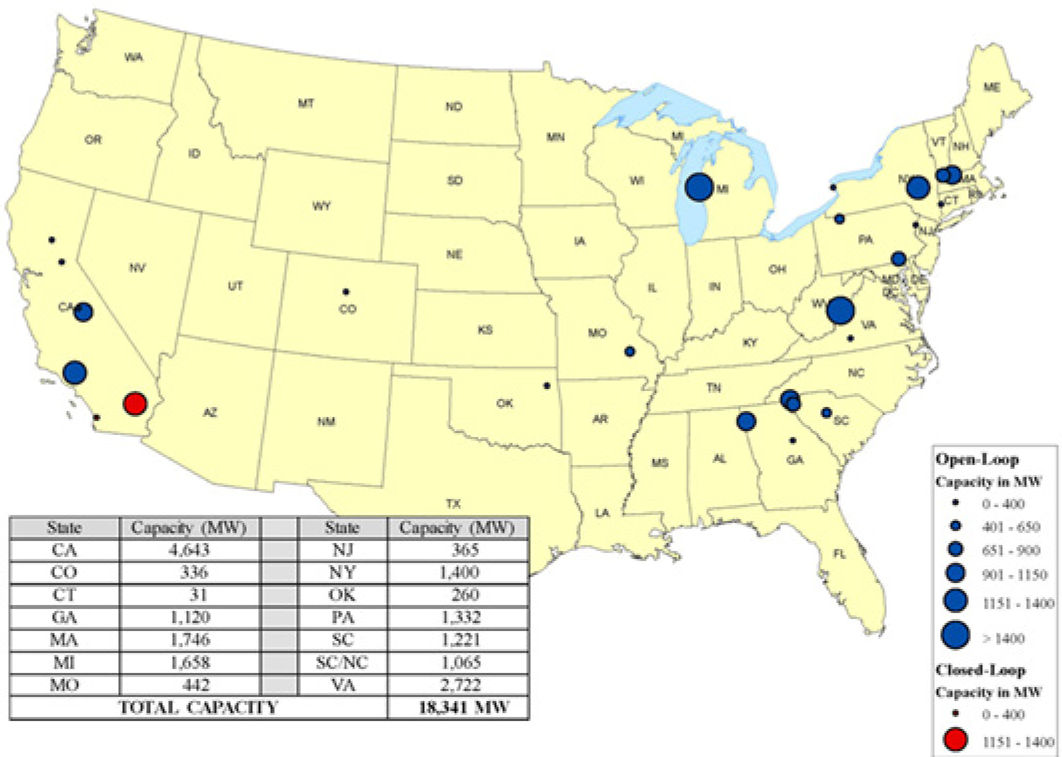
2. Pumped Storage

Pumped storage is a mature and widely-used energy storage technology used both in the U.S. and worldwide. In a pumped storage plant, electricity is used to pump water to an upper reservoir and hydraulic turbines generate electricity when the water flows back down to the source. The size of pumped storage projects can vary greatly, from tens of megawatts to several gigawatts.

[367] U.S. Department of Energy, DOE Global Energy Storage Database, online at http://www.energystorageexchange.org/

The largest domestic pumped storage project is the Bath County Pumped Storage Station located in Virginia with a net generating capacity of 3 GW. In terms of geographical distribution, California and Virginia lead the nation with the largest capacity of pumped storage. There is currently an additional 3167 MW worth of projects that are in some state of licensing or relicensing at FERC.[368] Figure 76 shows the capacity by state for licensed pumped storage projects and Figure 77 shows the capacity by state for the pumped storage projects with pending licenses and relicenses in the US.

Figure 75
Licensed Pumped Storage Projects

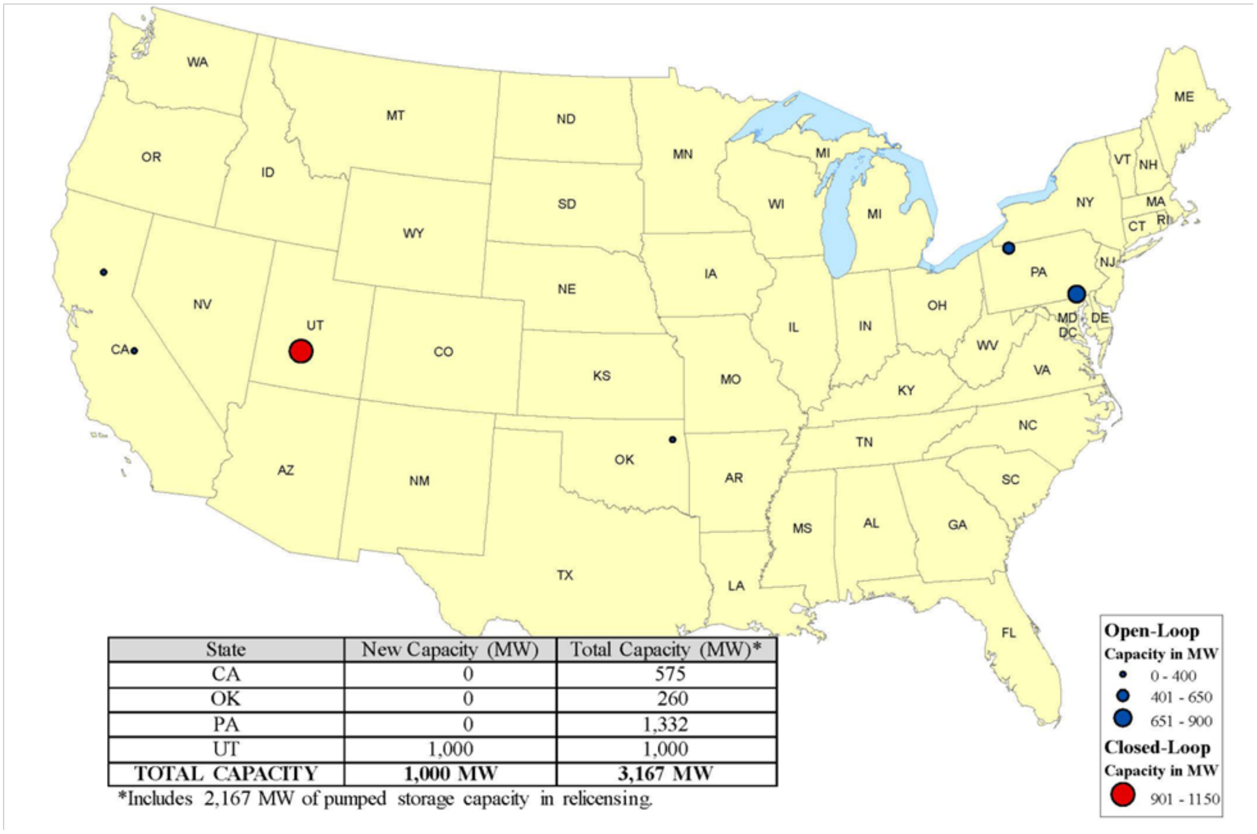


State	Capacity (MW)	State	Capacity (MW)
CA	4,643	NJ	365
CO	336	NY	1,400
CT	31	OK	260
GA	1,120	PA	1,332
MA	1,746	SC	1,221
MI	1,658	SC/NC	1,065
MO	442	VA	2,722
TOTAL CAPACITY			18,341 MW

Source: FERC Staff, Licensed Pumped Storage Projects, October 1, 2014, accessed on Mar 20, 2015, online at: http://www.ferc.gov/industries/hydropower/gen-info/licensing/pump-storage/licensed-projects.pdf.

[368] FERC Staff, Licensed Pumped Storage Projects, October 1, 2014, accessed on Mar 20, 2015, online at: http://www.ferc.gov/industries/hydropower/gen-info/licensing/pump-storage/licensed-projects.pdf

Figure 76
Pending Licenses and Relicenses for Pumped Storage Projects



State	New Capacity (MW)	Total Capacity (MW)*
CA	0	575
OK	0	260
PA	0	1,332
UT	1,000	1,000
TOTAL CAPACITY	1,000 MW	3,167 MW

*Includes 2,167 MW of pumped storage capacity in relicensing.

Source: FERC Staff, Pending Licenses and Relicenses for the Pumped Storage Projects, October 1, 2014, accessed on Mar 20, 2015, online at: http://www.ferc.gov/industries/hydropower/gen-info/licensing/pump-storage/pending-licensed.pdf.

Pumped storage facilities typically can store enough water to operate at full capacity for 15–20 hours or more, which is a major advantage over other storage technologies, and makes it well-suited for energy arbitrage. However, about a quarter of the energy is lost in the pumped storage cycle. Pumped storage can provide all ancillary services that conventional generators provide, such as regulation, spinning, and non-spinning reserves. It can respond faster to system changes than conventional generators (can ramp more quickly), but is slower than batteries and flywheels. Start-up and response times depend on the technology, with newer technologies faster than older technologies. One limitation with older pumped storage designs is that they cannot provide regulation during pumping, but newer pumped storage technology has variable speed pumps, enabling plants to provide frequency regulation while pumping. Further development of pumped storage projects are affected by topographic and environmental constraints.

Under current market structures, options such as dispatchable natural gas are cheaper than pumped storage, making it difficult to construct new plants even after preliminary permits are issued. Pumped storage units also take a much longer time to permit than natural gas plants, with FERC recently testing a shorter two-year licensing process. Changes in the ancillary services markets can also help capture the value of pumped storage and make it a more competitive option.[369]

3. Compressed Air Energy Storage (CAES)

In addition to pumped storage, CAES is the only other storage technology that is currently utilized for bulk energy storage. CAES involves compressing air using electricity from the grid in order to store energy, either in underground caverns or in above-ground vessels. When the stored energy is needed, the released air is heated via combustion using natural gas and is expanded in order to drive a gas turbine to generate electricity.

There are three CAES projects in operation in the U.S., including the 110 MW McIntosh plant owned by Power South in Alabama, the 1.5 MW Isothermal CAES plant owned by SustainX Inc. in New Hampshire, and Texas Dispatchable Wind, a 2 MW onsite wind integration unit. A fourth CAES project—the ATK Launch Systems CAES—is currently under construction. It is co-funded by DOE and Rocky Mountain Power as part of a demonstration project for micro-grids with distributed generation. Two announced projects are a 300 MW Advanced Underground CAES developed by PG&E in California and a 9 MW CAES developed by Next Gen in New York. Apex Bethel Energy Center has also announced a 317 MW underground CAES project in Texas, but it has recently been put on hold as of Oct 2014.[370]

CAES round-trip efficiency is even lower than pumped storage, generally around 60%–70%. Some advanced designs have higher efficiencies but are still under 80%. It can provide response faster than legacy pumped storage, but slower than batteries and flywheels due to increased inertia, and as such is not as efficient as batteries and flywheels in providing regulation service. Underground CAES is also geographically constrained due to the need for underground formations to store the compressed air, although some new ideas such as underwater storage[371] or storage in steel piping (as in the Next Gen CAES project funded by NYSERDA) may somewhat relax this constraint.

4. Batteries

Batteries store electricity in electrochemical form in one or more cells that can convert stored chemical energy back to electricity. There are many different battery technologies currently available. Some are still in early development or demonstration stages, while some have been

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[369] Key, T., L. Rogers, P. March, H. Battey, and R. Dham "Valuing Hydropower Grid Services in the Future Electricity Grid." Hydro Review, April 1, 2013. Available at: http://www.hydroworld.com/articles/hr/print/volume-32/issue-3/articles/valuing-hydropower-grid-services-in-the-future-electricity-grid.html .

[370] U.S. Department of Energy, DOE Global Energy Storage Database, online at http://www.energystorageexchange.org/

[371] Hydrostor, Hydrostor announces partnership for underwater energy storage in Aruba, *PRNewswire*, October 23, 2013, online at: http://www.prnewswire.com/news-releases/hydrostor-announces-partnership-for-underwater-energy-storage-in-aruba-228957251.html.

deployed in both distributed and centralized applications in various sizes. Installation of battery capacity thus far has been limited due to their cost and performance characteristics including limited energy density, cost, lifetime, charging/discharging capabilities, and safety concerns. The most widely deployed technologies are lithium-ion (Li-ion), sodium sulfur (NaS), and lead acid batteries. Li-ion batteries tend to be best suited for relatively short discharges (under two hours) and do not handle deep-discharges well, making these Li-ion batteries more suited to power-management operations such as frequency regulation or as an uninterruptible power source (UPS). NaS batteries have a lower power density than Li-ion batteries but they can maintain longer discharges. Lead acid batteries, are relatively inexpensive, but low energy density and limited cycle lives are challenges to large-scale deployment. Flow batteries are promising, but still require additional development to reach sizes of 1 MW or more. These batteries can sustain a high number of charging cycles over their lifetimes.[372]

Currently, there are only 240 MW of batteries in operation in the U.S. and another 96 MW either under construction or announced. While batteries have ramping speed advantage over pumped storage and CAES, the typical duration for energy storage is limited, at most, to only a few hours.

Figure 75 shows the installed capacity for different batteries in the U.S. electricity system. It shows that the lithium-ion and lead-acid batteries dominate the current installed capacity, whereas the future potential additions are mostly lithium-ion and flow batteries. The growing interest in lithium-ion is partially due to its fast growing application in the transportation sector for plug-in hybrid electric vehicles and all-electric vehicles, and in consumer electronics applications.

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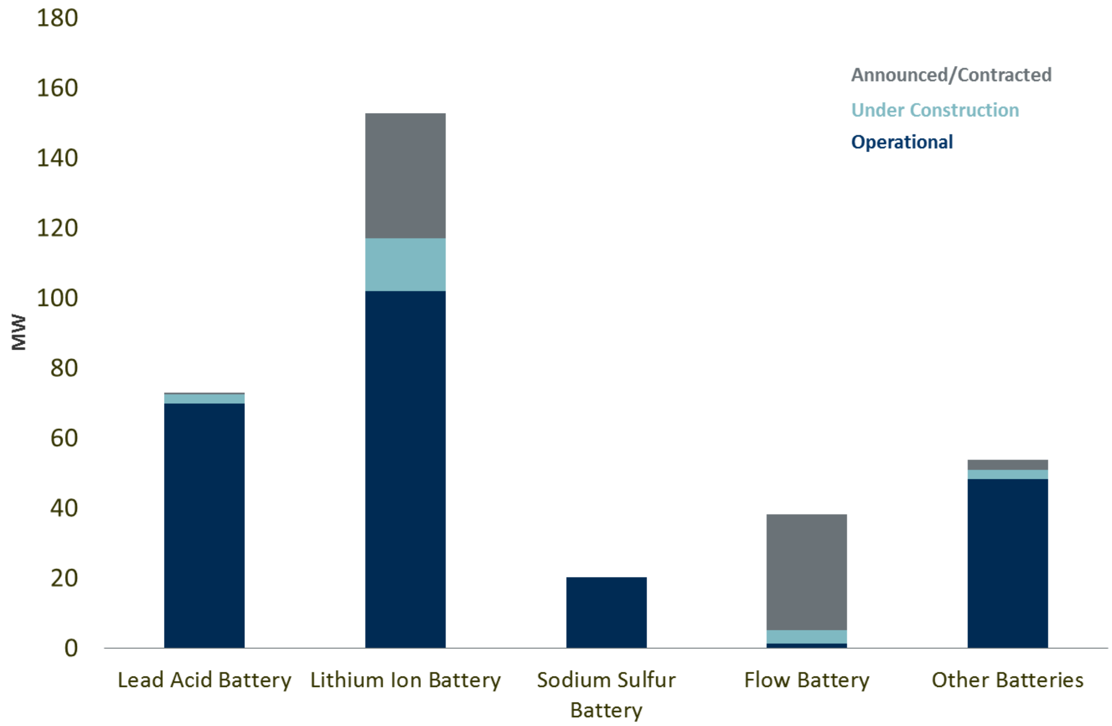
372 U.S. Department of Energy, DOE Global Energy Storage Database, online at http://www.energystorageexchange.org/.

Figure 77
Current and Potential Installation of Battery Storage Capacity



Source: DOE Energy Storage Database.

Batteries can be used for energy arbitrage, but are limited to a few hours due, in part, to the cost of adding more storage capacity per installed kilowatt. As compared to pumped storage and CAES, the most important characteristic of batteries is that they can vary their charging/discharging quickly and accurately in response to a signal from the control room to change MW output up or down. This makes it very valuable for providing regulation service that the system needs to maintain reliability. Another important feature of storage is that it can be small scale, which is useful for distribution applications, and can be moved as needed.

While cost is one major barrier for batteries, the future potential could be hindered by the development of codes, standards, and regulations (CSR) on safety matter if not addressed appropriately. Batteries are different from traditional storage technologies in that they contain chemicals and toxic materials that may pose safety and environmental risk, especially when they are deployed in communities or close to other grid resources such as substations. If CSR issues are not properly addressed and safety problems arise, market acceptance of new technologies might be delayed. Older battery technologies (*e.g.*, lead-acid or NiCd batteries) are currently covered by codes, standards, and regulations and can be more readily deployed. An assessment of existing CSRs in relation to current and emerging ESS technologies is needed to identify any changes to existing CSR and new CSR to cover the new technologies. In this regard, DOE has taken initiatives to organize workshops and research efforts on the development of CSR for energy storage technologies.[373, 374]

5. Flywheels

Flywheels are electromechanical energy storage devices that operate on the principle of converting energy between kinetic and electrical states. A motor accelerates the rotors of the flywheel to higher velocities to store energy; to discharge energy, the rotors reverse the process by generating electricity while slowing down the speed of rotation.

Flywheels are currently commercially available. There are 26 installations in the U.S., with sizes ranging from 100 kW to 20 MW. Beacon Power's second 20 MW project, comprised of 200 flywheels in Hazle Township, Pennsylvania, went into commercial operation in July 2014 to provide frequency regulation service.[375]

Flywheel systems are fast-responding and accurate, with response speed equivalent to batteries and with extremely high cycles. They are best-suited for short durations to supply frequency-regulation services. Another attractive feature of flywheels is that there is no penalty for deep discharge (which there is with a number of battery systems). Some flywheel technologies can be easily moved as needed, which is useful for distribution applications.

C. Current and Emerging Role of Storage

As described above and shown in Table 17, each energy storage technology can provide different functions. While the capability to provide each function exists, any single energy storage facility may not be developed to provide all of the functions, as some of them have low market values and there are other alternatives that are more cost-effective than storage technologies. For example, although flywheels can provide frequency regulation, spinning reserve, and non-spinning reserves, they are unlikely to be developed to provide spinning and non-spinning reserves, which is better served by conventional generating resources. However, once a flywheel project is developed for frequency regulation, which is a higher value product, they could be used for spinning and non-spinning reserves if the capacity is idle.

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373 Conover, DR, *Overview of Development and Deployment of Codes, Standards and Regulations Affecting Energy Storage System Safety in the United States*, Pacific Northwest National Laboratory, PNNL-23578, August 2014, available at http://www.sandia.gov/ess/docs/safety/Codes_101_PNNL_23578.pdf.

374 Conover, DR, *Inventory of Safety-related Codes and Standards for Energy Storage Systems with some Experiences related to Approval and Acceptance*, Pacific Northwest National Laboratory, PNNL-23618, September 2014, available at http://www.sandia.gov/ess/docs/safety/ESS_Inventory_9-15-14_PNNL_23618.pdf.

375 Beacon Power, Beacon Power LLC Flywheel Storage Plant in Pennsylvania Reaches Full Commercial Operation, Press Release, July 31, 2014, available at http://beaconpower.com/wp-content/uploads/2014/07/bp_news_hazle-commissioning-20MW-073114.pdf.

Table 17
Summary of Functions Provided by Energy Storage Technologies

	Pumped Storage	CAES	Flywheel	Batteries		
				NaS	Li-ion	Lead-acid
Short term energy arbitrage (within a day)	++	+		++	++	
Long term energy arbitrage (multiple days)	++	+				
Electric supply capacity	+	+		+	+	+
Frequency regulation	+	+	++	++	++	+
Spinning and non-spinning reserve	+	+	+	+	+	+
Load following	+	+	+	+	+	+
Voltage support	+	+	+	+	+	+
Backup power				+	+	+
Black start	+	+		+	+	+

Source: The Brattle Group

The remainder of this section provides further details on the different roles that energy storage can play in the electricity system.

1. Energy Arbitrage and Peak Shaving

The primary role of storage in today's electricity system is peak shaving and energy arbitrage. Like electricity demand, electricity prices can vary significantly throughout the day and between days. Energy storage is able to take advantage of price variations by storing low cost energy during off-peak hours, and then discharging the stored energy as electricity when the prices are higher. As a result, storage can flatten the shape of the load met by other generators. The amount of energy that a storage system can store is an important factor in determining the degree of peaking shaving and load leveling, and accordingly the ability to arbitrage the price difference. For this reason, pumped storage and CAES are the best technologies for energy arbitrage because they can store more energy than other technologies.

2. Provide Ancillary Services, Especially Frequency Regulation

Frequency regulation is a high value product that batteries and flywheels can provide more effectively than conventional technologies as they provide both regulation up and regulation down services and can switch from charging to discharging almost instantaneously. Providing ancillary services is an area where storage can be very effective and has already been deployed. Currently most regulation service is provided by conventional generating resources and pumped storage, but batteries and flywheels have an advantage over these resources in speed and accuracy. In addition, unlike conventional resources, there is no minimum load requirement for batteries and flywheel to provide frequency regulation services. The combination of these factors means that battery and flywheel technologies can supply more regulation per installed MW than conventional technologies.

While there are other AS such as spinning reserve and non-spinning reserve that storage can provide, these AS can normally be provided by conventional non-storage resources. However, these AS are value streams that storage can capture to improve overall economics.

3. Renewable Integration

As discussed in the background section, one of the trends in the industry is the expansion of intermittent renewable resources due to Renewable Portfolio Standards, and carbon emission reductions targets at the state and potentially national levels. A large penetration of renewables poses multiple operational challenges. Although several solutions exist to address these challenges, storage technologies are well suited to address some of the challenges.

a. Providing AS, especially regulation

Increased generation from intermittent renewables will increase ancillary service requirements. In most systems today, ancillary service requirements are met by conventional generators. Even with high wind and solar penetration, conventional generators can still provide needed ancillary services, but conventional generation may not be able to provide all needed ancillary services if renewable penetration grows in the future. In part, this will depend on the regional grid in question. Given the superior performance of battery and flywheel technologies, they are excellent tools to address the intermittency issue and the associated balancing requirements due to higher levels of variable renewable penetration, whether at the central grid level, where storage can be used as an independent resource or co-located to a wind or solar plant, or in a distributed PV setting, where small batteries can be located close to or co-located with the PV system.[376]

b. Responding to Very Rapid Net Load Movements (Load Following)

Rapid net load movements are common in systems with large renewables generation, including wind and solar. Solar may result in a very large increase in solar output in the morning relative to the increase in load, with a very sharp drop in evening solar output relative to the drop in evening load, as illustrated by the very steep morning and evening ramps predicted by the California ISO when more solar PV is installed in California. This rapid change in net load may

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[376] Bjelovuk, George, American Electric Power's Utility-Scale Energy Storage, presented at NARUC Summer Committee Meetings 2010, n.d., online at:

http://www.narucmeetings.org/Presentations/Bjelovuk,%20Energy%20Storage%20and%20Renewables,%20NARUC,%207-18-10.pdf.

be a problem for the conventional generating system in California.[377] This can be addressed with fast ramping capacity such as some modern gas-turbine based units, pumped storage and conventional hydro. For this reason most of the new pumped storage is planned for California in anticipation of the net load ramping challenges caused by California's 33% RPS. In addition to the 4,100 MW of pumped storage in California today, there is an additional 2,200 MW of pumped storage under development in California as shown in Table 18.[378]

c. Avoiding Renewable Curtailment

Storage can be used to avoid forced reduction in renewable output when the renewable power is in excess by charging when there is excess renewable generation and discharging when load is high. It is not clear that this is an optimal use for storage. Some level of renewable generation curtailment is acceptable, or other operational options such as flexible load or generation resources could be utilized to avoid renewable curtailment.

IEEE summarized their view on energy storage for variable renewables integration as follows:

> At higher penetration levels, mandated by some state Renewable Portfolio Standards (RPS) extensive studies and real world experience integrating intermittent renewables in the USA power system, **up to annual energy penetration levels of around 30%, have shown that the variability and uncertainty can be tolerated if traditional power system planning and operations are updated**. This assumes availability of options such as demand response and fast responding conventional generation along with expansion of transmission and consolidation or coordination of balancing areas (authorities) to reduce the impact of variability through integration over larger footprints and reduce uncertainty through more frequent and accurate forecasts of renewable output. (Emphasis is in the original text).[379]

At higher renewable penetrations, larger amounts of flexible resources may be required to maintain operation of the electric system; storage may be a cost-effective technology solution for providing the necessary flexible capacity.

4. Deferring Investment in Transmission and Distribution

Investment may be needed to upgrade existing transmission and distribution lines when the peak load approaches the system's capacity. As newer storage technologies are small scale and can be conveniently sited at a location where they are needed, they can be used to shave the peak load on a substation enough to defer the need for the upgrade for some years. Furthermore, in the future, the battery system can be moved to another location where it can provide a similar

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377 Net load is the remaining load after deducting the solar generation; it is the remaining load that the grid must meet.

378 U.S. Department of Energy, DOE Global Energy Storage Database, online at http://www.energystorageexchange.org/

379 IEEE Report to DOE QER on Priority Issues*, op. cit.*

investment deferral benefit. Puget Sound Energy provides one such example: it is installing a 3 MW battery on Bainbridge Island, WA, to defer distribution investment to accommodate forecasted load growth for about 9 years. It has been found that when applied to a site on Bainbridge Island, a 4 MW/16 MWh storage system can yield an acceptable return on investment.[380] Con Edison, the utility company serving metropolitan New York area, has filed a proposal to New York Public Utility Commission (NYPUC) for deferring the cost of building a $1 billion substation to meet future load growth in Brooklyn and Queens by using demand side resources, which includes storage, energy efficiency, and distributed generations.[381]

5. Improving Reliability and Resiliency

Energy storage can improve the reliability and resiliency of electricity supply at both the bulk grid level and the distributed level. At the grid level, it can be used to provide the energy needed to operate transmission and distribution lines after a catastrophic failure of the grid and to assist black start operations. The Long Island Power Authority has recognized this usage and thus included storage as part a 1,630 MW resource procurement, in which the Long Island Power Authority is seeking up to 150 MW of storage to assist black start operations and also complement planned increases in renewable resources.[382]

Because batteries can be sited with little or no geographical constraints, they can also be at customers' sites and used to improve reliability and resiliency at the distributed level. In the event of an outage on a radial distribution line, the system can almost instantaneously (within seconds) be unsynchronized or islanded and switched to the battery for uninterrupted power supply for a few hours. AEP has been deploying NaS batteries in several regions such as Ohio, West Virginia, Indiana, and Texas for this purpose.[383] As another example, a 1 MW NaS battery was installed in a remote town in British Columbia that allows the town to operate islanded from the grid during an outage. Two weeks after its installation, the town experienced the first outage

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380 Balducci, Patrick, Patrick Leslie, Chunlian Jin, *et al.*, *Assessment of Energy Storage Alternatives in the Pudget Sound Energy System, Volume 1: Financial Feasibility Analysis*, Pacific Northwest National Laboratory, PNNL-23040, December 2013 ("Balducci, *et al.*, 2013"), available at

http://www.pnnl.gov/main/publications/external/technical_reports/PNNL-23040.pdf

381 Letter from Martin F. Heslin (conEdison) to Hon. Kathleen H. Burgess (Secretary, NYPSC) re Con Edison's Electric, Gas, and Steam Rates, Con Edison's Brownsville Load Area Plan, Cases 136-E-0030, *et al.*, August 21, 2014, available at

http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BFA6E8548-E790-4E6A-8BF2-61DDF62EAB4E%7D.

382 Long Island Power Authority, Request for Proposals for New Generation, Energy Storage and Demand Response Resources, http://www.lipower.org/proposals/docs/GSDR-clean.pdf, accessed Mar 2015.

383 American Electric Power, Electric Transmission Texas Signs Contract for Largest Utility-scale Battery in U.S., News Release, online at http://www.aep.com/newSroom/newSreleaSeS/Default.aspx?id=1560.

and the battery system provided its backup power for 7 hours.[384] In addition, Oncor in Texas is installing five batteries in South Dallas neighborhoods, providing backup power to schools, traffic lights, and a fire station. Each 50 kW battery can power three to five houses for three hours.[385] New York City's Metropolitan Transit Authority (MTA) will install a 400 kWh array of CellCube vanadium redox flow batteries at the MTA's headquarters building in Manhattan. The system will be capable of multi-hour energy storage, and is intended to test energy management at the facility, and provide backup in times of need. All these examples demonstrate the potential values that storage systems, especially batteries can add to the reliability and resiliency of the power supply.

D. SUMMARY OF EXISTING MANDATES/PILOTS FOR ENERGY STORAGE

While high cost and technological challenges have prevented wide-spread adoption of newer storage technologies, several regions and companies have begun to procure storage capacity for their systems.

California is the first state that has mandates for utilities to procure energy storage. In December 2010, the California Public Utilities Commission (CPUC) opened Rulemaking R. 10-12-007 to set policy for California utilities and load serving entities to consider the procurement of viable and cost-effective energy storage systems. In October 2013, the CPUC adopted an energy storage procurement framework and established an energy storage target of 1,325 megawatts for PG&E, Edison, and SDG&E by 2020.[386]

More specifically:

- 1,325 MW of energy storage to be procured by the three IOUs by 2020 with installation required no later than the end of 2024.
- As shown in Table 18, specific procurement targets are set for each utility and for specific application domains, including transmission, distribution, and customer side by years.
- Large-scale pumped storage projects bigger than 50 MW are excluded.
- Utility ownership of the project is limited to 50%.
- The first competitive solicitation will be completed in December 2014.

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384 S&C Electric Company, "Canada's First Utility-Scale Energy Storage System Islands Remote Town During Outages," Case Study, Energy Storage, March 3, 2014, available at http://www.sandc.com/edocs_pdfs/EDOC_078092.pdf.

385 Cameron, Claire. "Oncor to test battery storage on grid," *Utility Dive*, May 12, 2014, online at http://www.utilitydive.com/news/oncor-to-test-battery-storage-on-grid/262122/.

386 California Public Utilities Commission, Decision Adopting Energy Storage Procurement Framework and Design Program, Rulemaking 10-12-007 (Filed December 16, 2010), October 17, 2013, available at http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M078/K912/78912194.pdf.

Table 18
Proposed Energy Storage Procurement Targets in MW required by CPUC

Storage Grid Domain Point of Interconnection	2014	2016	2018	2020	Total
Southern California Edison					
Transmission	50	65	85	110	310
Distribution	30	40	50	65	185
Customer	10	15	25	35	85
Subtotal SCE	**90**	**120**	**160**	**210**	**580**
Pacific Gas and Electric					
Transmission	50	65	85	110	310
Distribution	30	40	50	65	185
Customer	10	15	25	35	85
Subtotal PG&E	**90**	**120**	**160**	**210**	**580**
San Diego Gas & Electric					
Transmission	10	15	22	33	80
Distribution	7	10	15	23	55
Customer	3	5	8	14	30
Subtotal SDG&E	**20**	**30**	**45**	**70**	**165**
Total - all 3 utilities	**200**	**270**	**365**	**490**	**1,325**

Source: Rulemaking 10-12-007, CPUC, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M079/K533/79533378.PDF.

In addition to the three IOUs, Imperial Irrigation District (IID), the third largest public power utility in California, issued a solicitation in early 2014 to procure 20 to 40 MW of battery storage that can accommodate a very broad range of specified operational characteristics.[387]

While California's is currently the most significant program for increasing storage capacity in the electric power system, other regions and utilities are pursuing the installation of storage technologies for providing immediate value to the system, as well as providing opportunities for building and testing newer technologies at pilot scale.

- As part of the contingency plan for the potential closure of the Indian Point nuclear reactor, ConEdison filed a proposal to provide 100 MW of load reduction measures including demand response, energy efficiency, and energy storage. The proposed incentives to its electric customers offer $2,600/kW for thermal storage and $2,100/kW for battery storage systems that provide summer on-peak demand reduction. There are additional bonus incentives available for large (>500kW) projects. Incentives will be capped at 50% of the project cost (plus a bonus for large projects).[388]
- Hawaii has the highest electricity prices in the U.S. due to the use of high-cost oil for generation. In 2008 Hawaiian Electric Company set a goal of sourcing 65

387 Imperial Irrigation District (IID), On-line Solicitation Services, online at https://www.ebidexchange.com/SolicitationList.aspx?cid=974162d4-8c5f-48ee-8cef-8e7bbac1d9e7&uid=00000000-0000-0000-0000-000000000000.

388 ConEdison Green Team/NYSERDA, Enhanced Load Production, presentation, n.d., available at http://www.ny-best.org/sites/default/files/type-page/31348/attachments/ConEdison.pdf.

percent of electricity supply from renewable sources by 2030.[389] However, integrating variable renewables pose substantial challenges because for small island systems, the percent of energy from variable resources quickly becomes a large part of the total generation. To address the challenges, the Hawaiian Electric Company in May 2014 announced that it is seeking proposals for one or more large-scale energy storage systems able to store 60 to 200 MW for up to 30 minutes at rated power output to be in service by early 2017.[390] This request is one of the biggest to date from a single utility.

- In Washington State, $14.4 million grants have been awarded to three utilities by the state government to match federal funding for batteries storage technologies applied in three smart grid demonstration project. The total award is $35.3 million, including funding from DOE's Office of Electricity Delivery and Energy Reliability.[391] The projects are:
  - Avista Utilities—$3.2 million for projects, which include a 1.0 MW/3.2 MWh vanadium flow battery on Washington State University's campus. Pacific Northwest National Laboratory licenses the battery technology. The installed system will: provide energy shifting; provide grid flexibility; improve distribution system efficiency; enhanced voltage control; grid-connected and islanded micro-grid operations. [392]
  - Puget Sound Energy—$3.8 million to install a 2 MW/4.4 MWh lithium iron phosphate battery. The installed system will: provide energy shifting; provide grid flexibility; improve distribution system efficiency; and provide outage management of critical loads.[393]
  - Snohomish County Public Utility District No. 1—$7.3 million to install a 2 MW/6.4 MWh vanadium flow battery and a 1.0 MW/0.50 MWh lithium-ion battery system. The installed system will: provide energy shifting; provide grid flexibility; and improve distribution systems efficiency.[394]

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389 Hawaiian Electric/Maui Electric/Hawai'i Electric Light, Hawaiian Electric Companies submit plans for Energy Future of Hawaii, Press Release, August 26, 2014, online at http://www.hawaiianelectric.com/heco/_hidden_Hidden/CorpComm/Hawaiian-Electric-Companies-submit-plans-for-Energy-Future-of-Hawaii.

390 PRNewswire, Hawaiian Electric seeks energy storage to support renewables for Oahu, Press Release, , May 5, 2014,http://www.hawaiianelectric.com/heco/_hidden_Hidden/CorpComm/Hawaiian-Electric-seeks-energy-storage-to-support-renewables-for-Oahu?cpsextcurrchannel=1 .

391 Green Car Congress, "Three Washington state utilities receive total of $14.3M in matching state grants for grid energy storage projects, July 9, 2014, online at http://www.greencarcongress.com/2014/07/20140709-washington.html.

392 *Id.*

393 *Id.*

394 *Id.*

- Puerto Rico, through the government-owned Puerto Rican electric power company Autoridad de Energia Electrica, has made it mandatory for developers of renewable energy projects to incorporate energy storage into new installations. Under new regulations, operators of renewable energy projects will be required to add 30% of the installation's rated capacity in storage to aid frequency control, as well as the flexibility to keep 45% of the project's capacity in reserve for at least one minute for ramping control to compensate for fluctuations in generated power from variable sources.[395]
- Ontario has also recently moved forward to explore the potential values of energy storage. In December 2013, the Minister of Energy directed Ontario Power Authority (OPA) to work with Ontario Independent Electricity System Operator (IESO) to procure 50 MW of energy storage by the end of the 2014.[396] The procurement process is being conducted in two phases. In Phase I, the IESO would competitively procure up to 35 MW energy storage solutions providing ancillary services to help address issues observed on the power system. This process has been completed and IESO has selected 12 projects with a total of 33.54 MW. Phase II, being conducted by OPA, is designed to procure the remainder of the 50 MW storage target. The procurement is designed to address how storage can best meet the future capacity needs of the system, allow for the deferral of transmission investments, and enhance the value of renewable generation, as well as give consideration to remote applications.

While the examples above are not inclusive of all the mandates and pilots that exist today and are under development, they indicate that the potential values of energy storages are being recognized and their future roles are being explored.

E. Storage Cost Effectiveness

1. Cost of Storage Technologies

The costs of energy storage technologies include capital cost, operation and maintenance (O&M), and charging costs. In general, capital cost is the main driver of the total costs for storage technologies. Figure 78 and Figure 79 illustrate installed costs for a number of storage technologies that have been commercially deployed based on the DOE/EPRI 2013

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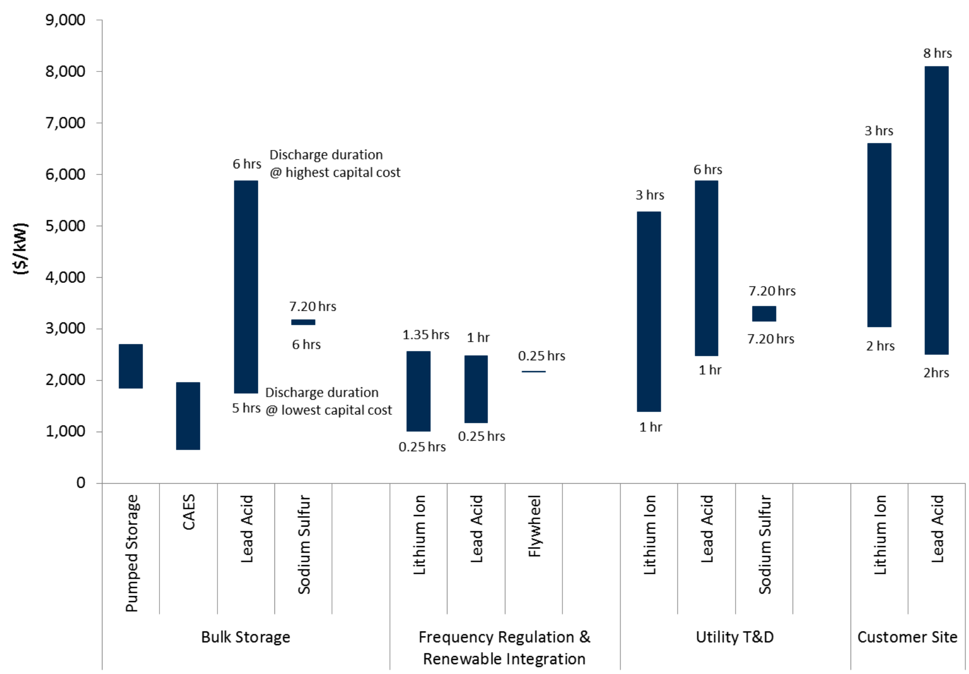
395 Colthorpe, Andy. "Puerto Rico introduces mandate for energy storage in new renewable projects," *PVTech*, December 17, 2013, online at http://www.pv-tech.org/news/puerto_rico_introduces_mandate_for_energy_storage_in_new_renewables_project.

396 Letter from Bob Chiarelli (Minister of Energy, Ontario) to Colin Andersen (CEO, Ontario Power Authority) re Procuring Energy Storage, dated March 31, 2014, available at http://www.powerauthority.on.ca/sites/default/files/news/MC-2014-857.pdf.

handbook.[397, 398] The handbook estimates installed costs based on surveys of battery suppliers, power conditioning system (PCS) providers, and system integrators. The costs are estimated for different applications, including bulk energy service, frequency regulation, renewable integration, utility T&D grid support, and customer site for residential, commercial, and industrial customers. For battery storage technologies, the capital cost is a function of the storage application. For example, for an energy arbitrage application that storage usually has an energy storage capacity for 4–6 hours at rated power output. It is very expensive for Li-Ion battery to reach that duration. Thus, the installed per kW cost will be high. However, for a power application, such as the frequency regulation, the storage may only maintain rated power output for 15 or 30 min. This would yield a much smaller $ per kW installed cost.

Figure 78
Installed Costs for Storage Technologies Per Unit of Rated Power ($/kW)



Source and notes: DOE/EPRI 2013 report. While it is not a strictly linear relationship between the discharge duration and the capital cost in $/kW for a technology applied to specific application, in part due to the technology maturity and economies of scale, the relationship holds in general that the longer the duration, the higher the capital cost is.

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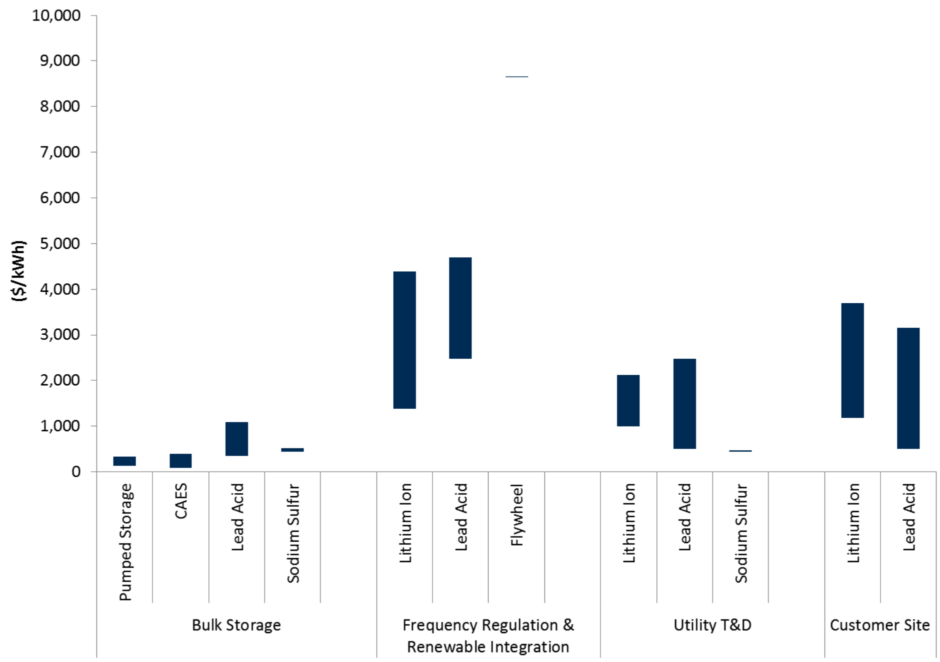
397 Akhil, Abbas A., Georgianna Huff, Aileen B. Currier, *et al.*, *DOE/EPRI 2013 Electricity Storage Handbook in Collaboration with NRECA*, Sandia National Laboratories, SAND2013-5131, July 2013 ("DOE/EPRI 2013 report"), available at http://www.sandia.gov/ess/publications/SAND2013-5131.pdf.

398 Based on the DOE/EPRI 2013 report, "…the installed cost includes all equipment, delivery, installation, interconnection, and step-up transformation costs. For this benchmarking work it was assumed a site was available; however no land costs, permitting, and project planning costs were included. These costs are comparable to the installed costs of a combustion turbine (CT) or combined-cycle gas turbine (CCGT) for up-front capital and financing requirements.…"

Figure 79
Installed Costs For Storage Technologies Per Unit of Energy Capacity ($/kWh)



Source and note: DOE/EPRI 2013 report. The installed cost per unit of energy capacity in $/kWh is calculated as total installed cost/rated power/hours of energy storage at rated Depth of Discharge (DOD).

2. The Cost Effectiveness of Storage

While storage may provide multiple values to the grid, its cost is still high. To determine whether it makes economic sense to develop a storage project requires examining the economic benefits of storage technologies in comparison with the costs. What complicates the analysis of economic benefits is that while certain services can be provided independently, not all services can be provided simultaneously. For example, a storage project using as T&D upgrade deferral to manage substation peak loads may only be needed for a limited number of hours in a year. It is therefore possible for it to provide additional benefits to the electric system such as ancillary services, but only during times when it is not being used to reduce load on the substation. Thus, it is not appropriate either to account only for an individual service or to simply sum up all the individual services a storage project can provide.

EPRI performed an analysis to evaluate the cost-effectiveness of energy storage technologies in California for CPUC to assist its rule making R.10-12-007 for energy storage procurement targets.[399] In its study, it analyzed the benefit-to-cost ratios of storage technologies under different scenarios for three applications: bulk energy storage, ancillary service (frequency

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[399] Kaun, B. and S. Chen, *Cost-Effectiveness of Energy Storage in California: Application of the EPRI Storage Valuation Tool to Inform the California Public Utility Commission Proceeding R. 10-12-007*, EPRI 3002001162, June 2013 ("CPUC/EPRI 2013 report"), available at http://www.cpuc.ca.gov/NR/rdonlyres/1110403D-85B2-4FDB-B927-5F2EE9507FCA/0/Storage_CostEffectivenessReport_EPRI.pdf.

regulation only), and distribution energy storage at a substation to defer update investment.[400] Under most of the scenarios, it showed that energy storage can be cost effective. However, as noted in the report, these results are sensitive to the CPUC assumptions for storage technology costs and future market prices for energy, capacity, and ancillary services products.

The EPRI method has two major limitations: first, as identified in the EPRI report,[401] the model is static and uses point estimate inputs for price (energy, capacity, and AS). Thus it does not consider the indirect impacts of storage deployment levels on market prices. As more energy storage is added, price differentials across the day would be expected to decline as would AS prices. On the other hand, higher renewables penetration would increase the price of AS. These dynamics are not captured in the EPRI framework. Second, the EPRI methodology does not take non-storage alternatives into account. An integrated analysis is needed to assess the economic competitiveness of energy storage from a system evolution perspective.

A system level analysis is pertinent to the Integrated Resource Planning (IRP) and transmission planning processes. Storage resources are not usually included in the planning process. They are more of an afterthought. Resource planning analysis should start to include energy storage as one of the resource options along with generating resources and/or transmission resources. Hawaiian Electric Company has started to model energy storage in its 2013 IRP.[402] Each of the Hawaiian Islands is an independent system with a small number of very expensive, mostly oil-fired units. With a 25% RPS requirement by 2020, and limited overall flexibility to provide AS from conventional resources, storage is a more important economically viable option for renewable integration than it is on the U.S. mainland.

Including storage in planning models is complex and requires new tools. A recent analysis by PNNL deployed a modeling tool to evaluate multiple services, including capacity values, balancing services, arbitrage, distribution upgrade deferral, and outage mitigation benefits in an optimal control strategy framework. An analysis was done for Puget Sound Energy of the financial feasibility of a battery system at a site on Bainbridge Island comparing multiple revenue streams with the revenue requirements to cover the costs of the system[403].

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400 In each of the three areas, multiple values streams are accounted for to the extent that they can be provided simultaneously with the focused area taking the highest priority, except for ancillary service application area where only frequency regulation service is accounted for.

401 CPUC/EPRI 2013 report.

402 Hawaiian Electric Companies, *2013 Integrated Resource Planning Report*, June 28, 2013, attachment to Letter from Patsy H. Nanbu (Hawaiian Electric) to Hon. Chair and Members of the Hawaiian Public Utilities Commission, re Hawaii Electric Companies 2013 IRP Report and Action Plan, Docket No. 2012-0036, June 28, 2013, download available at http://www.hawaiianelectric.com/heco/Clean-Energy/Integrated-Resource-Planning/Hawaiian-Electric-Company-IRP-Reports-and-PUC-Documents.

403 Balducci, *et al.*, 2013.

3. Regulation and Market Design Changes for Monetizing Value

Recognizing the importance of frequency response, the FERC issued three orders that are favorable to energy storage. FERC Order No. 755, issued in 2011, was designed to provide compensation for frequency regulation based on the value of actual service provided, including a capacity payment that includes the marginal unit's opportunity costs and a payment for performance that reflects the quantity of frequency regulation service provided by a resource when the resource is accurately following the dispatch signal.[404] FERC Order No. 784, issued in 2013, expands opportunities for energy storage providers to capitalize on these advances by removing the restriction on third parties selling ancillary services at market-based rates to public utility transmission providers.[405] FERC Order No. 792, issued in 2013 updated the *pro forma* Small Generator Interconnection Procedures (SGIP) and Small Generator Interconnection Agreement (SGIA) to include energy storage as a power source, giving access to faster track interconnections formerly only available to solar PV.[406]

In compliance with FERC Order No. 755, most wholesale markets have implemented changes for regulation markets, including PJM, MISO, CAISO, and NYISO.[407, 408] Despite not being FERC jurisdictional, ERCOT launched a pilot program in 2013 called Fast-Responding Regulation Services (FRRS).

While it is still too early to see the full impact of these market changes on energy storage development, PJM market has shown some encouraging results through its implementation of the change. Since October 1, 2012 when PJM redesigned its frequency regulation market, the number of fast moving resources participating in the regulation market has grown from six to nineteen, representing a combined regulating capability of approximately 490 MW. These resources allowed PJM to reduce the amount of regulation requirement from 1% of peak load in 2012 to 0.78 % of peak load forecast. Finally, in December 2012, the Regulation Requirement was lowered 0.70% of peak load.[409]

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404 U.S. Federal Energy Regulatory Commission (FERC), "Frequency regulation compensation in the organized wholesale power markets," Washington, DC, USA, FERC 755, Dockets RM11-7-000 AD10-11-000, October 2011.

405 U.S. Federal Energy Regulatory Commission (FERC), "Third-party provision of ancillary services; Accounting and financial reporting for new electric storage technologies," Washington, DC, USA, FERC 784, Dockets RM11-24-000 and AD10-13-000, July 18, 2013.

406 U.S. Federal Energy Regulatory Commission (FERC), "Small generator interconnection agreements and procedures," Washington, DC, USA, FERC 792, RM13-2-000, Order 792, November 22, 2013.

407 Kintner-Meyer, Michael. "Regulatory Policy and Markets for Energy Storage in North America," *Proceedings of the IEEE* 102(7), July 2014, download available at http://ieeexplore.ieee.org/xpl/articleDetails.jsp?arnumber=6815664.

408 While in the effort to comply with FERC 755, ISO-NE has not fully implemented it yet as FERC rejected its proposed market change in May 2014.

409 See Letter from James M. Burlew and Craig Glazer (PJM Interconnection) to Hon. Kimberly D. Bose, re Performance-Based Regulation Revisions, Docket Nos. ER12-1204-004 and ER12-2391-003, dated

Continued on next page

These regulatory and market changes help energy storage receive compensation for its frequency regulation value. However, more changes are required to remove barriers that prevent energy storage from capturing all of its values. One issue is that existing regulations and markets are designed based on the categorization of generation vs. transmission and distribution assets, but energy storage spans these categories. For example, in a deregulated market, a T&D owner may not be able to simultaneously own a generating asset to participate in the energy market. This discourages investment on energy storage as it prevents it from monetizing the full value of the storage asset. On the other hand, an independent power producer owning a storage asset that could provide service to a T&D utility may be restricted by current market rules from receiving a bilateral agreement with this utility while participating in the wholesale market to provide energy or ancillary services. New frameworks may be needed to allow energy storage to be compensated for all the services it can provide.

Continued from previous page

October 16, 2013, available at http://www.pjm.com/~/media/documents/ferc/2013-filings/20131016-er12-1204-004.ashx.