Staff Report to the Secretary on Electricity Markets and Reliability

August 2017

Table of Contents

Table of Contents .....

List of Figures .....

List of Tables .....

1 Introduction **1**

2 Findings of This Study **10**

3 Power Plant Retirements **15**

3.1 Coal Plant Retirements 20

3.2 Natural Gas Plant Retirements 24

3.3 Nuclear Plant Retirements 27

3.4 Hydropower Retirements and Repowering 34

3.5 Falling Natural Gas Prices 35

3.6 Environmental Regulations 39

3.7 Growing VRE Deployment 47

3.8 Flattening Electricity Demand 54

3.9 Power Plant Retirements Looking Forward 57

4 Reliability and Resilience **61**

4.1 Assessing Challenges to Reliability 63

4.2 Diversity, Fuel Assurance, and Onsite Storage 89

4.3 High-Risk Events and System Resilience 97

4.4 Enhancing Reliability and Resilience 99

4.5 Reliability and Resilience Looking Forward 100

5 Wholesale Electricity Markets **102**

5.1 Evolution of U.S. Wholesale Electricity Markets 102

5.2 Wholesale Electricity Markets Today 104

5.3 Challenges in Wholesale Electricity Markets 107

5.4 Wholesale Electricity Markets Looking Forward 118

6 Affordability **119**

6.1 Affordability of Generation Portfolios 119

6.2 The Wholesale-Retail Disconnect 120

6.3 Affordability Looking Forward 124

7 Policy Recommendations **126**

8 Areas for Further Research **128**

Appendix A: National and Regional Profiles **130**

Appendix B: VRE Integration Studies **151**

Appendix C: Power Plant Cycling **154**

List of Figures

Figure 1.1. Regions Used in This Study 4
Figure 1.2. Schematic of Typical Daily Load Curve Showing Base Load 6
Figure 3.1. Location of Coal, Natural Gas, Nuclear, and All Other Retirements, 2002–2016 15
Figure 3.2. Net Generation Capacity Additions and Retirements 16
Figure 3.3. Retirements of Coal, Natural Gas, Nuclear, and Other Generating Units, 2002–2022 18
Figure 3.4. Retirements by Date, Location, Ownership, and Capacity 18
Figure 3.5. Operating Generation Capacity, Additions, Retirements, and Announced Retirements by Region for All Generation Types, January 2002–December 2022 20
Figure 3.6. Location of the Existing Coal Fleet 21
Figure 3.7. Location of Coal Retirements, 2002–2016 21
Figure 3.8. U.S. Utility-Scale Coal-Fired Electric Generating Capacity Additions by Coal Type and Initial Operating Year 22
Figure 3.9. Location of the Existing Natural Gas Fleet 25
Figure 3.10. Capacity Additions of U.S. Utility-Scale Natural Gas-Fired Electricity Generation by Technology Type and Initial Operating Year 26
Figure 3.11. Natural Gas Fleet Capacity Factors 26
Figure 3.12. Location of Natural Gas Retirements 27
Figure 3.13. Location of the Existing Nuclear Fleet 28
Figure 3.14. Location of Nuclear Power Plant Retirements: Closed, Announced, and Averted 30
Figure 3.15. Nuclear Plant Retirements Compared to NRC Plant Operating License Terms 33
Figure 3.16. Hydropower Plants in the United States by Capacity and Average Annual Runoff 34
Figure 3.17. Conventional and Shale Natural Gas Production, 2007–2016 36
Figure 3.18. Wholesale Day-Ahead Electricity Prices vs. Henry Hub Natural Gas Price (Monthly Average) 37
Figure 3.19. Total Annual U.S. Natural Gas Generation, 1950–2016 38
Figure 3.20. Heat Rates for Coal, Nuclear, and Natural Gas, 2002–2016 39
Figure 3.21. PJM Merit-Order Dispatch: Various Control Technologies 42
Figure 3.22. Changes in U.S. Coal Capacity, December 2014–April 2016 44
Figure 3.23. Average Coal Plant Capacity Factors, 2008–2014 45
Figure 3.24. Projected and Actual Coal Retirements, 2008–2018 46

Figure 3.25. VRE Generation by Fuel as Percentage of Total U.S. Generation, 2002–2016 48

Figure 3.26. Cumulative U.S. Utility-Scale Wind and Hydroelectric Generation Capacity, 1915–December 2016 48

Figure 3.27. Relationship between the PTC and Annual Wind Capacity Additions 50

Figure 3.28. VRE Penetration as a Percentage of 2016 Generation versus Retired Capacity since 2010 as a Percentage of Non-VRE Capacity 51

Figure 3.29. Gross Domestic Product and Net Electricity Production, Historical (1950–2016) and Projected (2017–2027) 54

Figure 3.30. Estimated U.S. Energy Savings from Structural Changes in the Economy and Energy Efficiency, 1980–2016 55

Figure 3.31. EIA Annual Electricity Sales 2000–2016 (terawatt-hours) and AEO Reference Case Electricity Sales Projections 2017–2030 56

Figure 3.32. Baseload Capacity Additions and Retirements from EIA AEO 2017 (No Clean Power Plan Scenario) 57

Figure 3.33. Modeled Projections for Natural Gas Price, Electricity Sales, and VRE Generation from EIA AEO 2017 (No Clean Power Plan Scenario) 58

Figure 3.34. NGCC Capacity Factors and Number of Starts, 1998–2016 59

Figure 4.1. System Operation Time Scales 62

Figure 4.2. Five-Year Average Reserve Margins across Different Regions (2018–2022) 66

Figure 4.3. Historical Solar On-Peak Capacity Factors in ERCOT 67

Figure 4.4. NERC Definitions of Reserves Used to Provide ERS 70

Figure 4.5. System Frequency after a Grid Event (Top) and How Frequency Control Mechanisms Work to Restore Frequency (Bottom) 71

Figure 4.6. EEI Historical and Project Transmission Investment (Nominal Dollars) 76

Figure 4.7. Location of the Existing Wind Fleet 77

Figure 4.8 Wind Energy Share of Electric Generation by State, 2016 78

Figure 4.9. Ways To Integrate VRE, Arrayed by Type of Intervention and Cost (2014) 80

Figure 4.10. CAISO Load, Net Load, and Wind and Solar Output on Example Weekdays during 2014 82

Figure 4.11. The CAISO Duck Curve 83

Figure 4.12. Demand and Net Demand Shapes at Different Distributed Energy Resource Penetration Levels 84

Figure 4.13. Mapping Reliability Attributes Against Resources 86

Figure 4.14 Selected Ancillary Service Market Design Characteristics 87

Figure 4.15. Ancillary Service Products Exchanged in the Centrally Organized Markets, Listed by RTO/ISO and Category of Ancillary Service 88

Figure 4.16. Generation Mix and Various Economic and Policy Drivers Since 1949, Including Diversity Index 89

Figure 4.17. Changes in U.S. Capacity (Top) and Generation (Bottom) Mix over Time (Left to Right: 2002, 2009, 2016) 90

Figure 4.18. Natural Gas Storage Facilities 93

Figure 4.19. Coal Stocks and Days of Burn, January 2010–May 2017 96

Figure 4.20. Electricity Generation Changes from 2013 to 2014 by Fuel Type 97

Figure 4.21. Sandia National Laboratories' Resilience Analysis Process..... 101

Figure 5.1. Utility Restructuring by State as of May 2017 104

Figure 5.2. The Seven RTOs or ISOs in the United States 105

Figure 5.3. States and Regions along the Spectrum from Traditional to Fully Restructured Electric Markets 106

Figure 5.4. How Market Prices Allow Resource Costs to be Recovered in a Centrally-organized Wholesale Market..... 110

Figure 5.5. Simulated ERCOT Dispatch Curves..... 112

Figure 5.6. Type of Fuel Used in PJM (by Real-Time Marginal Units): 2004 through March 2017..... 113

Figure 5.7. Annual Average Capacity Factors of Coal and Natural Gas Generators 113

Figure 5.8. Negative Northwest Off-Peak Daily Spot Prices ($/MWh) in 2011..... 116

Figure 6.1. Average U.S. Residential Sector Retail Electricity Prices over Time 121

Figure 6.2. Average Wholesale Electric Costs/MWh Have Fallen between 2002 and 2016. 122

Figure 6.3. Day-Ahead, On-Peak Wholesale Electric Prices Reach Near-Record Lows in 2016..... 123

Figure 8.1. Average Three-Year Capacity Factors for Retired U.S. Coal Plants..... 155

List of Tables

Table 3-1. Direct Employment and Income in Industries Related to Electric Power Supply, 2016 23
Table 3-2. Nuclear Plant Retirements, Announced Closures, and Plants Averted by State Action 31
Table 3-3. Average Nuclear Costs by Plant Size and Operator Type, 2016..... 32
Table 3-4. Major Environmental Regulations Related to Coal, Natural Gas, and Nuclear Generation 40
Table 3-5. Fiscal Year 2013 Electricity Production Subsidies and Support 53
Table 4-1. How Various Energy Storage Options Can Deliver Grid-Level Applications 74
Table 4-2. Characteristics of VRE, Grid Integration Challenges, and Mitigation Options..... 78
Table 4-3. Dependence on Imported Just-in-Time Energy for Electricity..... 94
Table B-1. VRE Integration Studies 151

1 Introduction

On April 14, 2017, Energy Secretary Rick Perry issued a memorandum requesting a study to examine electricity markets and reliability. With this document, Department of Energy (DOE) staff are delivering a study that seeks not only to evaluate the present status of the electricity system, but more importantly to exercise foresight to help ensure a system that is reliable, resilient, and affordable long into the future. Therefore, while carefully acknowledging history, this study focuses on the present trajectory of trends that are of particular concern in meeting those long-term goals.

Specifically, the April 14 memo directed a study that explores the following three issues:

- The evolution of wholesale electricity markets, including the extent to which Federal policy interventions and the changing nature of the electricity fuel mix are challenging the original policy assumptions that shaped the creation of those markets;
- Whether wholesale energy and capacity markets are adequately compensating attributes such as on-site fuel supply and other factors that strengthen grid resilience and, if not, the extent to which this could affect grid reliability and resilience in the future; and
- The extent to which continued regulatory burdens, as well as mandates and tax and subsidy policies, are responsible for forcing the premature retirement of baseload power plants.

The U.S. electricity industry is facing unprecedented changes. Last year, for the first time in history, natural gas replaced coal as the leading source of electricity generation. In 2015, a record-high amount of generating capacity retired. Over the course of the last decade, overall growth in electricity consumption at the national level has stalled, while many generation sources—particularly natural gas, wind, and solar—frequently hit new record levels of penetration.

The stakes are high around these issues because electricity is crucial to modern society and economic activity, and because of the physical and financial magnitude of the industry. As noted in the report, *Transforming the Nation's Electricity System: The Second Installment of The Quadrennial Energy Review* (QER 1.2):

> The United States has around 7,700 operating power plants[1] that generate electricity from a variety of primary energy sources; 707,000 miles of high-voltage transmission lines;[2] more than 1 million rooftop solar installations;[3] 55,800 substations;[4] 6.5 million miles of local distribution lines;[5] and 3,354 distribution utilities[6] delivering electricity to 148.6 million customers. The total amount of money paid by end users end for electricity in 2015 was about $400 billion.[7] This drives an $18.6 trillion U.S. gross domestic product and significantly influences global economic activity totaling roughly $80 trillion.[8]

Recognizing how vital electricity is to our society and the health of the U.S. economy, the April 14 memo asked staff to "provide concrete policy recommendations and solutions." It also offered principles for policy formulation: "the Trump Administration will be guided by the principles of reliability, resilience, affordability, and fuel diversity—principles that underpin a thriving economy." To that end, this report concludes by outlining policy recommendations to advance those principles.

Section 2 of this study offers a summary of findings. Sections 3 through 6 provide the analytical framework, relevant data, and research. In addition, each of these sections concludes with a "looking forward" note, as many of the issues raised in the April 14 memo are of growing importance. Section 1

presents policy recommendations available—to DOE and others—to address the issues identified in this study. Section 8 outlines potential areas for further research.

Data Used in This Study

This study uses data collected by the Energy Information Administration (EIA) for the years 2002 through 2017, looking back before 2002 on a few specific issues. The 2002–2017 time range captures several important developments:

- Centrally-organized wholesale electricity markets (Regional Transmission Operators [RTOs] and Independent System Operators [ISOs]) were in the early stages of implementation in 2002. Competition within centrally-organized markets among a large segment of merchant generation did not take effect until the mid-2000s. Three RTO/ISOs initiated mandatory capacity markets in 2006–2007: New York ISO (NYISO), PJM Interconnection (PJM), and ISO-New England (ISO-NE).
- The emergence of a large amount of unconventional natural gas production—the shale revolution—started in 2006–2007. The consequent drop in natural gas prices began in 2009 under the combined impacts of low demand during the economic recession and a significant increase in supply.
- The recession contributed to a significant drop in electricity demand in 2008, and it took several years for demand to return to 2008 levels. Although economic activity has picked up in recent years, electricity consumption and gross domestic product (GDP)—which grew together for decades—now appear less correlated as industries have become less energy-intensive and energy efficiency measures have taken full effect.
- Several environmental regulations implemented under statutes enacted in the 1970s and 1990s, which raise capital and operating costs for affected power plants, had compliance deadlines in the period 2010–2017.
- Driven in part by Federal and state policies, tax incentives, and mandates, significant quantities of variable renewable energy (VRE) resources—specifically wind and solar, and at levels high enough to alter traditional patterns of grid operation—began to impact certain areas around 2010.
- Also around 2010, demand response emerged as a way for customers to compete in most centrally-organized wholesale markets.

Because all of the above factors have emerged over the past 15 years—each affecting power supply and demand in different ways—looking at data since 2002 helps to reveal the impact and interactions of these changes. Additionally, EIA believes that the highly detailed EIA data used in this study (down to the level of individual generators) is most reliable for 2002 forward.

Further, the data used for this study include power plant fuel conversions as retirements for the original fuel source. This study reports power (e.g. generation capacity) and energy (e.g. production or consumption over time) in megawatts (MW) and megawatt-hours (MWh), respectively (unless otherwise noted). Finally, all generation capacity figures reported in this study are net summer capacity as opposed to nameplate (unless otherwise noted).

Defining Regions

The U.S. bulk power system (BPS) is a patchwork of different markets for electricity, shaped over time by technological changes, as well as state, regional, and Federal policies. This patchwork presents organizational and operational challenges, but its diversity also contributes to the system's robustness.

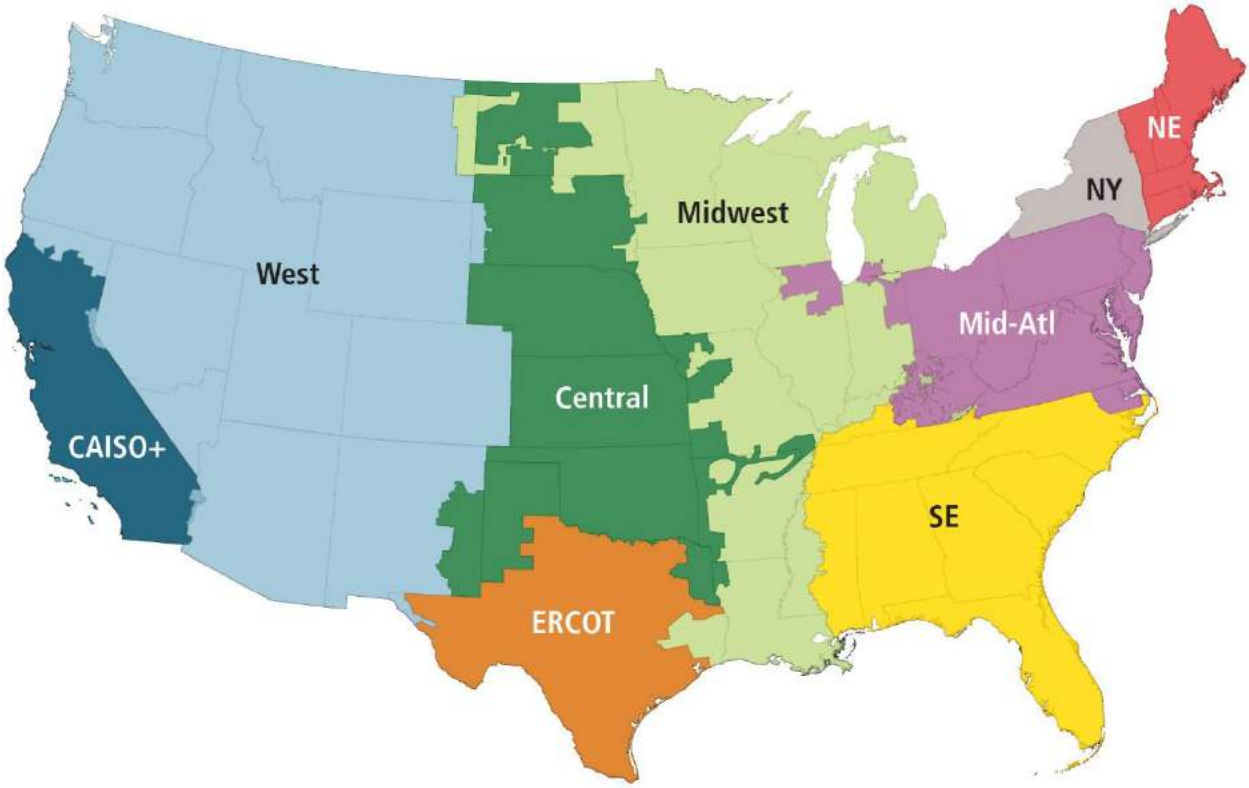
The U.S. power system in the lower 48 states[a] is divided into three synchronized grids: the Eastern Interconnection, the Western Interconnection, and the Electric Reliability Council of Texas (ERCOT).[b, 9] There are limited connections between the Eastern and Western Interconnections, and even fewer connections from ERCOT to the other grids.

Issues confronting the BPS vary widely across regions. This study divides the lower 48 states into nine regions that represent either individual or groups of electric systems, known as balancing authority areas (see Figure 1.1). Within these regions, there are 66 balancing authorities (which can be as small as individual utilities or as large as a multi-state region). Using nine balancing authority-based regions for this analysis is a useful way of aggregating electricity data and revealing regional trends.

[a] Both Alaska and Hawaii have unique islanded electric power systems that are not comparable to the rest of the Nation and thus are not included in this study. This is discussed in detail in a later section.

[b] For most purposes, ERCOT can be considered electrically isolated from the other grids. ERCOT is also not subject to most elements of the Federal Power Act and therefore economic regulation by the Federal Energy Regulatory Commission. A significant exception is Federal Energy Regulatory Commission oversight and regulation of power system reliability, which does apply to ERCOT.

Figure 1.1. Regions Used in This Study[10]



Seven of the nine regions analyzed in this study correlate primarily or directly to the seven ISOs and RTOs in the United States that supply about two-thirds of electricity delivered to end-use customers:[c]

- NE = ISO-NE
- NY = NYISO
- ERCOT = Electric Reliability Council of Texas
- Mid-Atl = PJM
- Midwest = Mid-Continent ISO (MISO)
- Central = Southwest Power Pool (SPP)
- CAISO+ = California ISO (plus smaller balancing areas in the state)

The two remaining regions include numerous balancing authorities, all of which lie outside RTO/ISO service areas:

- SE = Southeast
- West = non-CAISO+ Western Interconnection.

[c] The last four regions in this list include a few additional (mostly small) balancing authorities outside the formal ISO or RTO footprint.

Defining Baseload Generation

This study defines baseload generation as power plants that are operated in baseload patterns—that is, plants that run at high, sustained output levels and high capacity factors, with limited cycling or ramping. While this definition includes most nuclear, coal, and natural gas steam generators, it is not a given that every nuclear, coal, or natural gas steam generator is operated as a baseload plant, or that other technologies cannot function as baseload plants (such as hydroelectric generators). In addition, this study uses the term conventional generation to mean coal, nuclear, and natural gas power plants, regardless of how they are operated.[d]

Other organizations and publications use similar definitions. For example, PJM defines baseload generation as "those units which operate the great majority of hours of the year to meet load requirements."[11]

The North American Electric Reliability Corporation (NERC) offers an explanation as well:

> There is a distinction between baseload generation and the characteristics of generation providing reliable "baseload" power. Baseload is a term used to describe generation that falls at the bottom of the economic dispatch stack, meaning [those power plants] are the most economical to run. Coal and nuclear resources, by design, are designed for low cost O&M [operation and maintenance] and continuous operation […]
>
> However, it is not the economics nor the fuel type that make these resources attractive from a reliability perspective. Rather, these conventional steam-driven generation resources have **low forced and maintenance outage** hours traditionally and have **low exposure to fuel supply chain issues**. Therefore, "baseload" generation is not a requirement; however, having a portion of a resource fleet with high reliability characteristics, such as low forced and maintenance outage rates and low exposure to fuel supply chain issues, is one of the most fundamental necessities of a reliable BPS. These characteristics ensure that "baseload" generation is more resilient to disruptions.[12]

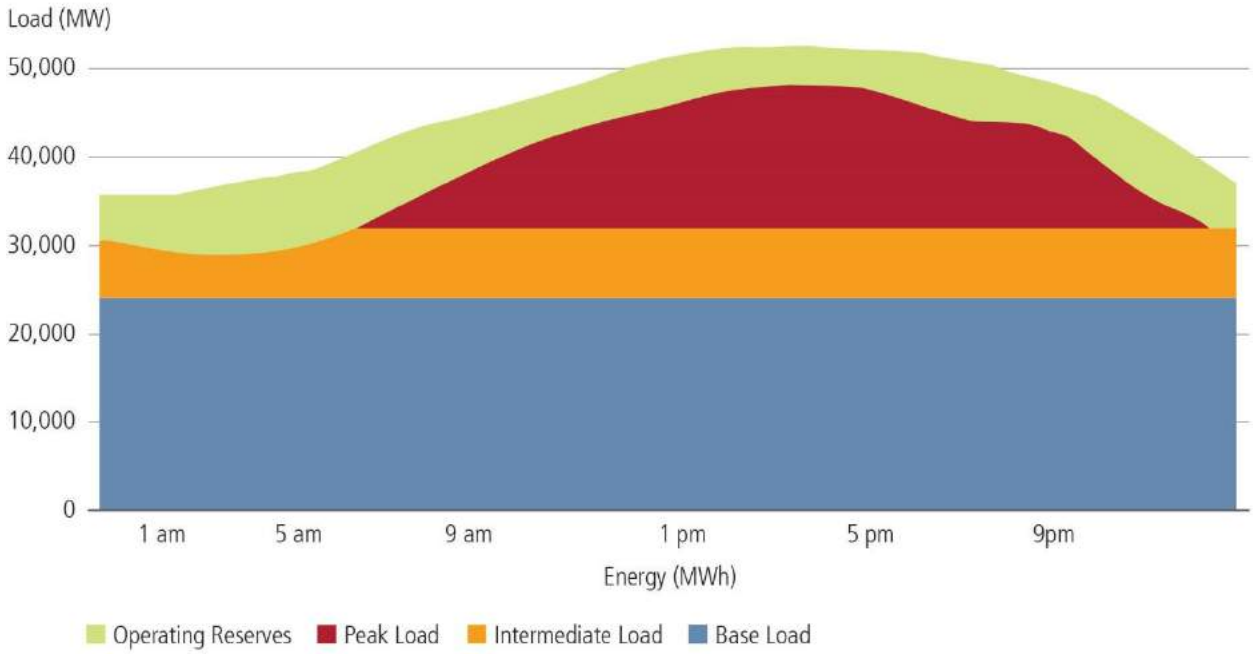
The electricity industry has traditionally referred to baseload generation as the power plants that are used to meet "base" load—the minimum level of electricity that customers demand around the clock, as illustrated in Figure 1.2. Large nuclear, coal, natural gas steam, and hydroelectric plants have historically been used for baseload generation.[e] Baseload plants generally have high capital costs but low fuel costs, and they tend to be fairly fuel efficient. Although the output level of these plants can be changed, they are most economic—in terms of cost per unit of electricity produced—when operated at near-full capacity at all times (although hydroelectric plants are more flexible). Traditional baseload units tend to have longer start-up and shut-down times and generally move (ramp) slowly between production levels to avoid damaging plant components with thermal stress or metal fatigue (see Appendix C on cycling).

---

[d] QER 1.2 does not define the term baseload in its glossary. However, the report states in a caption on page 1-21 that "baseload is considered coal, nuclear, and natural gas combined-cycle plants."

[e] Other technologies that have traditionally operated as baseload include geothermal and biomass power plants. However, those technologies represent a relatively small portion of total U.S. electricity generation; while valuable for the grid reliability services they provide, they are not covered in this report.

Figure 1.2. Schematic of Typical Daily Load Curve Showing Base Load[13]



Intermediate or mid-merit plants are used to follow load, meeting daily variations in demand. Depending on the mix of generation resources available in different regions of the country and relative fuel prices, natural gas and/or coal units are typically used for load following. Short-duration demand peaks, which occur infrequently throughout the year, are generally met by natural gas units with high heat rates.[f] More recently, customer-provided demand response is helping to meet peak demand.

Analysis in Section 3 shows that many of the power plants that retired between 2002 and 2016 were used for baseload generation in the past, but were no longer operating in that role at the time of retirement due to changes in electricity market dynamics. With the sustained drop in natural gas prices, for example, natural gas-fired combined-cycle (NGCC) plants are currently a less costly source of baseload generation than coal or nuclear power in many regions of the country.

VRE resources such as wind and solar are beginning to serve more of minimum load, albeit at variable or intermittent output levels.[g] The proliferation of these sources has also led grid operators in some regions to place an increasing premium on flexible generation resources (e.g., NGCC units) that can help balance VRE variability by meeting base load and intermediate load, both of which are affected by a

---

[f] According to EIA, "Heat rate is one measure of the efficiency of a generator or power plant that converts a fuel into heat and into electricity. The heat rate is the amount of energy used by an electrical generator or power plant to generate one kilowatt-hour (kWh) of electricity." https://www.eia.gov/tools/faqs/faq.php?id=107&t=3.

[g] For the purposes of this study, wind and solar are referred to as VRE. Terms such as "non-dispatchable" and "intermittent" may also apply to these technologies, but for consistency, this study uses the term variable. In contrast, some renewables are dispatchable—that is, sources that can provide power to the grid within sub-hourly time scales to match demand during any 24-hour period. Dispatchable renewables include sources such as biofuels, geothermal, and hydropower (with the caveat on hydropower that it may only be seasonally dispatchable in some cases).

changing net load profile.[h] These factors, among others, have collectively lessened the immediate need for traditional baseload resources in certain regions, but still speak to the need for baseload generation.

Defining Premature Retirement

The dictionary definition of premature is "happening … or performed before the proper, usual or intended time."[14] The Department does not have an official definition for the term "premature retirement"[i] with respect to power plants, as the term is highly subjective. Below are some of the prevailing viewpoints and associated meanings:

- ✓ Power plant engineers may think a power plant retired prematurely if it has not yet run to the end of its nominal design life (for instance, approximately 40 years for post-1970 coal plants) or through the term of reasonable plant life extension modifications.
- ✓ An RTO/ISO or reliability organization may think a power plant retirement is premature if its continued operation is still required to deliver Essential Reliability Services (ERS)[j] in that location (in which case the operator may delay retirement by designating it a "reliability-must-run" resource).
- ✓ A policymaker or legislator may think a power plant has been forced to retire prematurely if the plant delivers benefits that the state or society values, such as emissions-free energy, local jobs, or maintaining local generation.
- ✓ A mayor or employee may think a power plant is retiring prematurely if the retirement causes harms to the community and the individuals who work there.
- ✓ A merchant competitor that built or acquired a power plant may think its plant has been forced to retire prematurely if the merchant has not been able to recover its investment in the plant through sales of energy and capacity or through other revenue streams.
- ✓ A vertically integrated utility executive may think a power plant has been forced to retire prematurely if the utility has not yet fully recovered its rate-based capital investment in the plant and its return on that rate base.
- ✓ Nuclear or hydroelectric plant owners and regulators may think a power plant has retired prematurely if it has not yet run through the full term of its operating license and/or license extension. Federal Energy Regulatory Commission (FERC) hydro licenses run for up to 50 years with potential reauthorizations of 30–50 years, and Nuclear Regulatory Commission (NRC) nuclear operating licenses run for 40 years with potential 20-year extensions.
- ✓ Electricity economists may think a power plant retired has prematurely if the plant was still able to sell electricity competitively against other energy sources but was required to close due to policy directives. On the other hand, economists may also think a power plant retired

---

[h] "Net load" is the instantaneous difference between total customer electricity demand (load) and VRE generation.

[i] QER 1.2—*Transforming the Nation's Electricity System: The Second Installment of the Quadrennial Energy Review*—discussed "premature nuclear retirements" but did not explicitly define the term. For example, in Chapter 3, page 24, the report notes: "When analyzing the impacts of **premature nuclear retirements** on power generation in the state, a state of Illinois report considered a scenario in which 80 percent of the replacement generation was coal. Other analysis concludes that roughly 75 percent of the at-risk nuclear generation nationwide would be replaced with fossil generation, largely powered with natural gas." [notes omitted, emphasis added]

[j] See Section 4.1.1 for a discussion of ERS.

prematurely if the plant provided un-priced benefits to society that, if priced, would have made the plant profitable.

- ✓ A long-term planner and risk manager may think a power plant has retired prematurely if it offered valuable diversity, reliability, resilience, and optionality benefits that are not yet fully recognized, valued, and/or compensated.

Each of these viewpoints represents a valid perspective, particularly those of grid operators and other institutions responsible for reliability. While stakeholders may maintain that a power plant has been forced to retire prematurely based on one or more of the considerations above, the results of this study show that some observed power plant retirements were appropriate and consistent with markets as they are currently functioning. In other words, not every power plant retirement is cause for alarm.

However, NERC is concerned with the trend of retirements as it relates to reliability and resilience. NERC wrote in response to the April 14 memo:

> As conventional resources **prematurely** retire, sufficient amounts of essential reliability services, such as frequency and voltage support, ramping capability, etc., must be replaced based on the configuration and needs of the system.[15] [emphasis added]

Given the difficulty in assigning a single definition to premature retirement, as well as the subjective nature of such a definition, this study does not attempt to determine whether any *specific* power plant retirements have been premature. Instead, this study assesses the various factors that contribute to power plant retirement *trends*.

Topics Beyond the Scope of This Study

This study does not directly address several topics for the following reasons:

- **Cybersecurity** is a critical component to ensuring the reliable and resilient operation of the Nation's energy infrastructure. Existing and emerging cybersecurity threats can affect any aspect of the electric sector, ranging from power plants, to transmission and distribution systems, to customers and end-use devices. The December 2015 attack on the Ukrainian electricity system and the 2012 Shamoon virus targeting the energy sector in Saudi Arabia, for example, were wake-up calls.[16]

  DOE takes these threats seriously and is designated as the Federal Government's lead Sector-Specific Agency for cybersecurity for the energy sector, which entails supporting the cyber protection of the Nation's critical energy infrastructure.[k] However, while cybersecurity is a significant concern and top priority, it is not addressed in this report because it is the subject of an upcoming joint report between DOE and the Department of Homeland Security being prepared in response to Executive Order No. 13800, *Strengthening the Cybersecurity of Federal Networks and Critical Infrastructure*.

- **Alaska and Hawaii**: While the broad trends discussed in this report apply in Alaska and Hawaii as well as the lower 48 states, many of this study's economic observations do not directly apply to the power plants in the Hawaii and Alaska power systems, as they are not large, interconnected energy markets, and utility system operators in the states face unique operational and fuel supply chain considerations.

---

[k] For more information, visit DOE's website on the Department's cyber activities: https://www.energy.gov/national-security-safety/cybersecurity.

The Hawaii and Alaska power systems are remote, vertically integrated systems with plant sizes that tend to fall below the size screens used in this study. The average generating unit sizes in Hawaii and Alaska are 18 MW and 5 MW, respectively, compared to an average unit size of 70 MW in the lower 48 states.[17] Because neither state is interconnected with any of the major U.S. interconnections, or to any transmission or distribution network in Canada, utilities in both states must self-supply all ERS.[l] As a result, utilities in these isolated systems might consider different parameters for reliability in their system planning compared to utilities in the contiguous United States, who can obtain reliability services and products in real time through markets and bilateral transactions.[18] Their experiences, however, may inform the efforts of utilities in the contiguous U.S. seeking to better manage rural systems and effectively integrate VRE and microgrids.

- **Geothermal, biomass, and combined heat and power** plants are often operated as baseload plants, operating at a relatively stable level over a long period of time. However, because these types of plants are not as prevalent or widespread as gas, coal, and nuclear plants, this study did not perform detailed analyses of trends and closures for these technologies.

[l] In 2014, an intertie to the Western Interconnection of British Columbia was proposed to the Alaska Energy Authority in order to bring power to Alaska. However, as of 2016, no further work on the project had been completed due to economic reasons. http://energy-alaska.wikidot.com/railbelt.

2 Findings of This Study

This study identified several critical issues central to protecting the long-term reliability of the electric grid in accordance with the April 14 memo, which asked staff to explore:

1) **The evolution of wholesale electricity markets, including the extent to which Federal policy interventions and the changing nature of the electricity fuel mix are challenging the original policy assumptions that shaped the creation of those markets.**

While centrally-organized markets have achieved reliable wholesale electricity delivery with economic efficiencies in their short-term operations, changing circumstances have challenged both centrally-organized and, to a lesser extent, vertically-integrated markets.[m]

- To date, wholesale markets have withstood a number of stresses. While markets have evolved since their introduction, they are currently functioning as designed—to ensure reliability and minimize the short-term costs of wholesale electricity—despite pressures from flat demand growth, Federal and state policy interventions, and the massive economic shift in the relative economics of natural gas compared to other fuels. The resulting low average wholesale energy prices, while beneficial for buyers of wholesale electricity, represent a critical juncture for many existing baseload generation resources and their role in preserving reliability and resilience.[n]
- Market designs may be inadequate given potential future challenges. VRE—with near-zero marginal costs and if at high penetrations—will lower wholesale energy prices independent of effects of the current low natural gas prices. This would put additional economic pressure on revenues for traditional baseload (as well as non-baseload) resources, requiring careful consideration of continued market evolutions.
- Markets need further study and reform to address future services essential to grid reliability and resilience. System operators are working toward recognizing, defining, and compensating for resource attributes that enhance reliability and resilience (on both the supply and demand side). However, further efforts should reflect the urgent need for clear definitions of reliability- and resilience-enhancing attributes and should quickly establish the market means to value or the regulatory means to provide them.

Evolving market conditions and the need to accommodate VRE have led to the increased flexible operation of generation and other grid resources. Some generation technologies originally designed to operate as baseload were not intended to operate flexibly, and in nuclear power's case, do not have a regulatory regime that allows them to do so.

---

[m] This study also refers to vertically integrated markets as bilateral markets.

[n] Former FERC Commissioner Tony Clark summarizes today's changing demands on centrally-organized markets: "Affordable power was the goal when markets were created. The current markets are still procuring affordable power, but many state public policy makers no longer see that as the only goal […] other public policy goals [include…] incenting in-state jobs, promoting 'green' energy or other politically favored resources, preserving carbon-free resources, and retaining substantial tax revenues to state and local government." Clark goes on to say, "[Markets] were never designed for job creation, tax preservation, politically popular generation, or anything other than reliable, affordable electricity." http://www.wbklaw.com/uploads/file/Articles-%20News/2017%20articles%20publications/Market%20Identity%20Crisis%20Final%20(7-14-17).pdf.

- Generation from VRE can change widely over the course of a single day, which requires dispatchable power plants to be operated more nimbly. Additionally, in some areas of the country, there may be over-generation from VRE at some points in a day, which drives prices to almost zero yet requires quick-ramping assets when VRE subsides. Taken together, these trends have placed a premium on flexible output rather than the steady output of traditional baseload power plants. This flexibility is generally provided by generation resources. However, non-generation sources of flexibility—such as flexible demand, increased transmission, and energy storage technologies—are being explored as ways to enhance system flexibility.

Society places value on attributes of electricity provision beyond those compensated by the current design of the wholesale market.

- Americans and their elected representatives value the various benefits specific power plants offer, such as jobs, community economic development, low emissions, local tax payments, resilience, energy security, or the national security benefits associated with a nuclear industrial base. Most of these benefits are not recognized or compensated by wholesale electricity markets, and this has given rise to a variety of state and private efforts that include keeping open or shutting down established baseload generators and incentivizing VRE generation.

2) Whether wholesale energy and capacity markets are adequately compensating attributes such as onsite fuel supply and other factors that strengthen grid resilience and, if not, the extent to which this could affect grid reliability and resilience in the future.

Markets recognize and compensate reliability, and must evolve to continue to compensate reliability, but more work is needed to address resilience.

- Reliable and affordable electricity is essential to the modern economy, including the manufacturing, services, and financial sectors. NERC's most recent annual *State of Reliability* report concludes that during 2016, the "bulk power system reliability remained within defined performance objectives to provide an Adequate Level of Reliability (ALR)."[o] NERC reached the same conclusion for 2013–2015. However, in a May 2017 letter to the Secretary of Energy, NERC pressed the importance of reliability issues that require attention, including maintaining ERS as conventional generation retires and ensuring flexibility and sufficient transmission to supplement and offset VRE.[19] These issues are indicative of the technological and institutional changes that are now affecting the electricity sector, and dealing with these issues will require new levels of coordination and collaboration among the sector's many constituencies. Presently, BPS reliability is adequate despite the retirement of a portion of baseload capacity and unique regional hurdles posed by the changing resource mix.

- Fuel assurance is a growing consideration for the electricity system. Maintaining onsite fuel resources is one way to improve fuel assurance, but most generation technologies have experienced fuel deliverability challenges in the past. While coal facilities typically store enough

[o] NERC defines ALR as "the state that the design, planning, and operation of the Bulk Electric System (BES) will achieve when the [five] listed Reliability Performance Objectives are met." These objectives are detailed at http://www.nerc.com/pa/Stand/Resources/Documents/Adequate_Level_of_Reliability_Definition_(Informational_Filing).pdf.

fuel onsite to last for 30 days or more, extreme cold can lead to frozen fuel stockpiles and disruption in train deliveries. Natural gas is delivered by pipeline as needed. The NERC letter to DOE emphasized ensuring natural gas fuel supply and mitigating delivery vulnerabilities. Capacity challenges on existing pipelines combined with the difficulty in some areas of siting and constructing new natural gas pipelines, along with competing uses for natural gas such as for home heating, have created supply constraints in the past. Supply constraints can create increased price risk and, in extreme cases, could impact reliability.[p]

- Recent severe weather events have demonstrated the need to improve system resilience. The range of potential disruptive events is broad, and the system needs to be designed to handle high-impact, low probability events. This makes it very challenging to develop cost-effective programs to improve resilience at the regional, state, or utility levels. Planning, practice, and coordination on an all-hazards basis and having a mix of resources and fuels available when a major disturbance occurs are both essential to fast response. Work still remains to identify facilities that merit hardening; stage periodic exercises and drills so that governmental agencies and utilities are prepared for emergencies; and ensure that wholesale electricity markets are designed to recognize and incentivize investments that would achieve or enhance resilience-related objectives.
- Significant progress is already being made to understand what is needed to maintain power system reliability under changing market conditions, but more work is needed to understand what can be done to maintain resilience in a variety of conditions as the grid changes over the coming years. Further, low natural gas prices are driving greater use of natural gas for electricity generation, which has made exposure to natural gas price risk related to availability a growing concern in several regions. There are tradeoffs between multiple desirable attributes of the grid. For example, within power systems, it may be the case that a more reliable and resilient system is more costly than the least-cost system that a centrally-organized wholesale market is intended to deliver. Similarly, policies that seek to deliver more jobs, reduce pollution, or reduce risk may require more upfront investment at an initially higher cost to society as a whole than a least-cost system. It is important that policymakers have a clear understanding of the true costs and benefits of services to the grid, as well as an understanding of the tradeoffs between desirable attributes like reliability, flexibility, and affordability.

[p] Indeed, ISO-NE has repeatedly expressed that reliability and resilience concerns are not being adequately addressed by the New England region on natural gas.

3) The extent to which continued regulatory burdens, as well as mandates and tax and subsidy policies, are responsible for forcing the premature retirement of baseload power plants.

The recent and unprecedented rise of natural gas as a top electricity generation resource, the increase in VRE penetration, the flattening of electricity demand growth, and a host of policy issues—regulations, mandates, and subsidies at the state and Federal levels—have negatively impacted traditional baseload generation, particularly coal and nuclear power plants.

Between 2002 and 2016, 132,000 MW of generation capacity retired—representing about 15 percent of the total 2002 installed base—and 390,500 MW of new capacity was added. While power plants retire for a variety of reasons, several factors have contributed to recent retirements and continuing pressure for additional retirements.

The biggest contributor to coal and nuclear plant retirements has been the advantaged economics of natural gas-fired generation.

- Low-cost, abundant natural gas and the development of highly-efficient NGCC plants resulted in a new baseload competitor to the existing coal, nuclear, and hydroelectric plants. In 2016, natural gas was the largest source of electricity generation in the United States—overtaking coal for the first time since data collection began.[20] The increased use of natural gas in the electric sector has resulted in sustained low wholesale market prices that reduce the profitability of other generation resources important to the grid. The fact that new, high-efficiency natural gas plants can be built relatively quickly, compared to coal and nuclear power, also helped to grow gas-fired generation. Production costs of coal and nuclear plants remained somewhat flat, while the new and existing, more flexible, and relatively lower-operating cost natural gas plants drove down wholesale market prices to the point that some formerly profitable nuclear and coal facilities began operating at a loss. The development of abundant, domestic natural gas made possible by the shale revolution also has produced significant value for consumers and the economy overall.

Another factor contributing to the retirement of power plants is low growth in electricity demand.

- Growth of total electricity use has slowed from averaging 2.5 percent annually in the late 1990s, to averaging 1.0 percent annually from 2000 to 2008, to remaining roughly flat since then.[21] Changes in electricity demand—particularly the apparent decoupling of economic output and electricity demand—have been driven in part by energy efficiency policies. The combination of slow growth in electricity demand and the 390,500 MW of capacity additions from 2002 to 2016 made significant amounts of older, higher-cost capacity redundant.

Dispatch of VRE has negatively impacted the economics of baseload plants.

- Since 2007, the contribution to total generation from wind and solar has grown quickly, accelerated by government policies and mandates. State renewable portfolio standards (RPS) have been the largest contributor—associated with 60 percent of VRE growth since 2000—followed by Federal tax credits and government research (which contributed to the dramatic drop in wind and solar technology costs). Because these resources have lower variable operating costs than traditional baseload generators, they are dispatched first and displace baseload resources when they are available.
- Participants on a panel of economists at a May 2017 FERC technical conference cited state-level RPS and Federal tax credits for VRE as examples of wholesale market impacts and distortions.

Competition from resources that benefit from such policies[q] reduces revenues for traditional baseload power plants by lowering the wholesale electric prices they receive and by displacing a portion of their output.

Investments required for regulatory compliance have also negatively impacted baseload plant economics, and the peak in baseload plant retirements (2015) correlated with deadlines for power plant regulations as well as strong signals of future regulation.

- A suite of environmental regulations scheduled for implementation between 2011 and 2022 has had varying degrees of effects on the cost of generation. For example, the largest number of coal plant retirements occurred in 2015—the deadline for coal and oil plants to add pollution control equipment for Mercury and Air Toxics Standard (MATS) compliance. In the same year, the Environmental Protection Agency (EPA) finalized its Clean Power Plan, which, if fully implemented, would place additional pressure on coal-fired generation. Nuclear power plants also face regulatory costs—principally the Cooling Water Intake Rule. Three nuclear plants that announced closure (Oyster Creek, Diablo Canyon, and Indian Point) have cited disputes with their respective states, who implement the rule, as among the reasons for plant retirement.

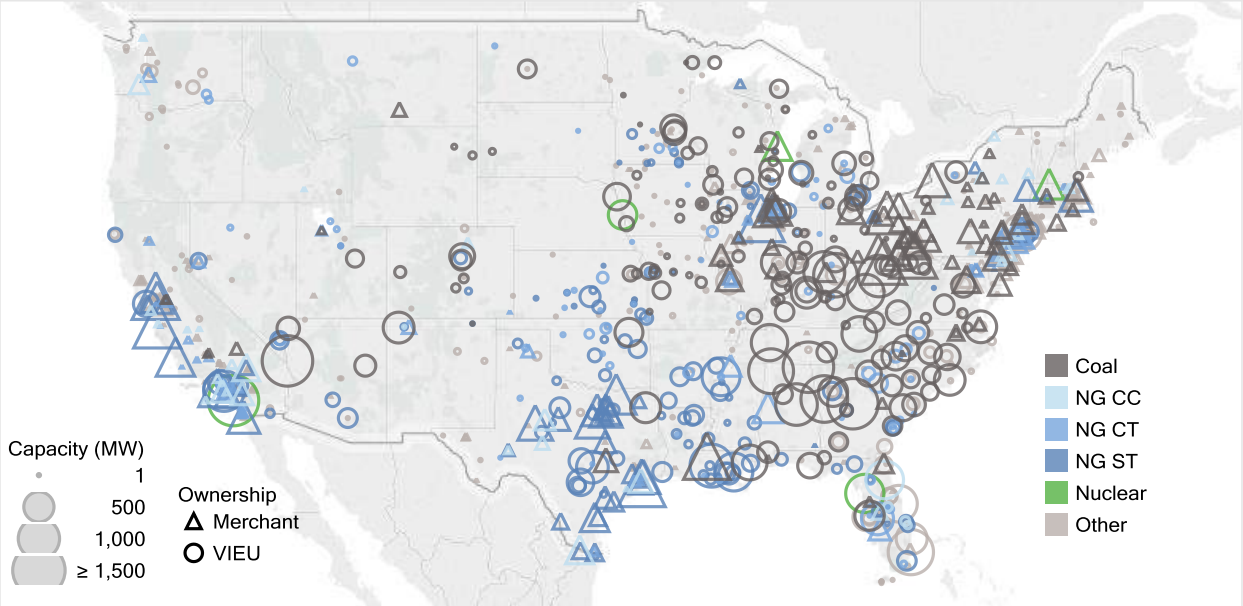
Ultimately, the continued closure of traditional baseload power plants calls for a comprehensive strategy for long-term reliability and resilience. States and regions are accepting increased risks that could affect the future reliability and resilience of electricity delivery for consumers in their regions. Hydropower, nuclear, coal, and natural gas power plants provide ERS and fuel assurance critical to system resilience. A continual comprehensive regional and national review is needed to determine how a portfolio of domestic energy resources can be developed to ensure grid reliability and resilience.

[q] These same economists also cited other "out-of-market" interventions as distorting efficient price formation in wholesale markets, such as recently enacted and pending state laws that provide support to existing nuclear units. During the economist's panel discussion at the FERC May 2017 technical conference, the phrase "subsidies beget subsidies" was used.

3 Power Plant Retirements

A combination of factors is causing power plant retirements, including low natural gas prices, wholesale competition, low customer demand growth, regulation-driven cost increases, and the growth of VRE. As Figure 3.1 shows, the types, magnitude, and timing of conventional power plant retirements vary regionally.

Figure 3.1. Location of Coal, Natural Gas, Nuclear, and All Other Retirements, 2002–2016[22, r]

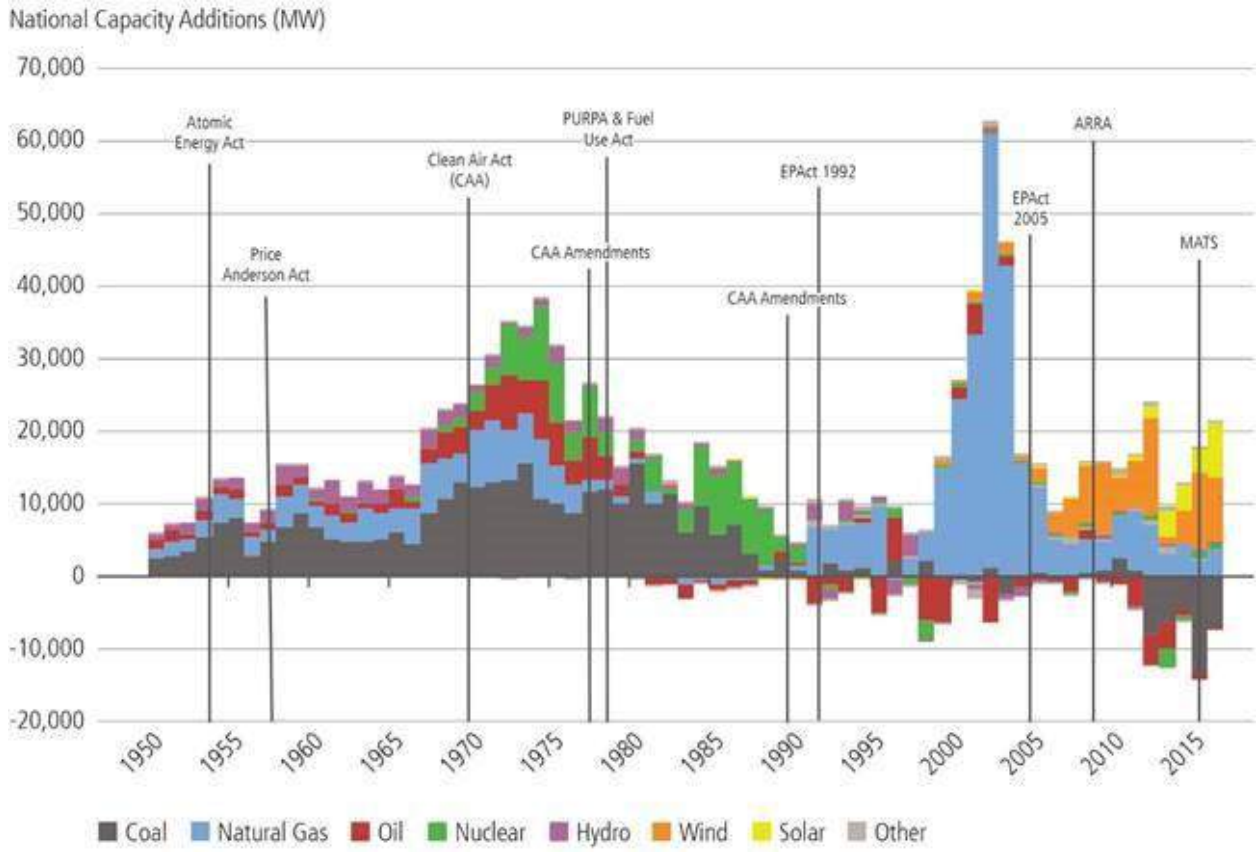


To understand observed power plant capacity *retirements*, it is useful to begin with an examination of historical capacity *additions*. From 1950 to 2015, capacity additions of different generation technologies tended to come in waves that were largely influenced by policy, fuel costs, and technology development (see Figure 3.2). Coal expansion was highest from 1950 to 1990, nuclear power was widely deployed in the 1970s and 1980s, natural gas capacity additions peaked in the early 2000s and continue through today, and VRE has grown rapidly over the last decade.[s]

[r] VIEU stands for vertically integrated electric utilities.

[s] Not depicted: prior to the 1950s, hydropower was a large source of generation capacity additions, the vast majority of which is still operational today. https://www.eia.gov/todayinenergy/detail.php?id=30312.

Figure 3.2. Net Generation Capacity Additions and Retirements[t23]



Power plant retirements have accelerated since 2011, and retirement trends vary significantly by generation source. For instance, the current wave of nuclear plant retirements only occurred over the last five years.[u] Some of the nuclear units now closing are doing so because of state policy pressure (as with California's Diablo Canyon, New Jersey's Oyster Creek, and New York's Indian Point), and some have had maintenance issues that were too costly to fix. However, most plants are closing or threatening closure because–given the economics in some regions—they have become unable to compete against primarily low-cost, gas-fired generation and, to a lesser extent, subsidized and mandated VRE in a low electricity demand environment.

The design of traditional baseload power plants assumed operations primarily at a constant output level with limited cycling (see Appendix C).[24] As the electricity system continues to evolve and market conditions change, these plants are increasingly being moved into load-following operations, or are

[t] Acronyms: Clean Air Act (CAA), Energy Policy Act of 1992 (EPAct 1992), Energy Policy Act of 2005 (EPAct 2005), Investment Tax Credit (ITC), Production Tax Credit (PTC).

[u] However, we note that 29 U.S. nuclear power plants retired from 1974 through 2001, including 13 power plants in the commercial utility nuclear fleet sized at 700 MW or larger. These plants retired for a variety of reasons, including damage (Fort St. Vrain), safety or operational difficulties (Three Mile Island 2, Zion 1 & 2, Millstone 1), costly safety requirements (Humboldt Bay), and state or utility policy choices (Rancho Seco, Trojan, Indian Point 1). This study only looks at the nuclear units in operation in 2002 and beyond.

required to more frequently adjust the load and the on/off dispatch of their units. The extra costs incurred to do so can affect a retirement decision.

QER 1.2 discusses these issues:

> Currently, the changing electricity sector is causing the closure of many coal and nuclear plants in a shift from recent trends. From 2000 through 2009, power plant retirements were dominated by natural gas steam turbines. Over the past 6 years (2010–2015), power plant retirements were dominated by coal plants (37 GW), which accounted for over 52 percent of recently retired power plant capacity. Over the next 5 years (between 2016 and 2020), 34.4 GW of summer capacity is planned to be retired, and 79 percent of this planned retirement capacity are coal and natural gas plants (49 percent and 30 percent, respectively). The next largest set of planned retirements are nuclear plants (15 percent).[25]

Retirements typically can be tied to the units' inability to compete economically, but the factors complicating a given plant's economics can be numerous and can compound each other. Currently, these factors include low wholesale electricity prices (driven by competing generators with low marginal costs, as well as subsidies); higher operating costs from unit age or lower efficiency; and looming capital needs, including compliance with safety and/or environmental regulations; among others. Further, minimal growth in electricity demand has compounded the impact of VRE policy; in an era of low-cost natural gas and increasing levels of state-mandated renewable generation—for example, a 20-percent share of wind and solar by 2020—lack of demand growth means natural gas and new VRE added to meet state mandates compete with existing conventional generation to satisfy a static level of demand.

A review of coal, nuclear, and natural gas retirements to date shows that power plant retirements reflect regional patterns of generation development, state policies, and differences in market structure across regions. However, national patterns also emerge—Figure 3.3 shows that a significant amount of capacity (the highest on record) retired in 2015, coinciding with the MATS compliance deadline (which applied to coal- and oil-fired units across the country) as well as the finalization of the Clean Power Plan rule.

Figure 3.3. Retirements of Coal, Natural Gas, Nuclear, and Other Generating Units, 2002–2022[26]

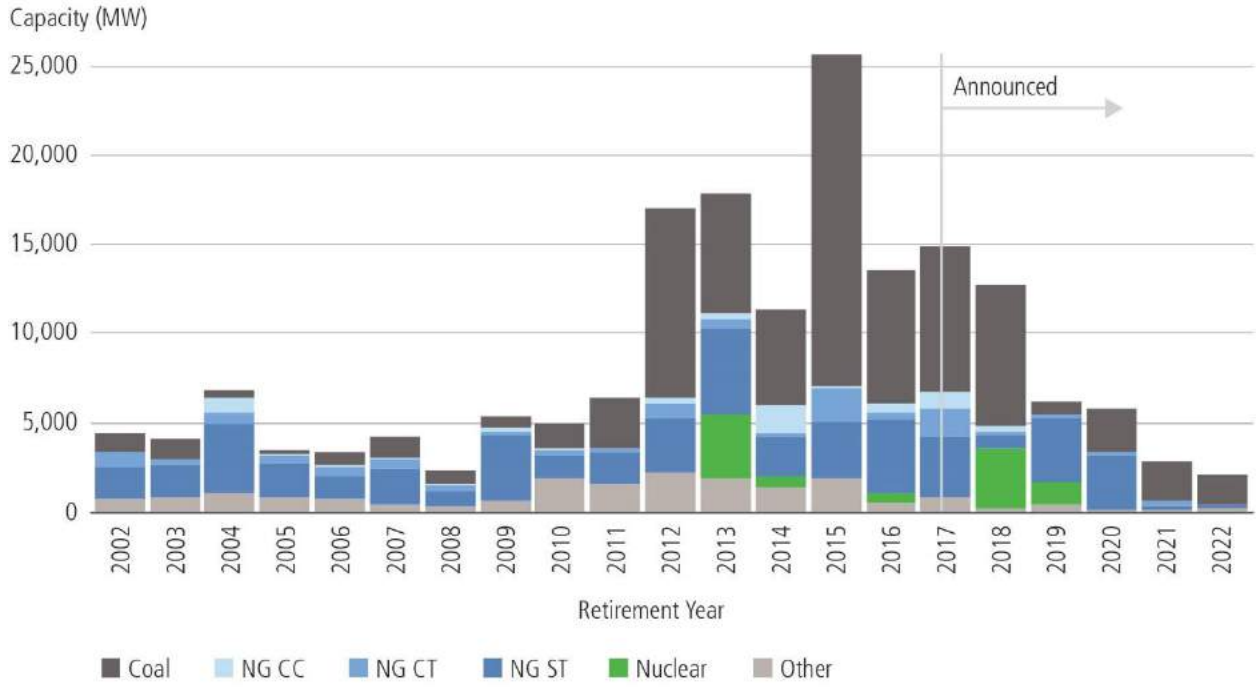
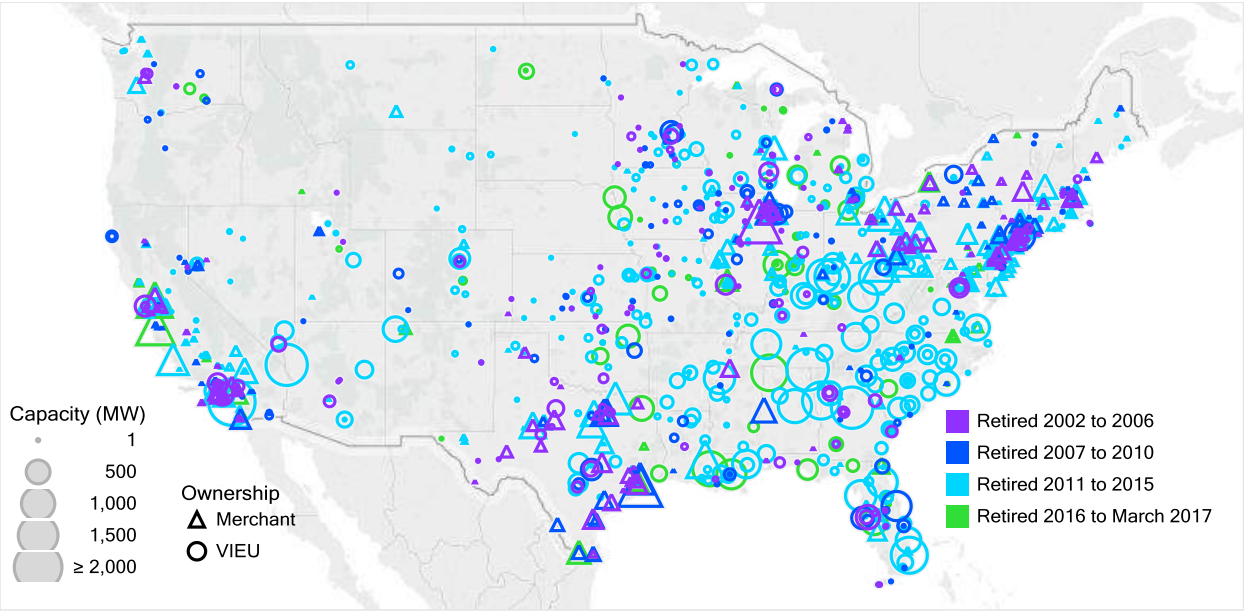


Figure 3.4 highlights retirement trends by ownership type (i.e., merchant vs. VIEU) and time period. Merchant plants accounted for nearly 70 percent of retired capacity during the period 2002–2010 (depicted as triangles below; note how most of the triangles are purple and dark blue). VIEU plants tended to retire later (depicted as circles below; note how most of the circles are light blue and green). The merchant vs. VIEU comparison indicates that market structure is a significant factor in power plant retirements, particularly the timing of retirements.

Figure 3.4. Retirements by Date, Location, Ownership, and Capacity[27]



The data displayed in Figure 3.4 is categorized into four time frames because a variety of economic trends and regulatory events occurred throughout the period 2002–2017:

- During the period 2002–2006 (shown in purple), VIEU plants retired or sold many of their generating assets to third parties through state-initiated processes collectively known as restructuring. During the late 1990s, many states passed legislation initiating restructuring concurrent with the creation of several RTOs and ISOs. The majority of retirements occurring during this period were smaller, older merchant power plants in restructured areas including California, Texas, the Northeast, and the mid-Atlantic region.
- The period 2007–2010 (shown in dark blue) saw early growth of subsidized utility-scale wind generation; the economic recession from 2008 through 2011; and the start of the shale revolution in 2006–2007, with natural gas prices starting a downward trend. Also in this time frame was the 2007 U.S. Supreme Court decision of *Massachusetts v. EPA*, finding that the EPA has the authority to regulate carbon dioxide (CO_2) and other greenhouse gases (GHGs), opening the door to further regulation under the Clean Air Act.[28] Older, less fuel efficient natural gas-fired plants retired early in this period, but the fall in natural gas prices starting in 2009 also began to force the shutdown of smaller, older coal and oil plants in 2009.
- In the period 2011–2015 (shown in light blue), low natural gas prices proved to be a long-lasting rather than a short-term phenomenon. The compliance deadline for MATS converged with tightening pollution limits in sulfur dioxide (SO_2) and nitrogen oxide (NO_X) trading programs. Many of the coal and oil retirements in this period were plants whose owners chose to shut down a plant rather than invest in costly environmental remediation measures. Further, the EPA's final Clean Power Plan rule was finalized during this time.[v] This period had the most power plant retirements, with a marked increase in California, the mid-Atlantic, Midwest, and Southeast. During this period, it also became clear that a portion of the customer electricity demand lost from the recession was not going to reappear in the near term, which meant that electricity demand would not support the higher-cost plants that occupied higher positions on the supply curve.
- In 2016 and going forward (shown in green), power plant retirements are and may continue to be driven by continued economic challenges in the form of market dynamics and compliance costs of regulations, as well as operational pressures from a changing resource mix.

Figure 3.5 shows generation capacity, additions, retirements, announced retirements, and demand response[w] as a percentage of 2002 total installed net summer capacity in each region. The graphic shows that in every region except CAISO+, the proportion of retirements between 2002 and 2016 (in

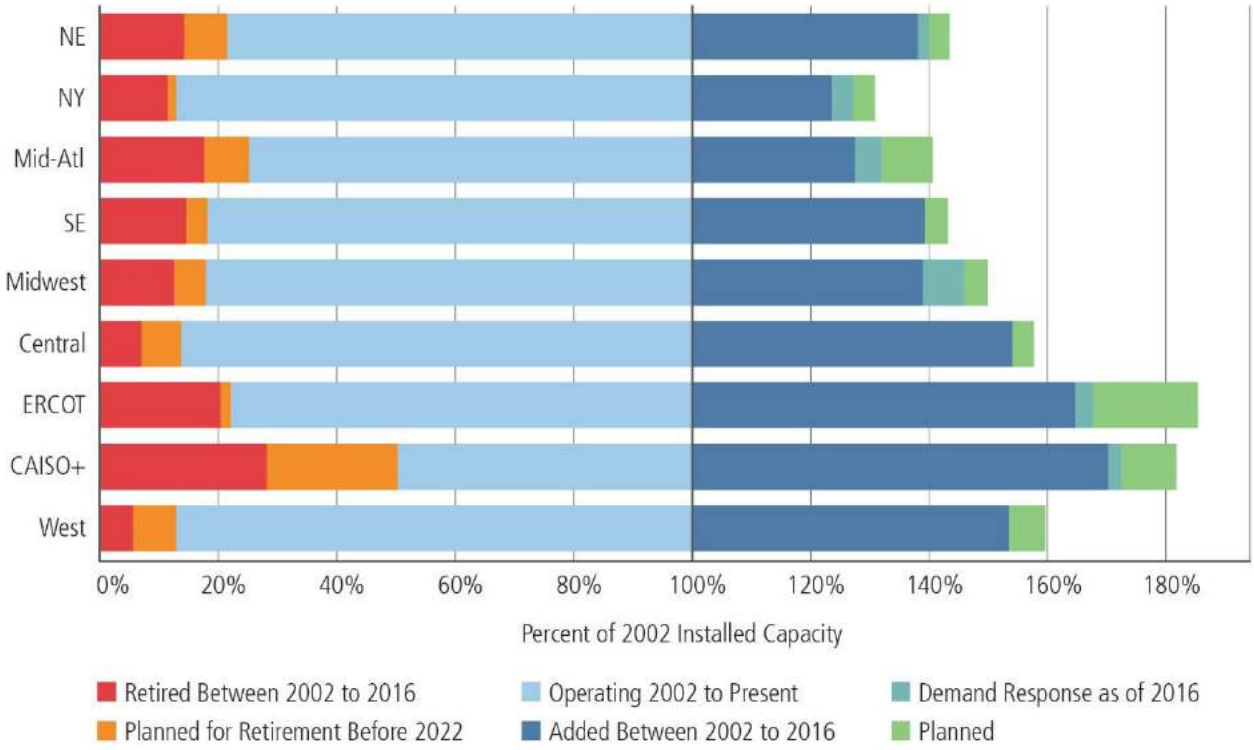
---

[v] Although the Clean Power Plan was later stayed by the Supreme Court, the investment uncertainty around the time of the final rule made reinvestment in coal technology a difficult decision for plant owners. https://www.iaee.org/ej/ejexec/EJ391_ExecSum_Morris.pdf.

[w] Demand response is "a voluntary program offered by independent system operators/regional transmission organizations, local utility service providers, or third parties, which compensate end-use (retail) customers for reducing and/or changing the pattern of their electricity use (load) over a defined period of time, when requested or automatically instructed to do so during periods of high power prices or when the reliability of the grid is threatened." https://energy.gov/epsa/quadrennial-energy-review-second-installment.

orange) is 20 percent or less of the total installed capacity available in 2002 (in red, orange, and light blue). The figure also shows that the amount of new capacity added (dark blue) exceeds the combined amounts of capacity retired (in red) and planned for retirement (in orange) in every region over the study period.[x]

Figure 3.5. Operating Generation Capacity, Additions, Retirements, and Announced Retirements by Region for All Generation Types, January 2002–December 2022[29]

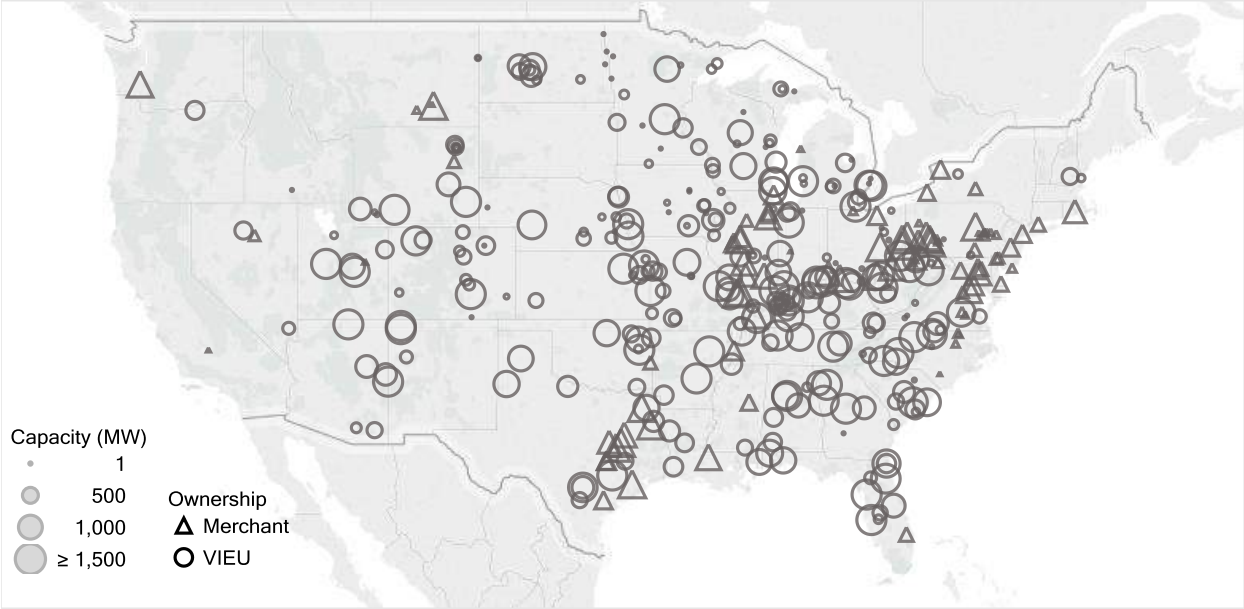


3.1 Coal Plant Retirements

There were approximately 306,000 MW[30] of coal-fired power plants in the United States at the start of 2002 and 270,000 MW[31] at the end of 2016, representing a net retirement of approximately 36,000 MW (about 12 percent) of coal capacity. The remaining fleet of coal-fired generators covers most of the lower 48 states, with the exception of the Northeast, Northwest, and California, as shown in Figure 3.6.

[x] While the graphic includes currently planned additions in EIA's data, this figure does not show *generation* (megawatt-hour) or technology type, and most of planned and added *capacity* (megawatt) comes from new natural gas and VRE sources that do not meet the NERC baseload characteristic discussed earlier.

Figure 3.6. Location of the Existing Coal Fleet

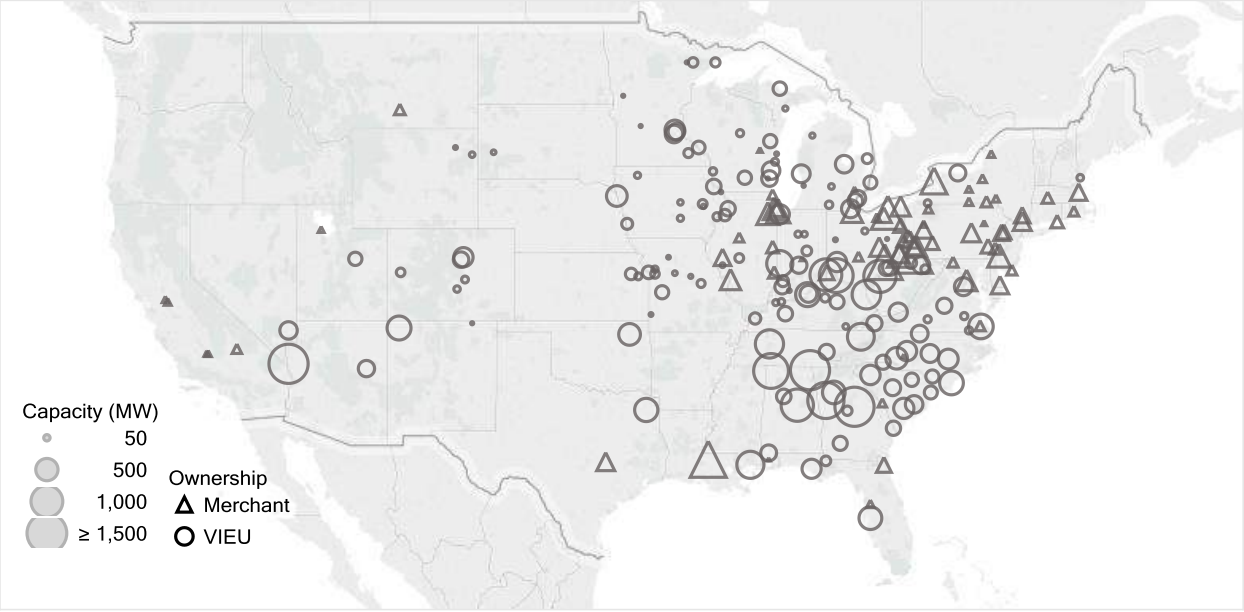


EIA reports that:

> Coal-fired electricity generators accounted for 25% of operating electricity generating capacity in the United States and generated about 30% of U.S. electricity in 2016. Most coal-fired capacity (88%) was built between 1950 and 1990, and the capacity-weighted average age of operating coal facilities is 39 years.[32]

More than 90 percent of the coal consumed in the United States is used for power generation.[33] Coal energy production peaked in 2007 and has been declining since. No new coal plants have been built for domestic utility electricity production since 2014[34] because new coal plants are more expensive to build and operate than natural gas-fired plants.[35] Further, as Figure 3.7 shows, coal retirements span many regions.

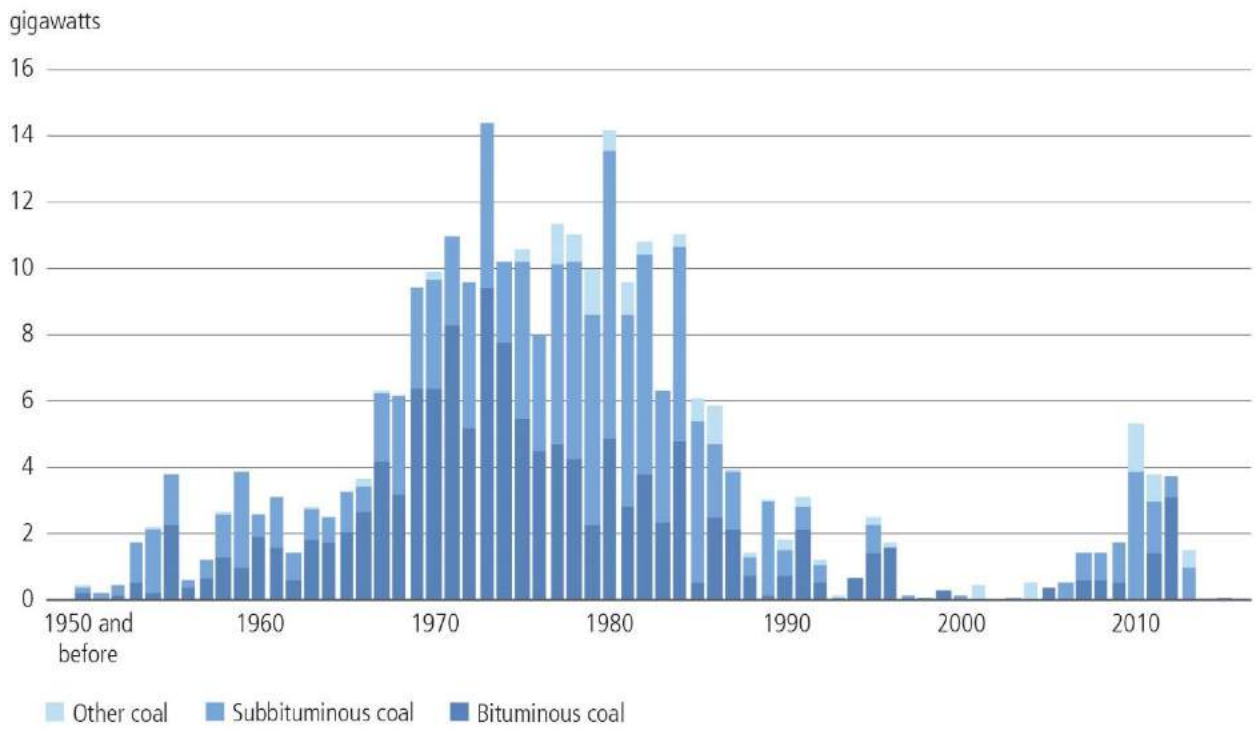
Figure 3.7. Location of Coal Retirements, 2002–2016[36]



Between 2002 and 2016, 531 coal generating units representing approximately 59,000 MW of generation capacity retired from the U.S. generation fleet.

The age of coal plants is an important factor. As Figure 3.8 shows, the vast majority of coal-fired capacity was built before 1990, with the average of the fleet built in the mid to late 1970s.[37] According to the Congressional Research Service, the service life of coal-fired generators reportedly "averages between 35 and 50 years, and varies according to boiler type, maintenance practices, and the type of coal burned, among other factors."[38]

Figure 3.8. U.S. Utility-Scale Coal-Fired Electric Generating Capacity Additions by Coal Type and Initial Operating Year[39] [40]



Between 2002 and 2016, 531 coal generating units representing approximately 59,000 MW of generation capacity retired from the U.S. generation fleet.[41] EIA reported that coal-fired power plants made up more than 80 percent of the 18,000 MW of electric generating capacity that retired in 2015, and that the retiring units "tended to be older and smaller in capacity than the coal generation fleet that continues to operate."[42]

An analysis of coal plant and other data indicates several important trends and attributes:

- About 70 percent of the plants that retired between 2010 and 2016 had a capacity factor of less than 50 percent in the year prior to retirement, and about half of the future planned retirements operated below a 50 percent capacity factor in 2016.[43]
- While none of the units that retired between 2010 and 2016 had significant SO_2 control equipment installed, more than half of the future announced retirements have SO_2 control.
- The average size of planned retirements (380 MW) exceeds the average size of recent retirements (218 MW), indicating that future retirements will be generally larger than previous ones.[44]

- Retired plants are older than the remaining fleet. The coal units that retired in 2015 were mainly built between 1950 and 1970, and the average age of those retired units was 54 years. The remaining coal fleet is relatively younger, with an average age of 38 years in 2016.[45]

In summary, until quite recently, the coal plants that have retired were smaller, older, had higher heat rates, and therefore were dispatched less often and ran at lower capacity factors. Most of the earliest coal retirements were merchant-owned units in the Northeast and Midwest that were more exposed to competition from other generators and fuel types, while VIEU-owned plants in the Southeast and elsewhere experienced a longer period of protection from low market prices.

Workforce Impacts of Coal Plant Retirements and Shifts in Coal Production

Falling demand for coal due to coal plant retirements and capacity factor reductions, a regional shift in coal production, and automation in mining have led to a reduction in coal production jobs. Between 2011 and September 2016, increased mechanization and a shift to western coal resulted in a loss of 36,000 coal mining jobs, of which nearly 90 percent were in Appalachia.[46] As shown in Table 3-1, more than 80 percent of the coal jobs in the United States support electricity production.[47] The oil and gas extraction sector is not subdivided and includes many non-power uses. About 35 percent of the natural gas and roughly one percent of petroleum jobs in the United States support electricity production.[48]

Growth in some energy sectors, such as solar energy deployment, supported new jobs, but they vary regionally and often do not correlate well with concurrent job losses in sectors such as coal mining or power plant operations. Job growth in other energy sectors and regions cannot sufficiently offset job losses in the coal sector without adequate training, salary adjustments, or transition assistance.

Table 3-1. Direct Employment and Income in Industries Related to Electric Power Supply, 2016[49]

Industry Sector/Subsector	Jobs	Percent Related to Electricity Industry	Average Annual Income
Electric power generation	191,000	100%	$113,000
Electric power transmission and distribution	292,000	100%	$99,000
Electric power total	483,000	100%	$104,000
Coal mining[y]	55,000	~80%	$82,000
Oil and gas extraction[z]	377,000	~35% of gas, ~1% of oil	$118,000
Mining and extraction total	432,000	Unknown	$113,000

[y] Includes supporting North American Industry Classification System (NAICS) industry categories.

[z] Includes supporting NAICS industry categories.

Coal Plant Closure Considerations[50]

In September 2016, Ed Malley of *Power Magazine* noted:

The primary recent drivers of coal plant retirement announcements include low natural gas prices and new environmental regulations—especially the Mercury and Air Toxics Standards (MATS), Clean Water Act Section 316(b), and the Coal Combustion Residuals rule. Other contributing factors include more competitive markets and a variety of regional and state-level policies involving renewables and carbon pricing.

Most of the power plants being closed today were built in the 1940s to 1960s, before the Clean Air Act was passed in 1970. Many have minimal air pollution controls, use once-through cooling water, and sluice wet coal ash to ponds. Scrubbers, closed-loop cooling, and dry ash handling are current requirements, or will be phased in over the next few years. Because much of the older capacity tends to be smaller units less than 300 megawatts (MW), which are not economical to retrofit, they are therefore retired. Many closures coincided with the MATS deadlines in 2015 and 2016, at a time when natural gas prices were at historic lows.

Now that the MATS deadlines have passed, additional companies are announcing closures, including Dynegy (5,000 MW) and DTE Energy (2,100 MW). Economics, renewable energy mandates, and reduced demand for electricity are driving these additional closures.

Power plant closure activity began on the East and West Coasts in oil-fired plants because of the high cost of fuel. Closures are now occurring in the coal belts, the Upper Midwest, and the Southeast. There are even some coal-fired plant closures in Western states.

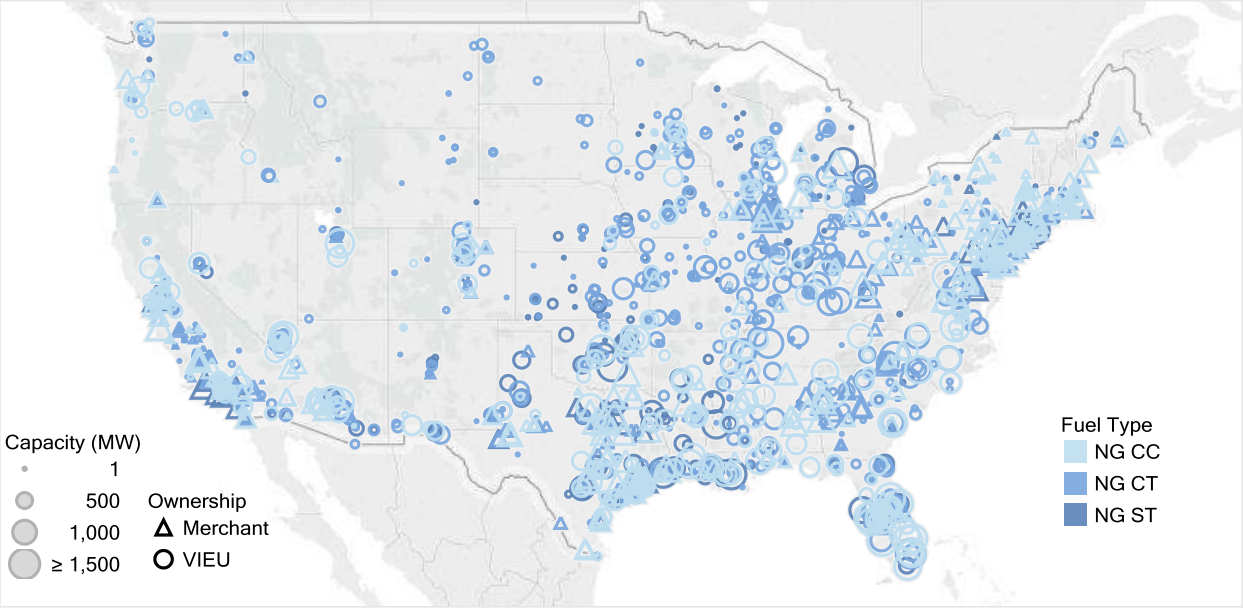
3.2 Natural Gas Plant Retirements

In recent years, the story of natural gas for electricity generation has been one of overall growth rather than decline. However, many natural gas plants have retired since 2002. Natural gas plants are located across the lower 48 states, and are concentrated around major population centers, as shown in Figure 3.9.

According to EIA:

> In 2016, natural gas-fired generators accounted for 42% of the operating electricity generating capacity in the United States. Natural gas provided 34% of total electricity generation in 2016, surpassing coal to become the leading generation source. The increase in natural gas generation since 2005 is primarily a result of the continued cost-competitiveness of natural gas relative to coal.[51]

Figure 3.9. Location of the Existing Natural Gas Fleet[52]



NGCC units accounted for 54 percent of the 447,000 MW of total U.S. natural gas-powered generator capacity in 2016. Combined-cycle generators have been a popular technology choice since the 1990s and made up a large share of the capacity added between 2000 and 2005. Some other types of natural gas-fired technology, such as combustion turbines (CTs, representing about 28 percent of total natural gas-powered generator capacity) and steam turbines (NGSTs, 17 percent), generally only run during hours when electricity demand is high.

The capacity-weighted average age of U.S. natural gas power plants is 22 years, which is less than hydro (64 years), coal (39 years), and nuclear (36 years). The improved efficiency of NGCC plants has led to them being used to a greater degree as baseload generation and increased the overall generation from natural gas. Figure 3.10 shows the initial operating years for the three types of natural gas-fired capacity additions (and their respective share of total natural gas generation in 2016).

Figure 3.10. Capacity Additions of U.S. Utility-Scale Natural Gas-Fired Electricity Generation by Technology Type and Initial Operating Year[53]

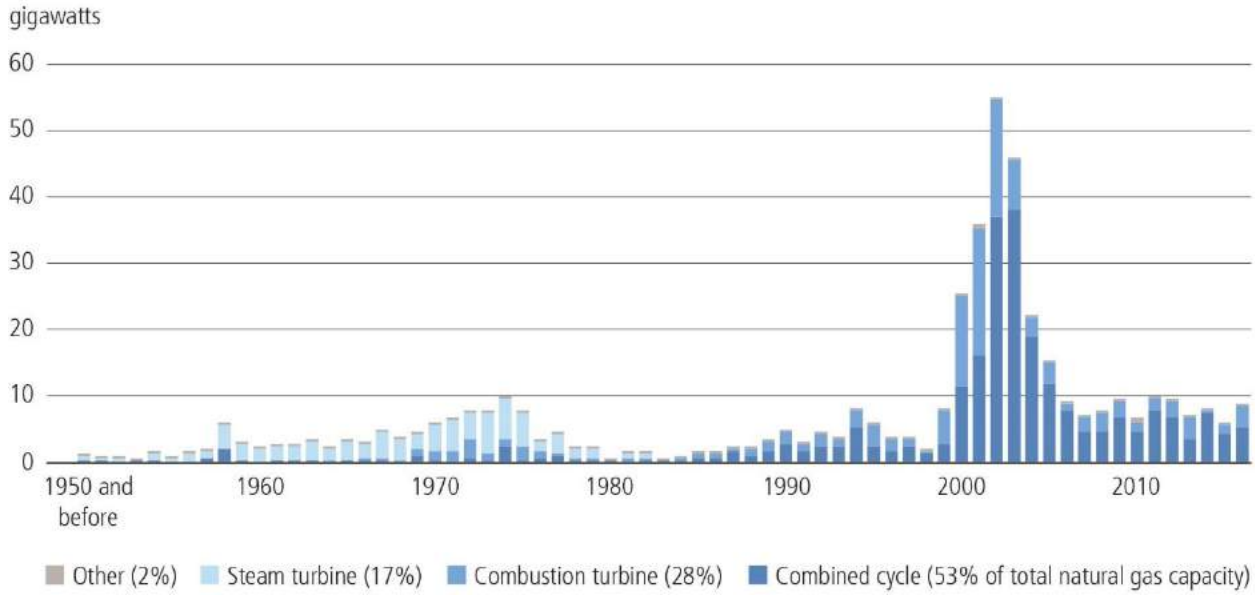
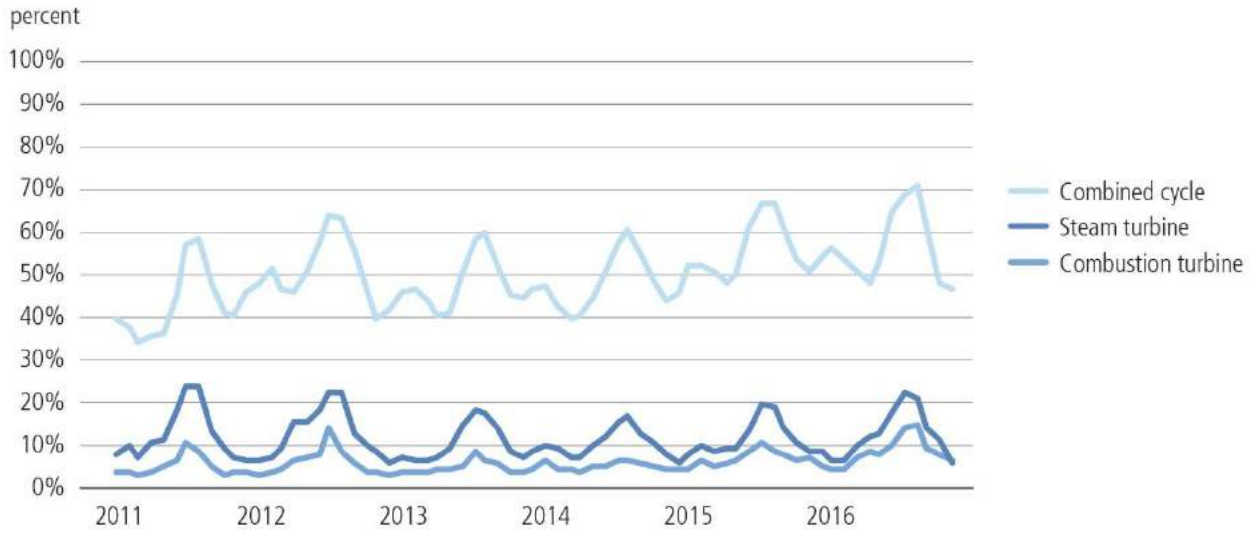


Figure 3.11 shows total natural gas-fired net generation and how the capacity factors of these plants vary by technology over the period 2011–2016. Although NGSTs were originally built principally for baseload use, since the early 2000s, they have been displaced in the dispatch merit order by more efficient NGCC plants designed for greater flexibility. As shown in Figure 3.11, NGST units operate at significantly lower capacity factors than NGCC units.

Figure 3.11. Natural Gas Fleet Capacity Factors[54]



The States of California, Texas, New York, and Florida all had more than 20,000 MW of natural gas-fired capacity at the end of 2016. The National Renewable Energy Laboratory (NREL) reports that, due to the flexibility, efficiency, and cost competitiveness of NGCC power plants, grid operators have been dispatching NGCC plants more frequently as baseload generators.[55] In consequence, the average capacity factor for all NGCC plants has grown from about 40 percent in 2008 to roughly 56 percent in 2016, surpassing that of coal.[56]

Figure 3.12. Location of Natural Gas Retirements[57]

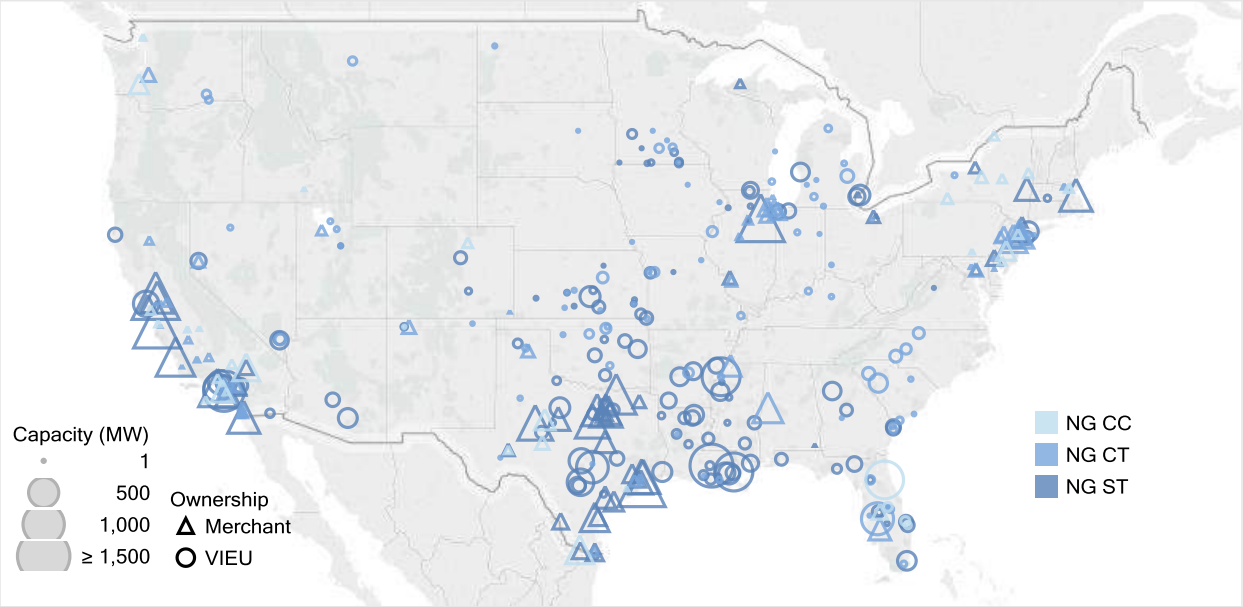
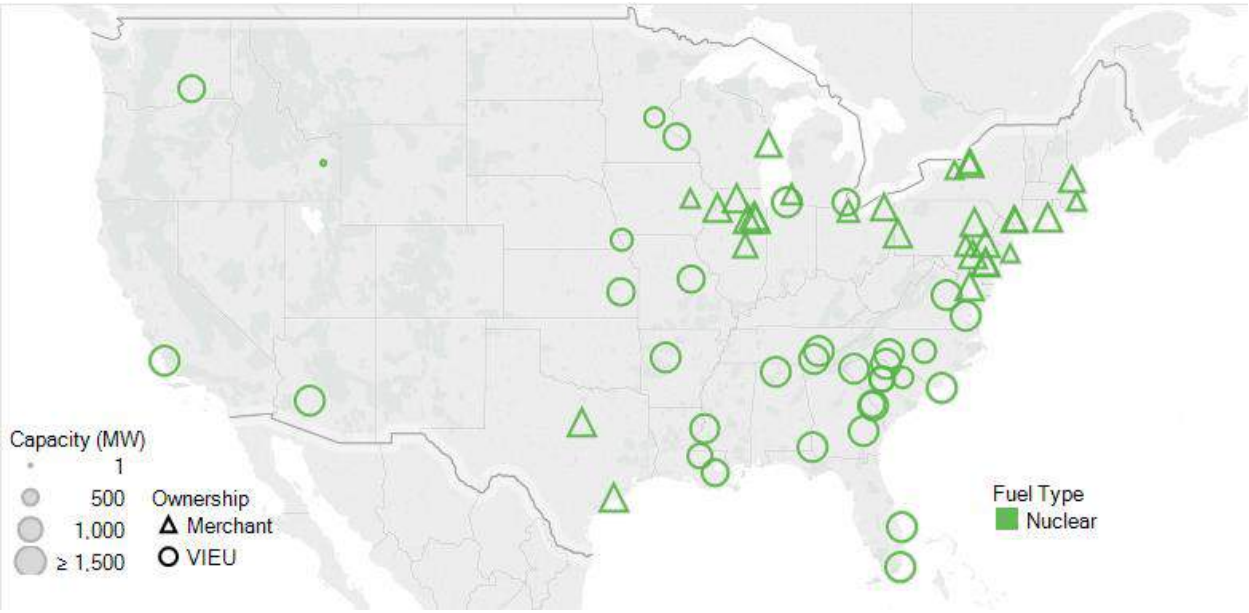


Figure 3.12 shows the retirements of natural gas plants between 2002 and 2016. The ERCOT and CAISO markets have presented difficulties for merchant natural gas (depicted as triangles above; note the concentration of merchant retirements in California and Texas). EIA reported in 2011 that between 2000 and 2010, 33,000 MW of natural gas-fired generation retired (72 percent steam turbines), with an average age at retirement of 48 years and with significantly higher heat rates than the average NGCC.[58]

3.3 Nuclear Plant Retirements

The current operating nuclear power fleet consists of approximately 54,000 MW of generating capacity in regulated markets and approximately 45,000 MW in restructured electricity markets.[59] This represents nine percent of total U.S. utility-scale generation capacity in 2017 and 20 percent of U.S. electric generation in 2016. EIA reports that nuclear plants have higher capacity factors than any other electric generation technology, averaging more than 90 percent (nearly full capacity, full time) over the past five years. The plants refuel every 18 to 24 months.[60]

Figure 3.13. Location of the Existing Nuclear Fleet[61]



The first of these units went online in 1969, and the capacity-weighted average age of the nuclear fleet is 37 years old.[62] Almost all of the operating plants have received approval to conduct at least one capacity uprate; through 2016, these uprates to the existing fleet have contributed more than 7,000 MW of additional nuclear capacity.[63] In addition to capital investments for capacity uprates, nuclear owners make significant capital investments to replace aging components to qualify for license renewal, as well as a suite of additional security and safety investments to comply with new regulations following 9/11 and the Fukushima nuclear accident in 2011.

The United States has the world's largest nuclear reactor fleet. Nuclear power plants contribute about 60 percent of total U.S. emissions-free generation.[64] Located in 60 power plants, the 99 active nuclear reactors provide almost half a million jobs and contribute more than $60 billion to the U.S. GDP.[65] Nuclear energy is viewed as a key strategic asset for the United States, and continued U.S. leadership in the global nuclear energy market has important nonproliferation and safety ramifications to national security interests.[66] As noted recently by Prof. Michael Webber of the University of Texas:

> While the environmental and reliability impacts of the [nuclear plant] closures are well-understood, what many don't realize is that these closures also pose long-term risks to our national security. As the nuclear power industry declines, it discourages the development of our most important anti-proliferation asset: a bunch of smart nuclear scientists and engineers….The loss of expertise from a declining domestic nuclear workforce makes it hard for Americans to conduct the inspections that help keep the world safe from nuclear weapons.[67]

Of the 99 active nuclear units, 51 are owned by VIEUs, which rely on regulated cost-of-service ratemaking. This form of ratemaking provides a stable source of cost recovery assuming reasonably prudent operation and management by the utility. The continued operation of these units depends on decisions by their ratemaking authorities: state regulators; state governments; city councils; cooperative boards; Federal entities; and state regulatory bodies. If these plants become less competitive, authorities may decide to close nuclear units on economic grounds. Authorities can also decide to close nuclear units on grounds other than economics—for example, proximity to the New York City

metropolitan area (36 miles) has been cited as an additional concern in the continued operation of the Indian Point nuclear plant.

Twenty-eight nuclear plants are now merchant plants that were spun off by VIEUs to affiliates under state electric restructuring efforts in the early 2000s. All of these merchant nuclear units operate in centrally-organized wholesale markets. Many of the units were spun off to exploit high locational marginal prices (LMPs) in centrally-organized wholesale electricity markets in the days of high natural gas prices.[aa]

In New York and Illinois, Clean Energy Standards and associated Zero Emission Credits (ZEC) for nuclear plants are being used to help maintain the economic viability and continued operations of nuclear plants, in part to help meet the states' GHG-limiting goals. Modeled after existing RPS and Renewable Energy Certificates (REC), these ZEC payments[68] [69] have been established to direct additional funds to existing nuclear power plants that are no longer cost-competitive. Currently, only New York and Illinois have Clean Energy Standard programs, and these programs are being litigated in the courts.

A recent Idaho National Laboratory report observes that[70]

- There is an industrywide systemic economic and financial challenge to operating nuclear power plants in centrally organized markets;
- Given the confluence of market factors in combination with market structure in centrally organized markets, a significant number of operating nuclear plants have negative cash flow positions today;
- Given current trends, these market factors are unlikely to change significantly over the next five years;
- Retirement of nuclear plants before their operating licenses expire is caused primarily by lower revenues as opposed to higher operating costs, as wholesale electricity prices have precipitously fallen over the last several years;
- The magnitude of the gap between operating revenues and operating costs is in the range of $5–$15 per megawatt-hour (MWh). For a 1,000 MW nuclear unit, approximately every $5/MWh of gap represents about $40 million in annual negative cash flow;
- Without action to enhance revenue (e.g., New York ZEC payments), more nuclear plants will face retirements before the end of their operating license in the future.[71]

Figure 3.14 shows the nuclear reactors that have announced retirement, those that have closed, and those whose closure has been averted by state action. Between 2002 and 2016, 4,666 MW of nuclear generating capacity was announced for retirement, or approximately 4.7 percent of the U.S. total.[72]

[aa] Profits from high wholesale prices are not available to utility cost-of-service regulated units because their revenues are set by state regulators to recover operating costs and provide a target return on invested capital.

Figure 3.14. Location of Nuclear Power Plant Retirements: Closed, Announced, and Averted[73]

As shown in Table 3-2, another eight reactors representing 7,167 MW of nuclear capacity (7.2 percent of U.S. nuclear capacity and 0.6 percent of total U.S. generating capacity[74]) have announced retirement plans since 2016. This does not include seven reactors that averted early retirement through state action.

Table 3-2. Nuclear Plant Retirements, Announced Closures, and Plants Averted by State Action[75] [76] [77]

Closure Year	Reactor	Capacity (MW)	Capacity Factor (2014-2016)	State	Market Type	License Expiration (Licensed Lifetime)	Reason
2013	**Crystal River 3**	860	NA	FL	Vertically Integrated	2016 (40)	failed steam generator replacement
	San Onofre 2 & 3	2,150	NA	CA	Restructured (CAISO) (rate regulated)	2023 / 2024 (40)	failed steam generator replacement
	Kewaunee	566	NA	WI	Restructured (MISO)	2033 (60)	market conditions
2014	**Vermont Yankee**	612	90 (2013 - 2014)	VT	Restructured (ISO-NE)	2032 (60)	market conditions
2016	**Fort Calhoun**	478	62 (2013 - 2015)	NE	Vertically Integrated	2033 (60)	market conditions
2018	**Palisades**	787	93	MI	Restructured (MISO)	2031 (60)	market conditions (despite being under PPA through 2022)
2019	**Pilgrim**	678	91	MA	Restructured (ISO-NE)	2032 (60)	market conditions
	Oyster Creek	608	92	NJ	Restructured (PJM)	2029 (60)	state policy / avoid large capital costs associated with building a cooling tower
	Three Mile Island 1	803	99	PA	Restructured (PJM)	2034 (60)	market conditions
2020-2021	**Indian Point 2 & 3**	2,051	86 / 94	NY	Restructured (NYISO)	2013 / 2015 (40)	state policy
2024-2025	**Diablo Canyon 1 & 2**	2,240	92 / 92	CA	Restructured (CAISO) (rate regulated)	2024 / 2025 (40)	state policy / market conditions
Included in State CES	**FitzPatrick**	853	86	NY	Restructured (NYISO)	2034 (60)	market conditions
	Ginna	582	95	NY	Restructured (NYISO)	2029 (60)	market conditions
	Nine Mile Point 1 & 2	1,924	92 / 93	NY	Restructured (NYISO)	2029 / 2046 (60)	market conditions
	Clinton	1,065	95	IL	Restructured (MISO)	2026 (40)	market conditions
	Quad Cities 1 & 2	1,819	100 / 95	IL	Restructured (PJM)	2032 (60)	market conditions

As Table 3-2 shows, Indian Point is the only announced closure that lists state policy as the sole reason for retirement. 12 of the 16 plant closure announcements refer to unfavorable market conditions as the driver for plant retirement. Four of the five nuclear power plants (six reactors) that have shut down since 2013 were single-unit plants. Of the 11 nuclear power plants (15 reactors) that have announced

intentions to close—including the five plants (seven reactors) in New York and Illinois that will remain open as a result of state action—four are dual-unit plants and seven are single-unit plants.

Table 3-3 shows the range of nuclear plant average costs in 2016 (in $/MWh). The data indicates that single-unit plants are more costly than multi-unit plants, and that operators who own only one nuclear plant have higher costs than those who own a fleet of plants. This is largely because some operating costs, such as security, do not scale linearly with plant size. As a result, single-unit or smaller plants are more expensive, and thus more likely to be retired prior to the end of their license terms.

Table 3-3. Average Nuclear Costs by Plant Size and Operator Type, 2016[78]

2016 Cost Summary ($/MWh)

Category	Number of Plants/Sites	Fuel	Capital	Operating	Total Operating (Fuel + Operating)	Total Generation (Fuel+Capital+ Operating)
All U.S.	60*	6.76	6.82	20.42	27.17	34.00
Plant Size						
Single Unit	25	6.77	8.37	25.83	32.60	40.97
Multi Unit	35	6.75	6.34	18.75	25.50	31.85
Operator						
Single	12	7.18	8.51	21.05	28.23	36.74
Fleet	48	6.63	6.33	20.24	26.87	33.20

*Costs exclude shutdown plants.

A nuclear plant fully exposed to low wholesale energy prices can earn additional revenues in three other ways: it may receive capacity payments if it is located in a centrally-organized market with a capacity payment scheme (New York, New England, MISO, and PJM), it can earn revenues for providing reliability products such as frequency response,[bb] or it may receive ZEC or similar subsidy payments from its host state.

If a nuclear plant is owned by a VIEU, its regulators may allow it to continue collecting capital recovery from its ratepayers even though the utility is effectively paying more to run the nuclear unit than it would cost to buy the same energy and capacity under a bilateral contract or spot market purchases. However, as long as natural gas prices stay low and there is an oversupply of energy in many hours, the typical nuclear plant may not be profitable. Bloomberg New Energy Finance estimates that 34 of the Nation's 60 nuclear plants are losing money.[79]

Not all nuclear power plants close due to unfavorable economics alone. For example, Pacific Gas and Electric (PG&E) has decided to shut down its dual-unit Diablo canyon plant in California due to several factors, including changes in state policy (California is moving to 50 percent RPS by 2040), new environmental regulations (replace once-through cooling system at an estimated cost of $8–$12 billion), local opposition to the NRC relicensing extension application, and uncertainty about future loads to be

[bb] See Section 4.1.1 for the technical definition of frequency.

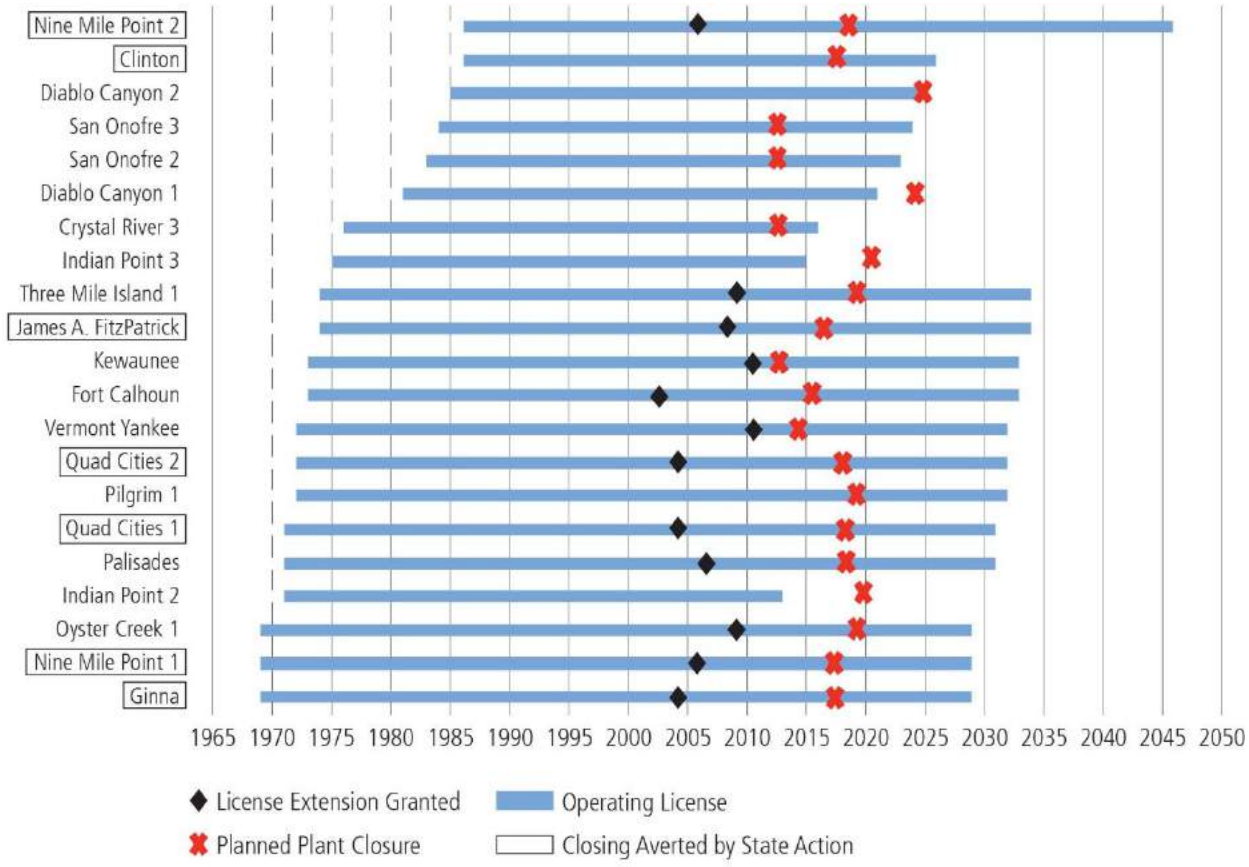
served by the regulated utility (specifically, community choice aggregation, which allows for third-party retail suppliers).

The NRC's nuclear relicensing program is another factor affecting the future of U.S. nuclear power generation. The NRC issues initial reactor operating licenses covering a 40-year term, but those licenses have been routinely extended. Of the 99 operating nuclear reactors in the United States, 84 have been approved to operate for 60 years, while another nine are currently under review.[80] However, based on the current and potential license extensions to 60 years, only three units (Comanche Peak Unit 2 and Watts Bar Units 1 and 2) will still be operating after 2050, unless subsequent license extensions—out to 80 years—are submitted and approved. Two utilities have already announced plans to seek subsequent license renewal for two plants.[81]

Extended nuclear plant operations often entail major capital upgrades of plant equipment. According to DOE's Light Water Reactor Sustainability Program, the required capital costs for equipment upgrades drive the total cost for extension; these costs vary by plant. DOE estimates that it requires $500 million to $1 billion per plant of additional capital expenditures to operate a plant for an additional 20 years.[82] These routine maintenance and equipment replacements would be required in this time frame regardless of the licensing process.[83]

Figure 3.15 shows a comparison of license duration to planned closure date. As depicted, most decisions to retire have come well before the expiration of the plant's license. A few of the plants shown in the figure (indicated by a box around the plant name) were able to avert closure as a result of state actions.

Figure 3.15. Nuclear Plant Retirements Compared to NRC Plant Operating License Terms[84 85 86]



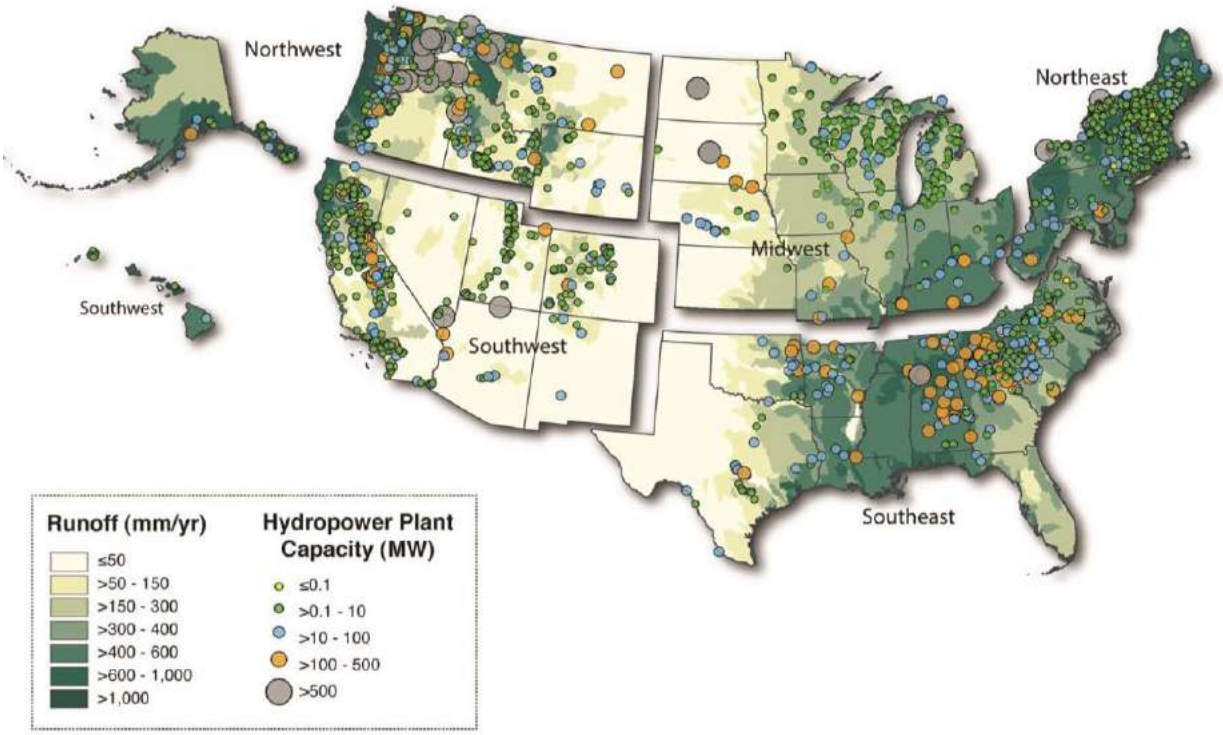
3.4 Hydropower Retirements and Repowering

In 2015, the U.S. hydropower fleet included 2,198 active power generation plants with a total capacity of 79,600 MW and 42 pumped-storage hydropower plants totaling 21,600 MW.[87] As of 2016, hydropower accounted for more than six percent of net U.S. power sector electricity generation, nearly nine percent of U.S. electric generating capacity, and 97 percent of U.S. utility-scale electrical storage capacity.[88] Hydropower is currently the largest source of renewable generation, providing nearly 44 percent of all U.S. renewable energy in 2016.[89] [90]

Half of U.S. hydro capacity is located in the States of Washington, California, and Oregon. The hydropower fleet is the oldest in the U.S. -- as stated in QER 1.2, "About half the U.S. hydroelectric fleet is over 50 years old since many large dams were built between the 1940s and 1960s,"[91] and the average hydroelectric facility has been operating for 64 years. However, with routine maintenance and refurbishment of turbines and electrical equipment, the expected life of a hydropower facility is likely to be 100 years or more.[92]

Hydropower is a varied resource. Forty-eight states (see Figure 3.16) have hydropower facilities, led by California, Oregon, and Washington. Ownership of hydropower plants is highly diverse, split across a wide range of private and public entities. Approximately 50 percent of hydropower capacity is owned by the Federal Government—the three main Federal agencies authorized by Congress to own and operate hydropower plants are the U.S. Army Corps of Engineers, the Bureau of Reclamation, and the Tennessee Valley Authority. Other public ownership includes public utility districts, irrigation districts, states, and rural cooperatives, whose hydropower resources consist of about 24 percent of the total installed capacity. Private owners—including VIEUs, merchant power producers, and industrial companies—control the remaining 25 percent of total installed capacity.[93]

Figure 3.16. Hydropower Plants in the United States by Capacity and Average Annual Runoff[94]



While some hydropower plants are operated as baseload resources, many also support the dynamic behavior of grid operations by offering a full range of ancillary services, including load following, spinning and non-spinning reserve, and voltage and frequency support. This flexibility has historically complimented other traditional forms of baseload generation, such as coal and nuclear. The majority of hydropower capacity is operated as either peaking or run-of-river. Peaking plants shift or delay water releases used for generation to higher value times of the day, contingent on a project's storage capability and the regulatory requirements governing its operation. While peaking plants have usable storage from a project's reservoir, run-of-river facilities have little to no ability to store water, and generation only changes based on the natural variability of flows, though even these types of facilities are capable of providing a number of ERS. In some regions, hydropower assets have been operated in more flexible modes in recent years as VRE penetration increases.[95]

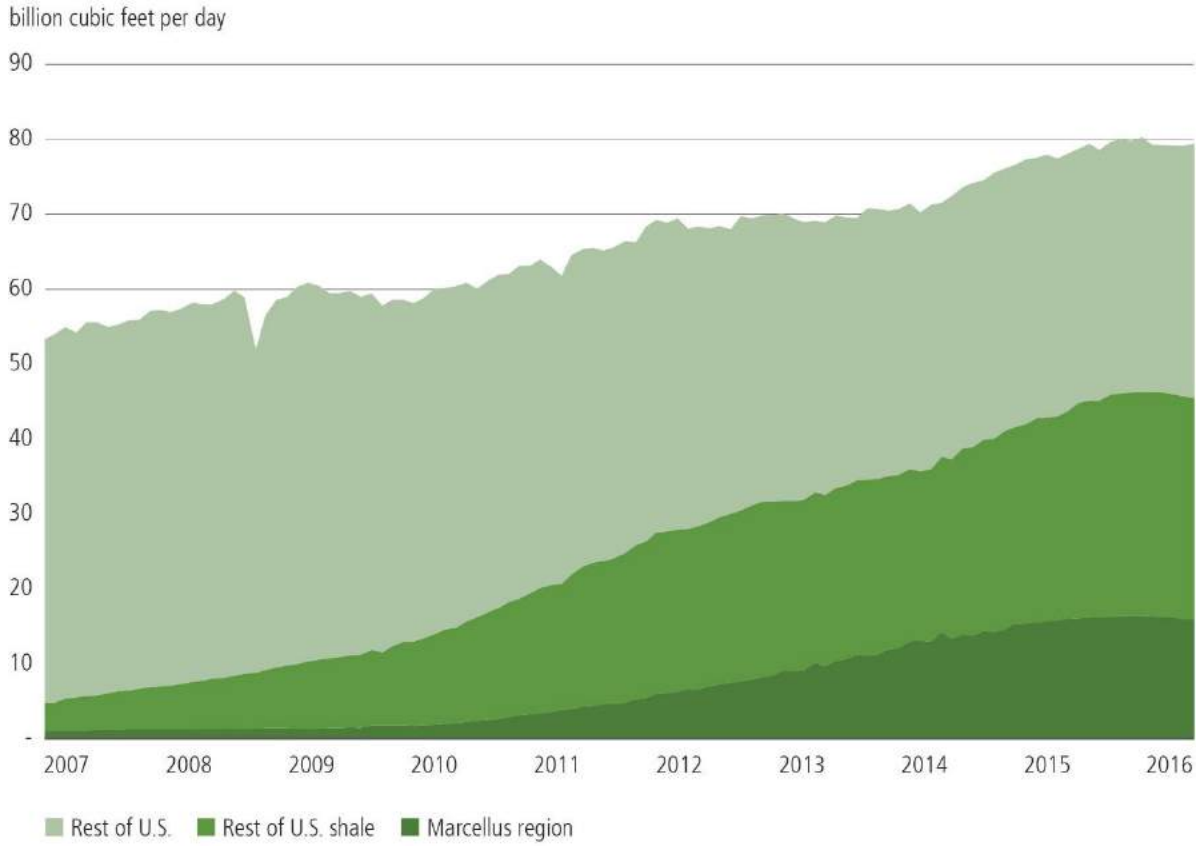
At the beginning of 2011, hydropower plants comprised 24 of the 25 oldest operating power facilities in the United States, with 72 percent of facilities older than 60 years.[96] However, significant capital investment toward modernizing and upgrading the existing fleet is consistently taking place to maintain reliability and, at times, uprate the capacity of existing facilities. From 2007 to 2016, the industry invested at least $8.7 billion in refurbishments, replacements, and upgrades to hydropower plants at 143 hydropower facilities, including $1.2 billion and 34 plants in 2016 alone.[97] This often includes equipment upgrades, turbine efficiency improvements, and modifications that ensure environmental protection and mitigation as part of relicensing terms. Most of the recent hydropower capacity additions in the United States have come from unit upgrades or additions to existing projects.[98] While FERC does receive appropriations from Congress to defray operating costs, these appropriations are recovered completely through annual charges and administrative fees.[99]

EIA public reports indicate that 1,376 MW (of the total 79,985 MW of U.S. hydroelectric capacity) retired between 2002 and 2017—in most cases as part of repowering projects in which the retired turbine generators were replaced with new equipment. Fifty-two relatively small-scale hydroelectric generators representing 283 MW of generation capacity were retired without replacement.[100]

3.5 Falling Natural Gas Prices

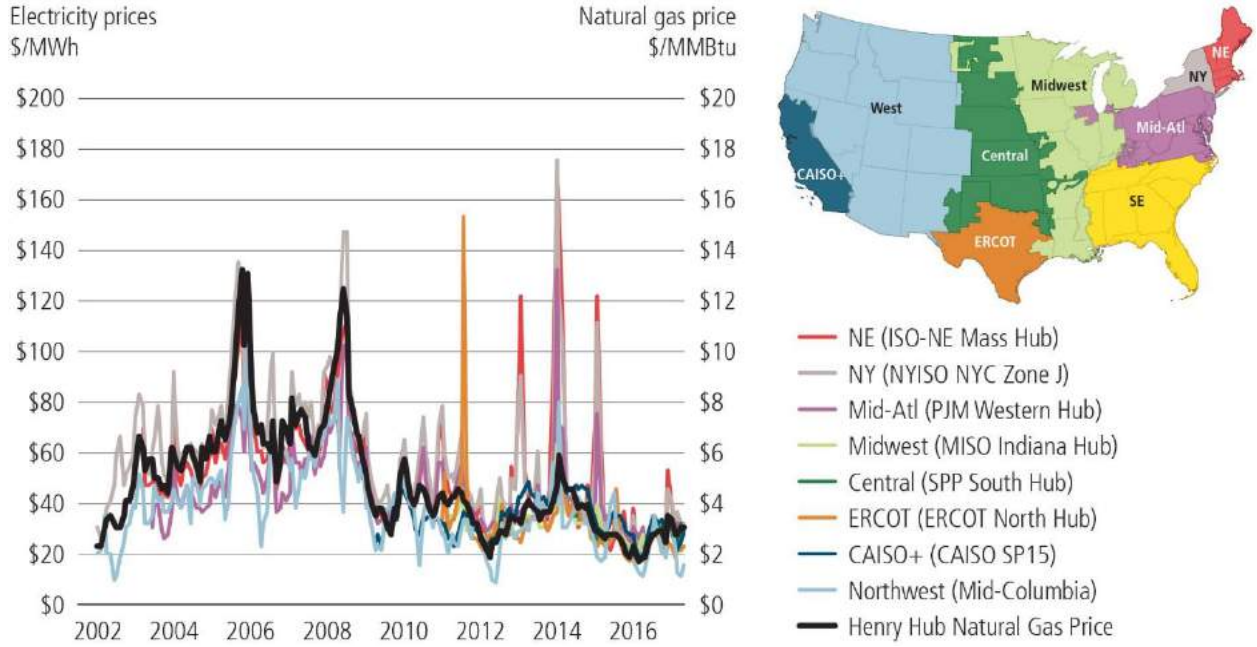
Shale gas development has significantly expanded the availability of natural gas and lowered its cost across the United States and the world.[101] Before the widespread use of horizontal drilling techniques in the past decade, U.S. natural gas prices averaged more than $7 per million British thermal unit (MMBtu) between 2003 and 2008, and approached $14/MMBtu in several short periods (including in 2005 after Hurricanes Katrina and Rita reduced production and delivery from Gulf of Mexico sources).[102] Hydraulic fracturing practices spread and made previously inaccessible gas sources economic, causing natural gas prices to fall, averaging less than $3.20/MMBtu between 2012 and 2016.[103]

Figure 3.17. Conventional and Shale Natural Gas Production, 2007–2016[104]



Wholesale electricity prices generally tracked natural gas prices for the study period, as shown in Figure 3.18. This is likely because gas-fired mid-merit and peaker power plants have been the marginal generators following load in many hours of the day, and their short-run marginal costs are driven by natural gas prices.[105] Thus, natural gas plants and gas prices have been the largest single driver of spot electricity prices.

Figure 3.18. Wholesale Day-Ahead Electricity Prices vs. Henry Hub Natural Gas Price (Monthly Average)[106]



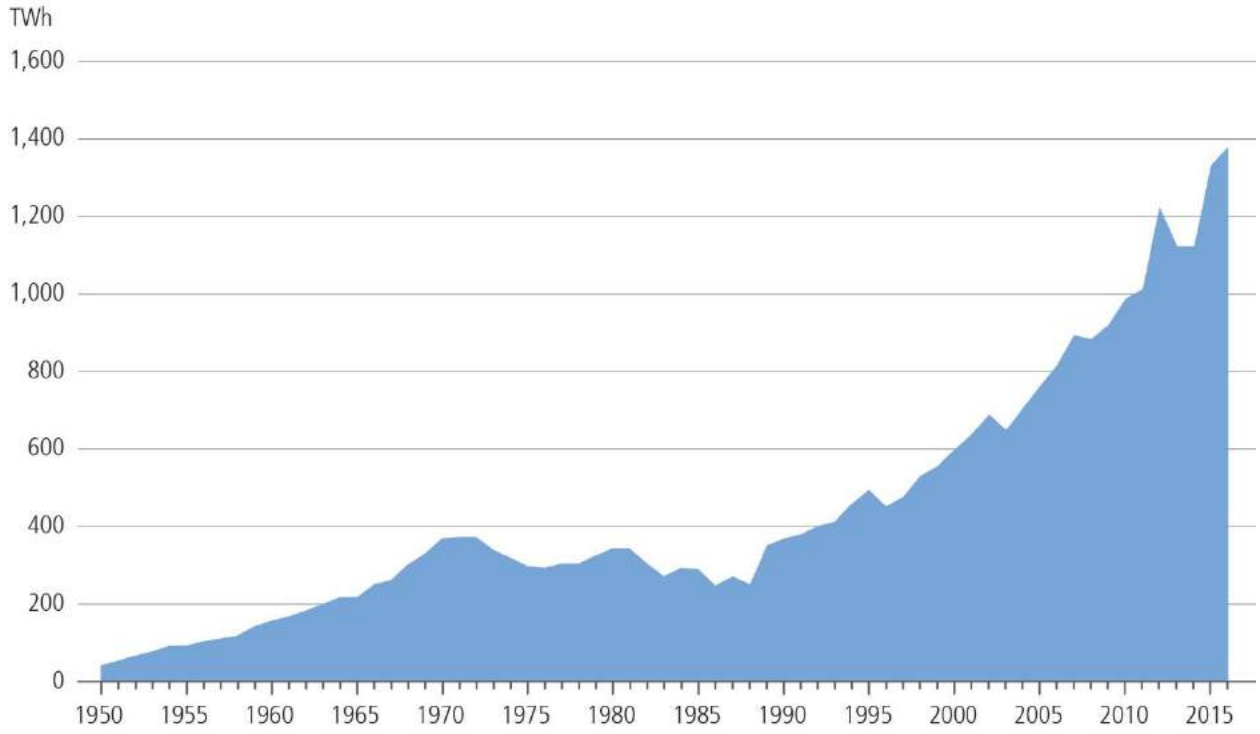
The price of natural gas is a key factor in the prices generators offer in the bid-based RTO/ISO wholesale electricity markets. It is also a factor in the prices set in bilateral power sales, including in the non-RTO/ISO regions such as the Southeast. Consequently, wholesale and bilateral transaction prices are often driven by natural gas prices across large parts of the U.S. power market.[cc] On one hand, wholesale electricity prices have become increasingly exposed to potential volatility in natural gas delivered prices. On the other hand, the Nation has realized significant economic benefits from the shale revolution—falling natural gas prices between 2007 and 2013 generated an estimated net economic benefit of $48 billion per year over this period.[107]

Natural gas-fired generation has grown nearly continuously since the late 1980s (see Figure 3.19) for several key reasons. These plants have low capital costs and are, in general, relatively less expensive than some competing technologies.[108] They are also much less land-intensive than many other types of generation, and thus often can be more easily sited in urban areas near electric demand.[109] Similarly, natural gas pipelines can be built more quickly than electric transmission lines (in most states) because they have a comparatively streamlined permitting process, which often has made it easier for a plant developer to build a new gas-fired plant near a large electric load than to build a power plant farther away and transmit its electricity to large load centers by wire.[dd]

[cc] When natural gas prices were high, this situation yielded large profits to the then lower-cost coal and nuclear power producers. However, as gas prices and therefore wholesale and bilateral contract power prices have declined, the situation has reversed, and many coal and nuclear plants have been losing money.

[dd] Interstate natural gas pipelines can often be built more quickly than transmission lines because the pipeline owners, once granted a FERC-issued certificate of public convenience and necessity, have eminent domain power under section 7(h) of the Natural Gas Act and the procedures set forth under the Federal Rules of Civil Procedure (Rule 71A). By contrast, electric transmission developers are dependent on states to grant eminent domain authorization.

Figure 3.19. Total Annual U.S. Natural Gas Generation, 1950–2016[110]



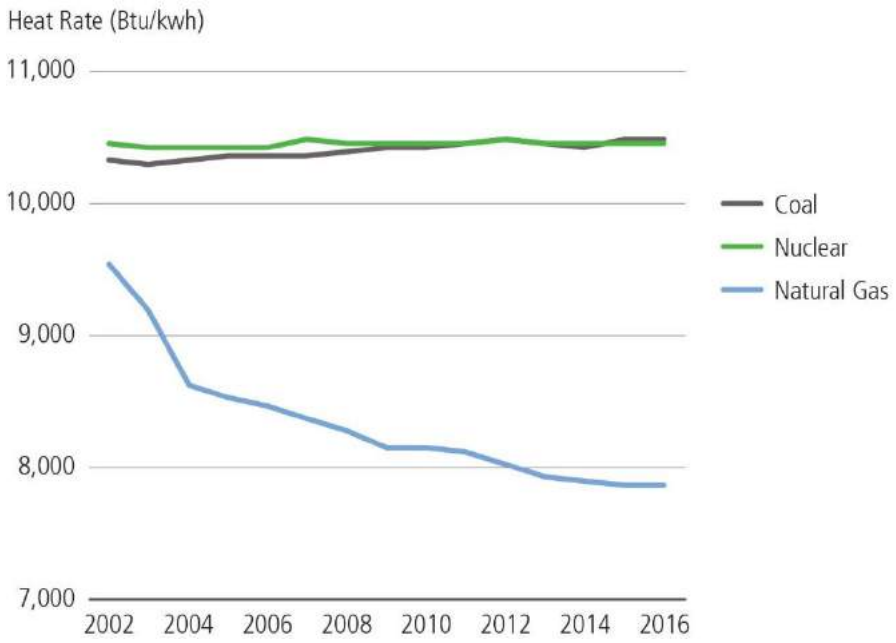
The two main types of natural gas generators (NGCCs and CTs) offer distinct operational advantages. NGCC generators are very efficient and have significantly higher capacity factors than single[111] (simple) cycle natural gas CTs, which contribute primarily to meeting peak load and may only operate for a few hours a year.[112] A CT's short start-up time and fast ramp rate make it the most responsive component for ensuring enough capacity exists to meet demand during the highest-peak demand hours of the year and help maintain grid reliability, absent affordable grid-scale storage. For this reason, CT capacity factors are usually low[ee] (generally below 10 percent).[113] CTs can go from cold start-up to 100 percent output in seven to 11 minutes; in contrast, coal-fired units ramp on the order of hours, and doing so incurs increased operations and maintenance costs.[114] NGCC ramp rates fall somewhere in between, and some NGCC units can ramp to full-rated power in less than 30 minutes.[115] This flexibility makes NGCCs and CTs useful in complementing VRE because their flexibility allows these plants to match changes in solar or wind output.

Until recently, most NGCC units were used for intermediate and peak loads rather than baseload. However, because natural gas prices have been low for a sustained period, and because NGCC plants retain some of the flexible characteristics of CTs and operate at a higher efficiency and lower cost, these units often are now used for baseload power. As a result, some coal plants have been pushed higher on the merit order, which reduces their average capacity factors, negatively impacts their economics, and can ultimately lead to retirements.

[ee] Some states rely on CTs more regularly than other locations; most notably, Texas, Louisiana, Wyoming, New Hampshire, Maine, and Rhode Island all have CT capacity factors greater than 20 percent. https://energy.gov/epsa/downloads/electricity-generation-baseline-report.

On top of low fuel prices, natural gas-fired power plants have become more fuel efficient over the study period. Figure 3.20 shows how the fuel energy usage per unit of electricity generation of the fleet of generators has changed from 2002 to 2016 for each fuel type. The natural gas fleet has become increasingly efficient (i.e., achieved a lower heat rate) as old steam electric plants have retired and many new, highly efficient NGCC plants have been built and operated at high utilization rates.[116]

Figure 3.20. Heat Rates for Coal, Nuclear, and Natural Gas, 2002–2016[117]



3.6 Environmental Regulations

A suite of environmental regulations affecting the electricity generation sector had implementation deadlines between 2011 and 2021, stemming from statutes enacted between 1970 and 1990. These regulations have had disparate effects on the costs of various power generation technologies. While the cost of environmental regulations has been significant for coal-fired power plants in particular, the evidence reviewed below indicates that regulations were not the sole cause of observed coal retirements, but were certainly a contributing factor. Following are two key takeaways:

1. Timing suggests that regulations had an impact on retirements. Of the 59,392 MW of coal-fired power plants that retired between 2002 and 2016, approximately 48,800 MW or 82 percent of that capacity retired in the period 2012–2016, when significant environmental regulations would have affected the invest-or-retire decision. This left 270,000 MW of coal-fired capacity on the grid (down from 315,000 MW in 2002), which produced 30 percent[118] of total 2016 U.S. electricity output (down from 50 percent in 2002).
2. Many of the coal plants that retired were no longer “baseload.” Due to low natural gas prices and abundant natural gas generation capacity additions, most of the coal plants that retired between 2011 and 2015 (when the environmental regulations took effect) had not been operating in their intended baseload fashion for several years.[119]

All nuclear power plants are affected by regulations pertaining to safety, security, and upgrades required for license renewal. In addition, nuclear plants are affected by the Cooling Water Intake Rule, and some announced closures have cited, among other reasons, state requirements to modify cooling water systems as a reason for retirement.[120] [121] Hydropower plants are also affected by other environmental regulations and unique licensing processes.

Table 3-4 summarizes major environmental regulations finalized after 2011 affecting coal, natural gas, and nuclear power plants.

Table 3-4. Major Environmental Regulations Related to Coal, Natural Gas, and Nuclear Generation

Name	Year Finalized[ff]	Year (s) Implemented	Authorizing Statute[gg]	Major Provisions	Generation Sources Affected
Cooling Water Intake Rule[122]	2001 (Phase 1), 2003 (revised Phase 1), 2014 (Phase II)	Phase II: 2014–2018[123]	Clean Water Act	• Promulgated under 316(b) of the Clean Water Act. New sources regulated under Phase I and existing sources regulated under Phase II. • States consider requirements for power plants on a case-by-case basis.[124] • Requires controls to reduce mortality to fish and other aquatic organisms.	Coal Gas Nuclear
Cross-State Air Pollution Rule[125]	2011	Phase 1: 2015 Phase 2: 2017	Clean Air Act	• The Cross-State Air Pollution Rule replaced the Clean Air Interstate Rule starting on January 1, 2015, and requires states to reduce power plant emissions of SO_2 and NOx that contribute to ozone emissions and fine particle pollution in other states.[126]	Coal Gas
Steam Electric Effluent Limitations Guidelines[127]	1974; policy updates in 1977, 1978, 1980, 1982, and 2015	1982; 2015 update is stayed while EPA reviews rule	40 CFR 423	• Established limitations on the discharge of toxic and other chemical pollutants and thermal discharges from existing and new steam electric power plants, as well as pretreatment standards. • The 2015 update sets the first Federal limits on levels of toxic metals that can be discharged.	Coal Gas
New Source Review[hh]	1980; policy updates in 1996 and 2002	1980; 2002 updates under court challenge	Clean Air Act	• Affects stationary sources of air pollutants. Requires that a new or modified power plant obtain a pre-construction permit to ensure, among other things, that modern pollution control equipment is installed. • Requirements differ depending on whether or not the plant is located in an area that	Coal Gas

[ff] Dates shown here reflect the date of publication in the *Federal Register*.

[gg] For regulations only.

[hh] The New Source Review (NSR) program affects most new and modified power plants and manufacturing facilities. Determining when a facility is making a modification that triggers NSR has been a subject of debate. Attempts have been made over decades to update NSR—the latest in 2002. More information can be found at: http://www.rff.org/research/publications/epa-s-new-source-review-program-time-reform and http://www.aei.org/publication/making-sense-of-new-source-review/

				meets the requirements under the National Ambient Air Quality Standards.	
Mercury and Air Toxics Standards[128]	2012	2015–2016	Clean Air Act	• Establishes emissions limits for mercury, arsenic, acid gases, and other toxic pollutants from coal- and oil-fired power plants.[129] • Utilities had until April 2015 to comply with the standards with many plants receiving a 1-year extension.	Coal
Coal Combustion Residuals Rule[130]	2015	2015-2018[ii]	Resource Conservation and Recovery Act	• Addresses groundwater contamination risks from coal combustion residuals (i.e., "coal ash") disposal in unlined landfills and surface impoundments by establishing national standards for disposal.	Coal
Regional Haze Rule	1999; policy revisions in 2017	Revised state plans due in 2021	Clean Air Act	• Requires states to develop long-term strategies, including enforceable measures to improve visibility in 156 national parks and wilderness areas. • Aims at returning visibility to natural conditions by 2064.	Coal
Carbon Pollution Standards and Clean Power Plan[131]	2015	Under EPA review	Clean Air Act	• Carbon Pollution Standards established CO_2 emission standards for new fossil fuel-fired generators under Clean Air Act section 111(b). • The Clean Power Plan, promulgated under section 111(d) of the Clean Air Act, establishes CO_2 emission standards for existing power plants.	Coal Gas

The collective impact of this suite of regulations required owners to weigh the cost implications of a variety of compliance options for their plants, and to also look closely at whether their market prospects (expected production costs and capital needs, relative coal and natural gas fuel costs, competition from other generators, technology availability, and customer demand levels) or regulatory regime would allow recovery of those costs in future operating years. Most of these rules were litigated and delayed—the Clean Power Plan, for example, currently is stayed and ultimately may be rescinded, but uncertainty about its implementation nonetheless affected plant owners' compliance and retirement planning.

In 2011, looking at then-current energy market prospects and fuel prices, it appeared that many power plants would be affected by these environmental regulations. Fitch Ratings estimated that 51,000 MW of coal units (smaller than 200 MW each, with a capacity-weighted average age of nearly 50 years) were at risk for retirement, particularly those operating in restructured electricity markets with no recourse to regulated cost recovery.[132]

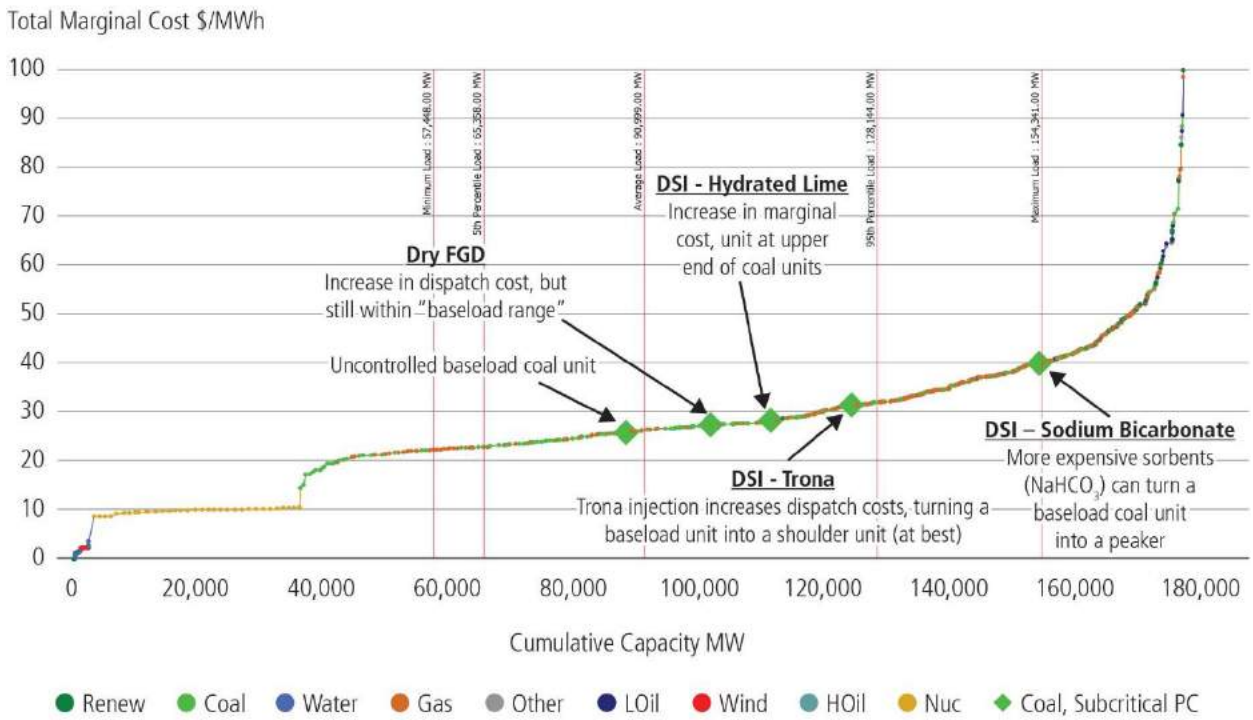
In 2011 and 2012, electric industry projections of likely regulation-induced retirements that focused on the many unknowns associated with pending environmental regulations sometimes showed a very large number of retirements. These unknowns included how stringent environment remediation requirements would be; what remediation technology and strategies might satisfy those requirements; how close together the compliance deadlines would fall; and the implications for regional reliability,

[ii] The Water Infrastructure Improvements for the Nation Act S.612, passed in December 2016, authorizes states to create their own permitting programs for coal combustion residuals disposal, subject to EPA approval. The act specifies that states may adopt alternative standards that are "at least as protective" as national standards. EPA has not yet issued guidelines or regulations by which state permitting programs can be approved.

energy production costs, and retail energy rates if too many power plants were to close rather than invest in remediation.

Environmental regulations generally increase power plant operating costs by requiring plant owners to install capital equipment that controls plant emissions. The electrical load from equipment such as SO_2 scrubbers ("parasitic load") may also reduce the plant's net generation available for sale on the grid. Increased operating costs push the compliant plant farther out on the energy supply (dispatch) curve and can cause it to be dispatched less frequently than it would have without the emissions controls, as shown in Figure 3.21 using coal as an example.

Figure 3.21. PJM Merit-Order Dispatch: Various Control Technologies[133]



This figure shows power plants separated by technology type for PJM, in "merit order", i.e., based on their marginal cost of generation, in the year 2012. The vertical lines represent various levels of load. The diamonds represent marginal costs (sum of fuel and variable operating and maintenance costs) for one subcritical pulverized coal plant with no control technology and that same plant with variations of two select pollution control technologies that reduce acid gas pollution. In principal, all the plants left of a vertical line operate at the level of demand represented by that line. (In reality, transmission constraints and reliability considerations can change that significantly.)

As a plant moves to the right on the curve it will tend to operate less due to the increase in marginal cost. Control technologies key: dry FGD = dry flue gas desulfurization; three types of DSI (hydrated lime, trona, and sodium bicarbonate) = dry sorbent injection. Another control technology not shown that is used to reduce acid gas emissions is wet flue gas desulfurization. Technology key: Renew = other renewables not including hydropower or wind power; Water = hydropower; LOil = light oil-fired power plants; HOil = heavy oil-fired power plants; Nuc = nuclear power.

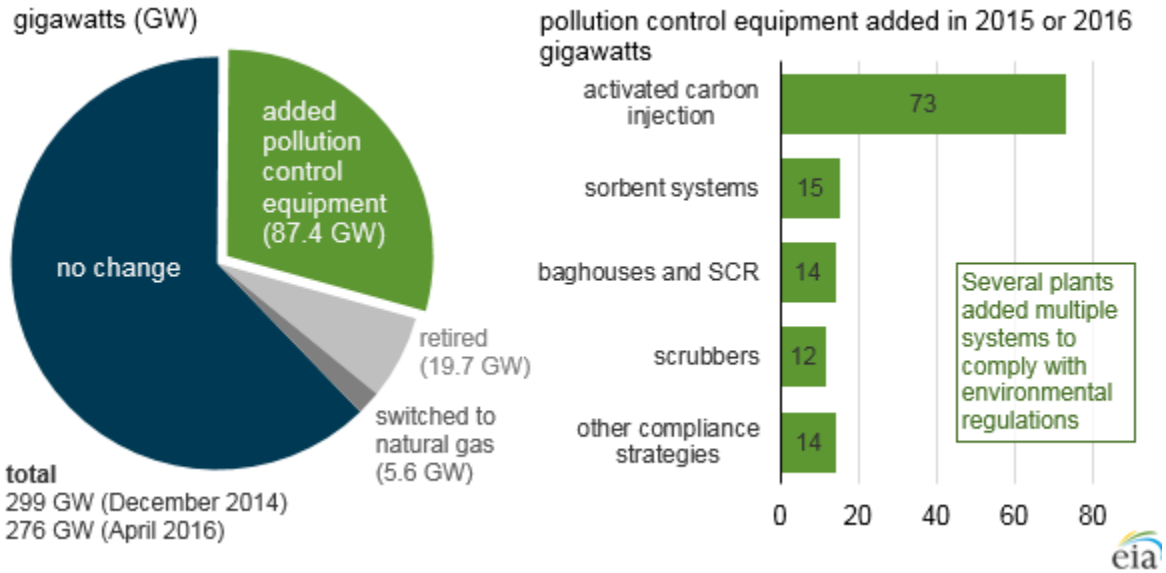
3.6.1 Coal Plants and Environmental Regulation

Existing coal-fired power plants must not only comply with all Federal requirements related to emissions and water use, wastewater treatment, and solid waste management, but also with any additional applicable state regulations.[134] Cost impacts of these regulations varied. The EPA reported that a typical coal-fueled unit with a capacity of 700 MW could incur incremental operating and maintenance costs ranging from $287 million to $351 million to install a scrubber, from $116 million to $137 million to install a selective catalytic reduction unit, and from $97 million to $114 million to install a baghouse (fabric filter). Fitch estimated the lifetime costs and reduced cash flow associated with environmental retrofits at $1,700–$1,900 per kilowatt (kW) for a 100 MW plant burning bituminous coal, as compared with a range of $1,200–$1,300/kW for a 500 MW plant.[135] These costs are on par with those of constructing a new typical (i.e., subcritical) coal plant of similar size during this same time period (averaging $1,361/kW).[136] Reported planned retirements from that time suggest that approximately 27,000 MW or 8.5 percent of 2011 coal-fired capacity was rendered uneconomic under the combination of regulatory compliance costs, little demand growth, and falling natural gas prices.[137]

The MATS rule was potentially the most expensive and immediate of the suite of pending regulations, with a compliance deadline of April 2015 (later extended to April 2016 for some plants). Further, owners of coal facilities were dealing with MATS compliance in combination with the cost of imminent additional regulations of CO_2, along with other GHGs. EIA reported that by the end of 2012, 64 percent of the U.S. coal generating capacity in the electric power sector already had the appropriate environmental control equipment (most reported using flue gas desulfurization) to comply with the MATS rule and operate past 2016; another six percent planned to add control equipment; 10 percent had announced plans to retire; and the other 20.4 percent still had to decide whether, how, and when to upgrade or retire their plants.[138]

The dominant MATS compliance strategy among coal-fired plant owners was to install activated carbon injection (Figure 3.22), which averaged a relatively modest $5.8 million per generator from 2015 to 2016. EIA estimates that "operators invested at least $6.1 billion from 2014 to 2016 to comply with MATS or other environmental regulations."[139] In its rulemaking, EPA estimated an annualized cost of $9.6 billion in 2015, declining to $7.4 billion annually in 2030.[140]

Figure 3.22. Changes in U.S. Coal Capacity, December 2014–April 2016[141]



The retrofit-or-retire decision for owners is also impacted by EPA's New Source Review (NSR) regulations that can affect owners' ability to enhance plant efficiency due to the delay, cost, and uncertainty associated with obtaining an NSR permit. The NSR permitting program requires stationary sources of air pollution—including factories, industrial boilers, and power plants—to get permits before construction starts, whether the unit is being newly built or modified.[142] This is an important concern for owners considering retrofitting an existing power plant with carbon capture equipment to reduce CO_2 emissions, or adding new components to improve operating efficiency. These upgrades could trigger the NSR requirements of the Clean Air Act because they would constitute a "physical change," or lead to a designation of the change as a "major modification," subjecting the unit to NSR permitting requirements.

The uncertainty stemming from NSR creates an unnecessary burden that discourages rather than encourages installation of CO_2 emission control equipment and investments in efficiency because of the additional expenditures and delays associated with the permitting process.[143] [144] Ironically, the uncertainty surrounding NSR requirements has led to a significant lack of investment in plant and efficiency upgrades, which would otherwise lead to more efficient power generation, benefits to grid management, and reduced environmental impacts. EPA has acknowledged these burdens and has made attempts to reform the rules to improve and streamline NSR:

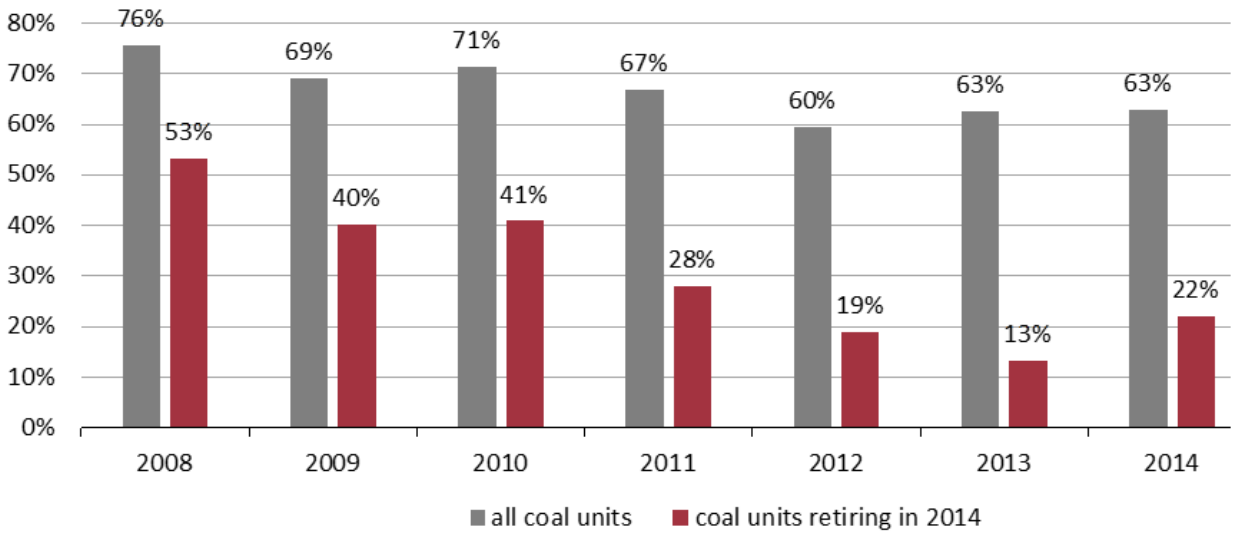
> As applied to existing power plants and refineries, EPA concludes that the NSR program has impeded or resulted in the cancellation of projects which would maintain and improve reliability, efficiency and safety of existing energy capacity. Such discouragement results in lost capacity, as well as lost opportunities to improve energy efficiency and reduce air pollution.[145]

The NSR program distinguished between "routine maintenance and repair" of existing facilities—which would be allowed—and more "substantial modification" of existing facilities, which would put the facilities over the threshold and thus require them to meet new emissions standards.

Environmentalists argued that owners of electric generation and industrial plants were building virtually new facilities from the inside out by exploiting the "routine maintenance and repair" exclusion from NSR. EPA changed its interpretation in the 1990s to a more rigorous standard, culminating in numerous enforcement-related lawsuits beginning in the late 1990s.[146]

By the late 2000s, some older coal units operating without pollution controls were no longer operating as baseload units, having operational capacity factors estimated at 47 percent to 56 percent.[147] As Figure 3.23 shows, rather than acting as baseload units at high capacity factors, these older units (with an average capacity of 109 MW) were operating at falling capacity factors. The units that retired in 2014 had an average capacity factor of 13 percent in 2013.

Figure 3.23. Average Coal Plant Capacity Factors, 2008–2014[148]



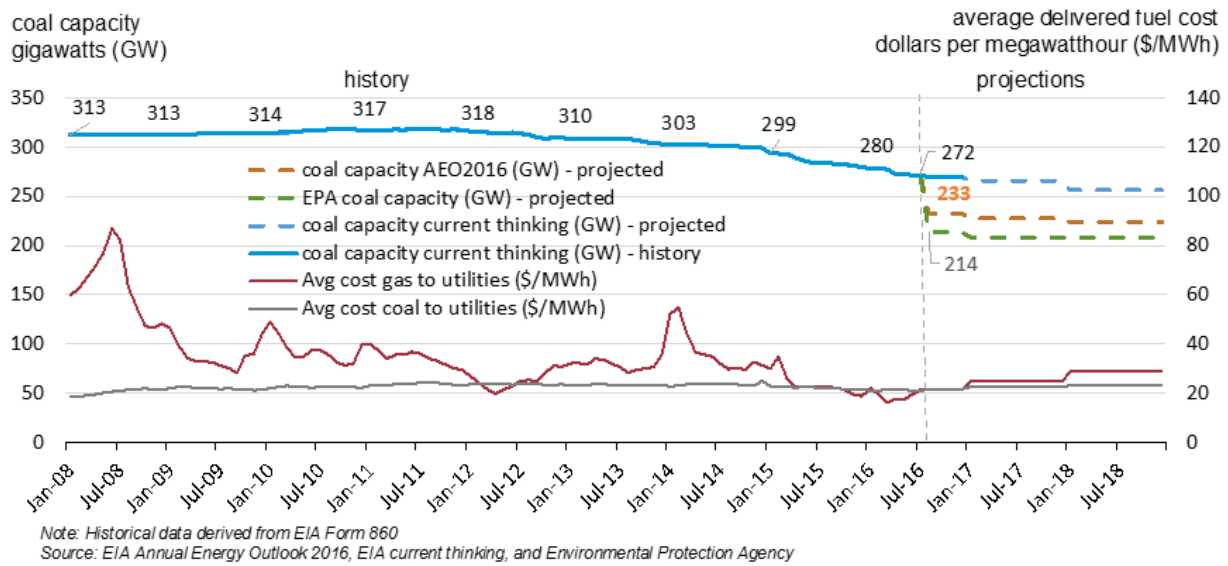
Source: EIA Form 860 and Form 923

Coal plant capacity factors generally fell from 2008 through 2014, with plants that retired in 2014 operating at much lower capacity factors than all coal plants.

Some owners delayed their retirement announcements and retrofit decisions in order to see how the regulation litigation challenges played out, in case a late court ruling made compliance unnecessary, signifying that the cost of complying with those regulations was a factor in their retirement decisions. Others delayed closing uneconomic plants to see if enough other plants retired, in hopes that the resulting shift in market dynamics and prices might render the unretired plants profitable again.[149]

Figure 3.24 shows total U.S. coal capacity from 2008 through mid-2016 and projections through mid-2018. While there was a fall in coal plant capacity in 2015 associated with the MATS compliance deadline, EIA finds that fewer coal facilities retired in 2015 and the first half of 2016 than EIA had projected ahead of the compliance deadline. Specifically, in 2015 and until the April 2016 extended MATS deadline, about 20,000 MW of coal capacity retired and another 9,000 MW of coal capacity converted to natural gas, while EIA projected 50,000 MW of retirements between 2013 and 2020, with the majority retiring in 2015 in response to MATS.[150] However, EIA's projection also included other factors that can drive retirement decisions, such as the Clean Power Plan.

Figure 3.24. Projected and Actual Coal Retirements, 2008–2018[151]



Fewer coal plants retired in 2015–2016 than projected.

3.6.2 Natural Gas Plants and Environmental Regulation

Because natural gas emits far less air pollution than coal-fired power plants,[152] the regulatory burden and cost to natural gas-fired power plants is much lower than for coal plants. ERCOT's December 2014 analysis estimated that the Cross-State Air Pollution Rule (CSAPR)[jj] and the Cooling Water Intake Rule would impose moderate compliance costs on natural gas-fired power plants.[153] Specifically, ERCOT estimated costs of $0.10–$2.75/MWh for CSAPR and $0.10–$0.50/MWh for the Cooling Water Intake Rule.

The large majority of natural gas plants that have retired are NGSTs, which are less efficient than the newer NGCCs.[154] From 2002 to 2016, there was a steady stream of NGST retirements, some of which may be linked to decisions about the cost effectiveness of retrofit upgrades. However, during the period 2014–2016, 23,500 MW of new natural gas capacity was added, nearly double the total natural gas capacity that was retired as part of the transition from NGST units to more efficient NGCC units.[155] NGCC plants have replaced NGST plants for baseload use and natural gas combustion turbines have been built for peak power demand.

3.6.3 Nuclear Plants and Environmental Regulation

The principal environmental regulation affecting nuclear power plants is the Cooling Water Intake Rule, which applies to all types of power plants but is most challenging for nuclear plants. A revised version of the Cooling Water Intake Rule has been in effect since 2003. The rule was promulgated to protect aquatic life. States may decide how to implement the rule, such as by requiring a nuclear (or other) plant to invest in a closed-loop cooling system to replace once-through ocean or waterway cooling. Three of the nuclear plants that have announced closures (Oyster Creek in New Jersey, Diablo Canyon in

[jj] Finalized in 2011 and effective in 2015.

California, and Indian Point in New York) have cited disputes with their respective states over cooling water rule compliance among the reasons for plant retirement. [156] [157]

The Administrative Consent Order between Exelon and New Jersey establishing Oyster Creek's 2019 retirement specifically mentions Section 316(b) of the Clean Water Act as part of the state's justification in requiring the construction of cooling towers if the plant were to operate for the full duration of its license extension.[158]

Nuclear plants are also affected by other regulatory factors and fees that are not imposed on other types of power plants. Recent examples include major safety reviews following the Fukushima Daiichi nuclear plant failures in 2011. A recent study found that the rising regulatory costs of nuclear energy—which approach $60 million per year—exceed the profit margins of many of these plants.[159]

3.6.4 Hydropower Plants and Environmental Regulation

As authorized under the Federal Power Act, FERC issues licenses to non-Federal hydropower projects, which comprise roughly 50 percent of existing U.S. hydropower capacity. The FERC regulatory framework involves numerous participants, such as Federal and state resource agencies; non-governmental organizations; state, local, and tribal entities; and the public. Because of the complexity of the regulatory processes and numerous agencies involved, hydropower licensing timelines often are cited as being among the lengthiest and costliest for energy projects in the United States. A DOE analysis looking at the development timelines of 29 projects that came online from 2005 to 2013 found that the median project took over 15 years from application to operation.[160] For wind and solar, the average permitting time is two to four years.[161]

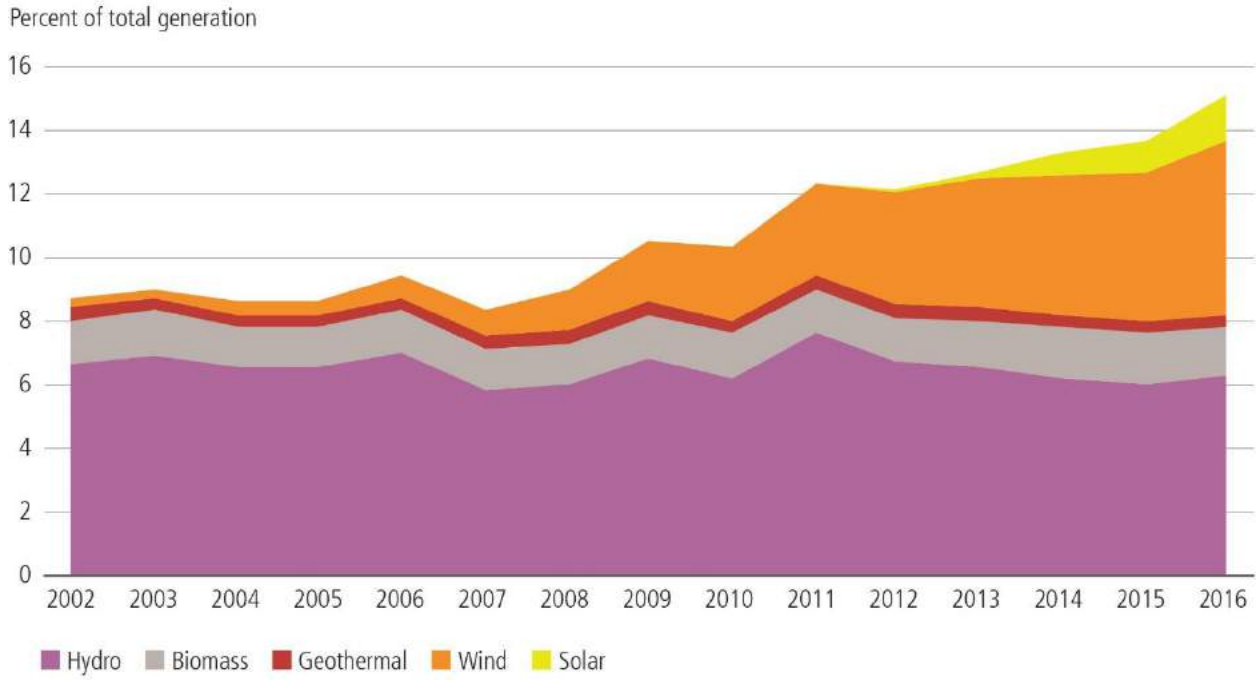
A few hydroelectric power plants have not sought relicensing due to concerns over the cost of meeting mandatory environmental requirements imposed by Federal and state resource agencies. Capital upgrade requirements can include capacity uprates (initiated by the plant owner rather than a regulator), dam safety upgrades, or environmental improvements.[162]

3.7 Growing VRE Deployment

Wind and solar PV—collectively, VRE—have constituted the vast majority of the VRE deployed in recent years. Wind first surpassed 1 percent of total U.S. generation in 2008, while total solar generation reached that threshold in 2015.[kk] Figure 3.25 shows trends in penetration—as a percentage of total generation—for wind, solar, hydroelectric, geothermal, and biomass power plants in the United States since 2001. Total end-use demand served by wind generation tripled from 1.5 percent in 2008 to 4.5 percent in 2013. Total renewable generation has now exceeded 14 percent of the U.S. total, with hydro and wind comprising the largest components.

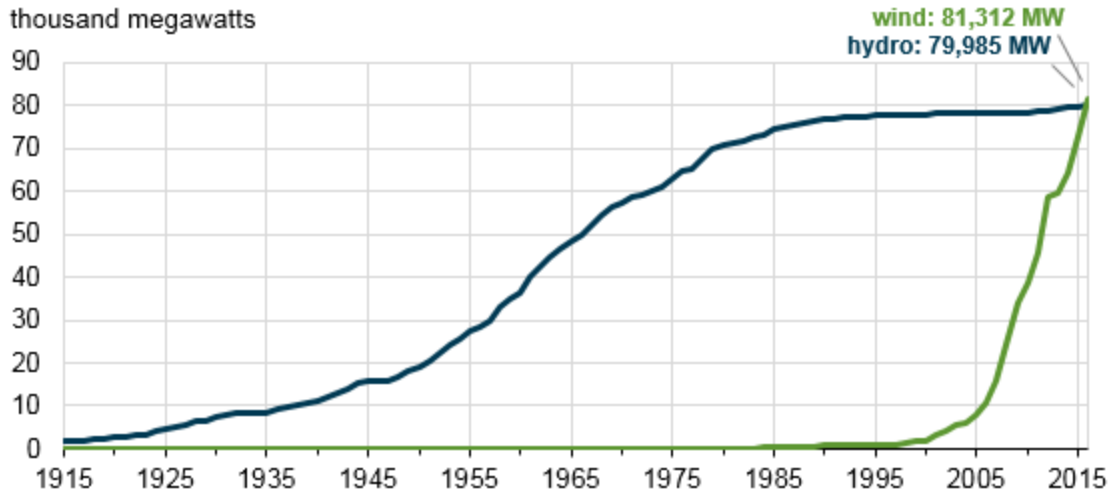
[kk] While annual variation in water availability affects conventional hydroelectric output from year to year, hydro generally has been consistent between 6 percent and 8 percent of total generation since 2001. https://www.eia.gov/totalenergy/data/monthly/pdf/sec7_6.pdf.

Figure 3.25. VRE Generation by Fuel as Percentage of Total U.S. Generation, 2002–2016[163]



At the end of 2016, U.S. installed wind capacity surpassed that of hydro for the first time (see Figure 3.26).[164 165] However, given the hydro fleet's higher average capacity factors and the above-normal precipitation on the West Coast so far this year, hydro generation will likely once again exceed wind generation in 2017, though the gap continues to narrow.

Figure 3.26. Cumulative U.S. Utility-Scale Wind and Hydroelectric Generation Capacity, 1915–December 2016[166]



3.7.1 Technology and Policy Drivers for Deployment

The deployment of wind and solar power has been spurred by a combination of technology cost declines; state RPS; private sector sustainability goals; consumer choice; Federal and state incentives;

transmission expansion—such as the Texas Competitive Renewable Energy Zone project—to reach high-quality resource areas; and Federal and state environmental, air quality, and GHG emissions reductions policies.

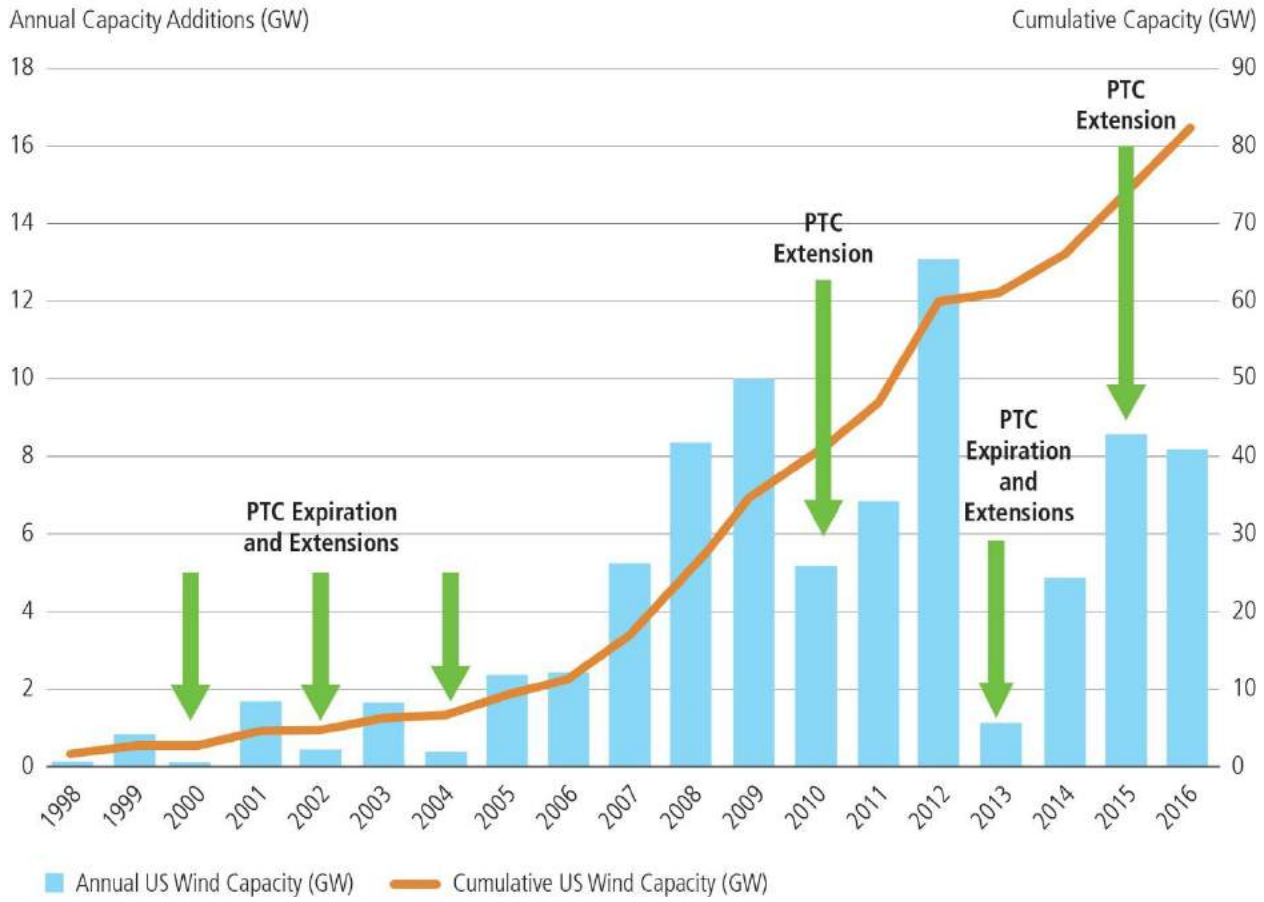
RPS—now in 29 states and the District of Columbia, covering 55 percent of total U.S. retail electricity sales—have also been substantial drivers of VRE growth, as they are associated with 60 percent of renewable generation growth since 2000.[167] Though wind has historically been the largest beneficiary of RPS policies, more RPS-driven solar than wind was added in 2015.[168] RPS also create a market for RECs. RECs represent some of the environmental attributes of renewable generation that can be bought, sold, and applied to meet certain state RPS plans, and they create an additional subsidy to renewable generation.

Technologies typically experience cost reductions as their deployment grows due to technology improvement and increasing economies of scale. Lower investment costs, in turn, spur further deployment—since 2009, solar PV installed system costs have fallen approximately 60 percent on a per kilowatt basis for residential and commercial systems (from \$7.06/W_{DC} to \$2.93/W_{DC} for residential and from \$5.23/W_{DC} to \$2.13/W_{DC} for commercial) and 70 percent for utility-scale systems (from \$4.46/W_{DC} to \$1.42/W_{DC}).[169] However, other factors can interrupt this general trend; for example, increases in warranty costs and the prices of commodities such as steel and fiberglass (among other factors) drove wind turbine installed system costs on a per-megawatt basis to double between 2000 and 2008 (though these costs went on to decline by 40 percent since 2010).[170]

Importantly, these capital cost trends do not account for technology improvements that improve performance and economics. For wind, improvements in turbine technologies and taller towers have resulted in increased capacity factors. For example, in 2015, capacity factors averaged 25.8 percent for wind projects built from 1998–2003 and averaged 41.2 percent for wind projects built in 2014.[171] Similarly, for utility-scale PV, optimized system design—including use of single-axis tracking and increasing inverter loading ratios—partially contributes to capacity factors increasing from 21 percent for 2010 vintage projects to 26.7 percent for 2014 vintage projects in 2015.

In addition to research and development (R&D)—which is aimed at reducing technology costs through innovation—the investment tax credit (ITC) and PTC, as well as state-level RPS, have driven expansion of VRE, particularly wind and solar. Figure 3.27 shows the substantial increase in wind capacity since 1998 during the period when a PTC has been in effect. It also suggests the wind industry's tendency to increase investments in years when the tax credit was due to expire and its extension was uncertain. The current PTC is scheduled to be phased out after 2019.[172] The solar ITC—currently at 30 percent—will be reduced after 2021 to its statutory level of 10 percent for commercial and industrial projects, and will be phased out completely for residential projects.[173]

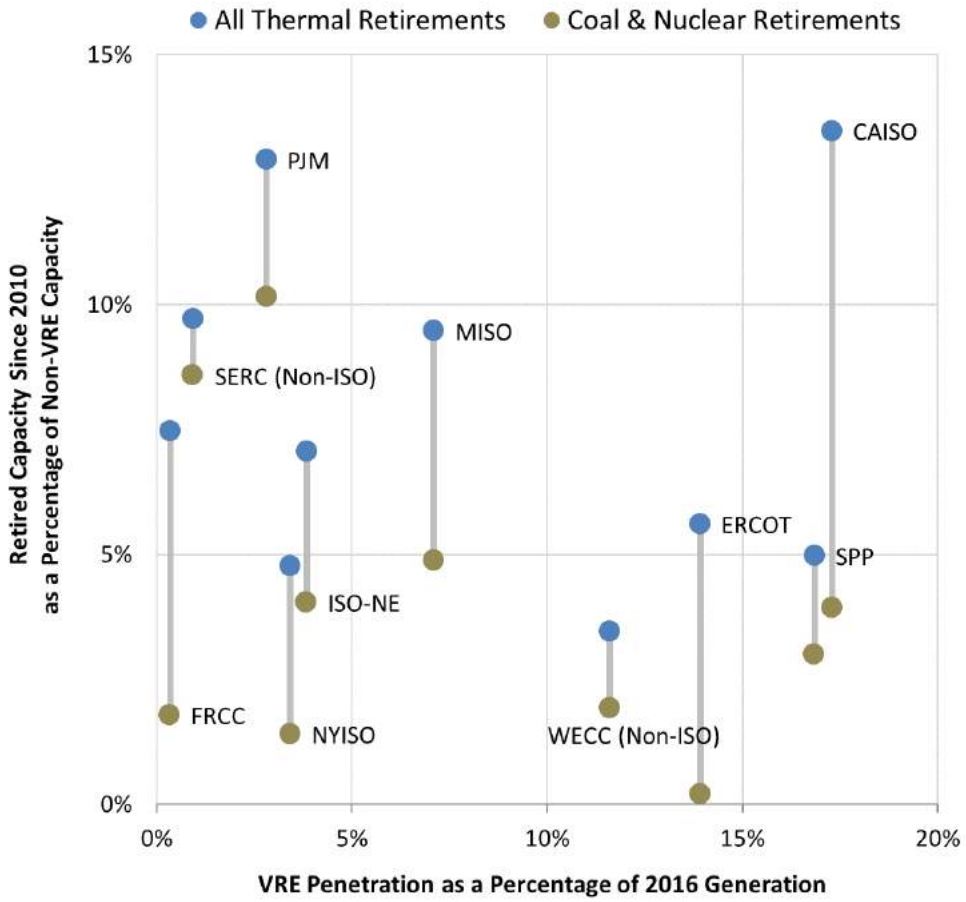
Figure 3.27. Relationship between the PTC and Annual Wind Capacity Additions



The PTC has accelerated wind project deployment significantly—between 2000 and 2013, cumulative wind capacity grew from less than 5,000 MW to more than 60,000 MW—though capacity additions noticeably track the PTC expiration and extension schedule. Similarly, the dramatic decrease in wind capacity additions during PTC expiration years underscore the notion that credits are driving deployment, rather than market decisions. For example, during the PTC expiration "cliff" in 2013, new builds counted for 1 MW of added capacity. After renewal of the PTC, new capacity jumped to 5 MW.[174] This change occurred in the absence of any change in state RPS requirements.

A panel of economists at a May 2017 FERC technical conference cited state-level RPS and Federal tax credits for VRE as examples of market-distorting subsidies and mandates. These policies reduce revenues for traditional baseload power plants by lowering the wholesale electric prices they receive and by displacing a portion of their output. To date, however, the data do not show a widespread relationship between VRE penetration and baseload retirements, as shown in Figure 3.28.[175]

Figure 3.28. VRE Penetration as a Percentage of 2016 Generation versus Retired Capacity since 2010 as a Percentage of Non-VRE Capacity[176]



While concerns exist about the impact of widespread deployment of renewable energy on the retirement of coal and nuclear power plants, the data do not suggest a correlation.

Subsidies

Federal and state governments use subsidies, mandates, and prohibitions to affect how public and private entities behave. Subsidies make the favored behavior or product more appealing relative to other competing products by accelerating its development (as with R&D and direct construction expenditures), lowering its ultimate cost to the consumer (as with tax incentives, low lease payments or grants), or making the product better known and more appealing (customer education, ratings, and marketing). In contrast to subsidies, mandates and prohibitions create absolute requirements for the user for whether and how much of the targeted product to consume.

The Federal Government has always used a variety of subsidies to support a myriad of public and private sector goals. Over the long term, subsidies are spent on different technologies at different times, reflecting differing societal priorities and technology maturities. Early subsidies included Federal construction of hydroelectric dams and multi-purpose water management projects beginning in the 1930s. Energy R&D spending began in the 1950s with the passage of the Atomic Energy Acts of 1946 and 1954, with major Federal investments in the commercialization of nuclear electricity. R&D investments

increased sharply after the oil price shocks and energy crisis in the 1970s, and renewable energy R&D supported VRE.

Accurately accounting for energy subsidies and expenditures is highly dependent on the scope and time period of the analysis. For example, some tax incentives may affect energy industries but are not specific energy-related measures, such as Section 199 of the American Jobs Creation Act of 2004, which allows tax deductions for domestic manufacturing. Natural gas producers, along with many other types of manufacturers, have been able to take advantage of this tax incentive even though it was not an energy-specific measure. This is just one example of the difficulty in examining energy-related subsidies and expenditures both from Federal and non-Federal sources, many of which may not be directly comparable.[ll]

As a snapshot of Federal subsidies and support for electricity generating technologies for a given year, Table 3-5 shows electricity production subsidies and support that includes breakouts by direct expenditures, tax expenditures, R&D, and other Federal programs, compiled by EIA for Fiscal Year 2013. Although this data has not been compiled for every year, the 2013 data can be instructive. For example, VRE technologies received a majority of Federal support that year relative to other technologies, particularly reflecting the technical maturity of VRE relative to conventional technologies.

[ll] For a longer discussion on energy subsidies and various reports examining energy subsidies, see https://www.eia.gov/analysis/requests/subsidy/pdf/subsidy.pdf.

Table 3-5. Fiscal Year 2013 Electricity Production Subsidies and Support[177]

Beneficiary	Direct Expenditures	Tax Expenditures	Research and Development	Federal and RUS Electricity	Total	Share of Total Subsidies and Support
Coal	61	642	167	30	901	6%
Natural Gas and Petroleum Liquids	18	662	10		690	4%
Nuclear	37	1,109	406	109	1660	10%
Renewables	7,408	3,373	722	176	11678	72%
Biomass	62	9	47	-	118	1%
Geothermal	221	22	2	-	245	2%
Hydropower	194	17	10	171	392	2%
Solar	2,448	1,712	234	-	4393	27%
Wind	4,274	1,614	49	-	5936	37%
Other	209	-	380	5	594	4%
Subtotal Renewables Electric	7,408	3,373	722	176	11678	72%
Electricity - Smart Grid and Transmission	8	211	831	134	1184	7%
Total	7,532	5,996	2,136	449	16112	100%

Similarly, it is important to note how these particular results are driven by the unique nature of a given year. For example, the large direct expenditures for wind and solar overwhelmingly arise due to the Treasury 1603 program enabled by the American Recovery and Reinvestment Act of 2009, which allowed one-time cash grants to eligible renewable generators in lieu of tax credits. This was only available to generators who began construction in 2009–2011, and as such is no longer a direct expenditure.

There is no complete multi-year assessment available that describes and analyzes the Federal subsidies and support provided to different generation technologies over time. Continued examination of Federal subsidies and support, and provision of this information to the public, can better inform the decisions made by Federal, state, and local entities.

Workforce Impacts of Growing VRE Deployment

As the electricity system changes, so do the types of jobs, skills needed, and education or training required. The evolving demands of the grid are creating new opportunities in information and communication technologies and in the deployment of new generation, including natural gas and VRE. Job growth has been strong in the VRE sector, and the solar and wind workforce increased by 25 and 32 percent, respectively, in 2016.[178] DOE's *2017 U.S. Energy and Employment Report* found that the solar and wind industries provide 373,000 and 101,000 jobs, respectively, across the Nation.[179] Veterans

comprise a higher percentage of employees in the electricity industry compared to other industries, and in 2015, the solar industry provided nearly 17,000 jobs for veterans in manufacturing, installation, and project management.[180]

3.8 Flattening Electricity Demand

Between 1970 and 2005, total U.S. electricity generation to meet customer demand grew at a compound annual growth rate (CAGR) of 2.7 percent.[181] But since 2005, generation growth has stalled with a CAGR of only 0.05 percent from 2005 to 2015, even as the Nation's GDP grew by 1.3 percent per year over the same period.[182]

Electricity demand historically had risen with economic growth (real GDP), but the two began decoupling around 2000, as shown in Figure 3.29. EIA attributes this decline in the demand growth rate to a variety of factors, including the cumulative impact of energy efficiency programs, standards, and codes; technology improvements in appliances, lighting, and other end-use equipment; and broader structural changes, such as a shift toward less electricity-intensive industries and slower population growth.[183]

Figure 3.29. Gross Domestic Product and Net Electricity Production, Historical (1950–2016) and Projected (2017–2027)[184 185 186 187]

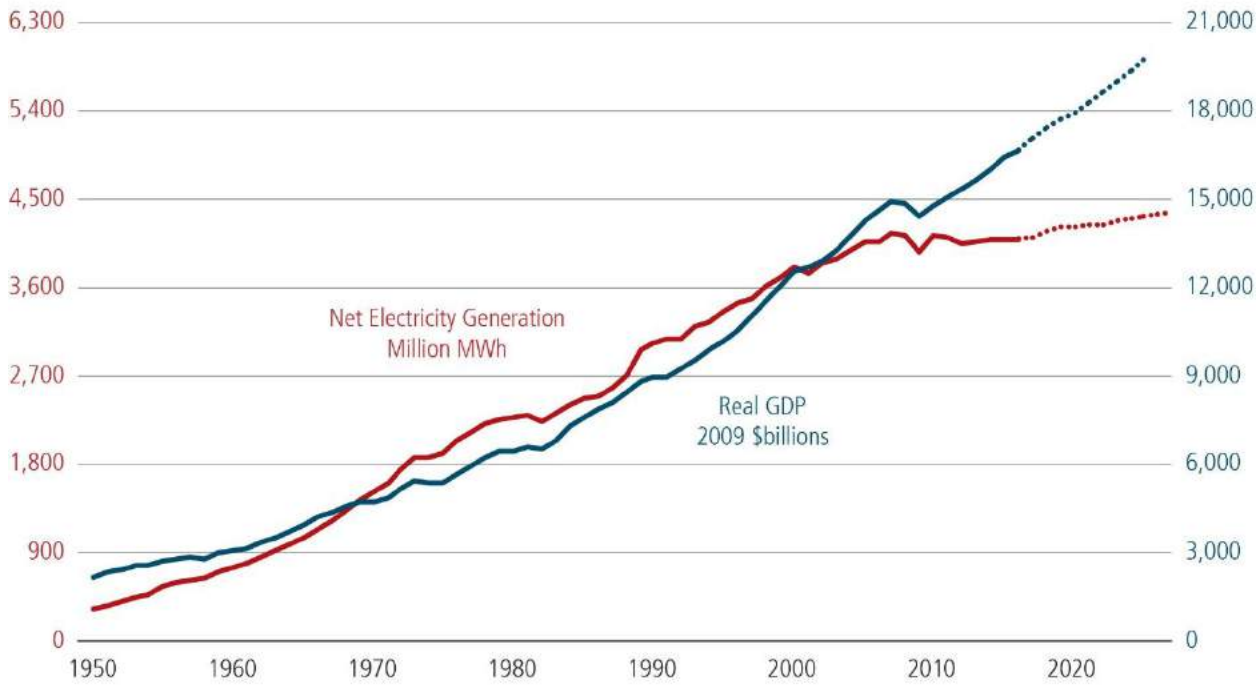
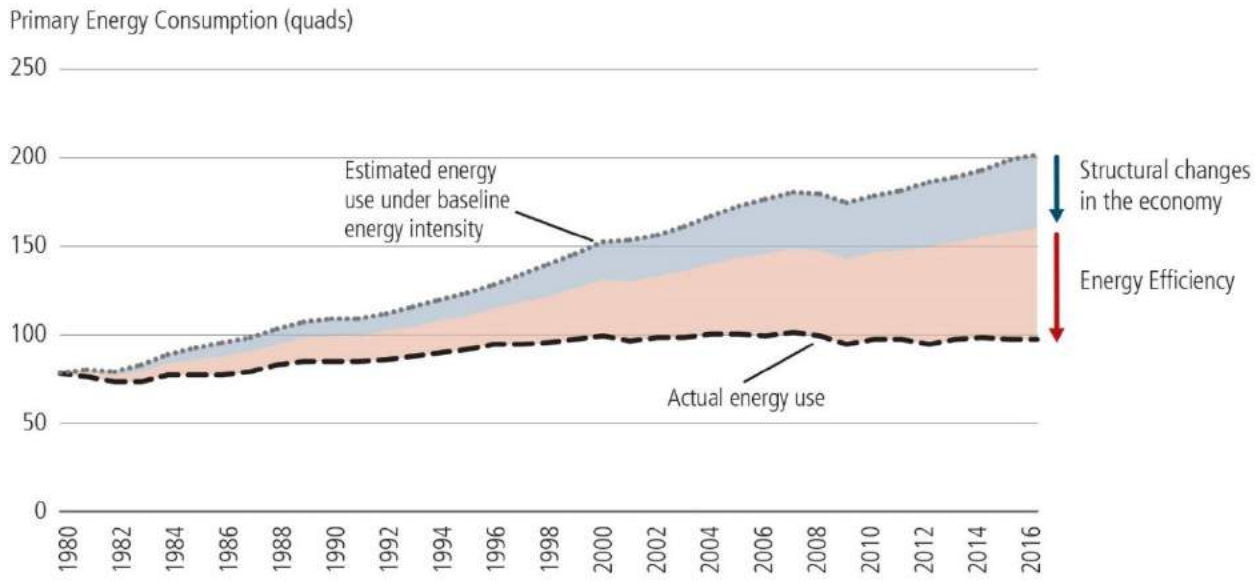


Figure 3.30 shows one analysis of how efficiency improvements, coupled with structural changes in the economy, have led to flattening energy use in recent years. Overall, there has been significant progress across the U.S. economy in improving the value of goods and services produced per unit input of energy. For example, electricity productivity in the industrial sector—measured in dollars of economic output per kilowatt-hour of electricity input—nearly doubled between 1990 and 2014. The noticeable dip in both GDP and net electricity generation in 2008–2009 reflects the U.S. recession, which lowered electricity usage enough to affect power plant economics and prompt some plant closures.[188]

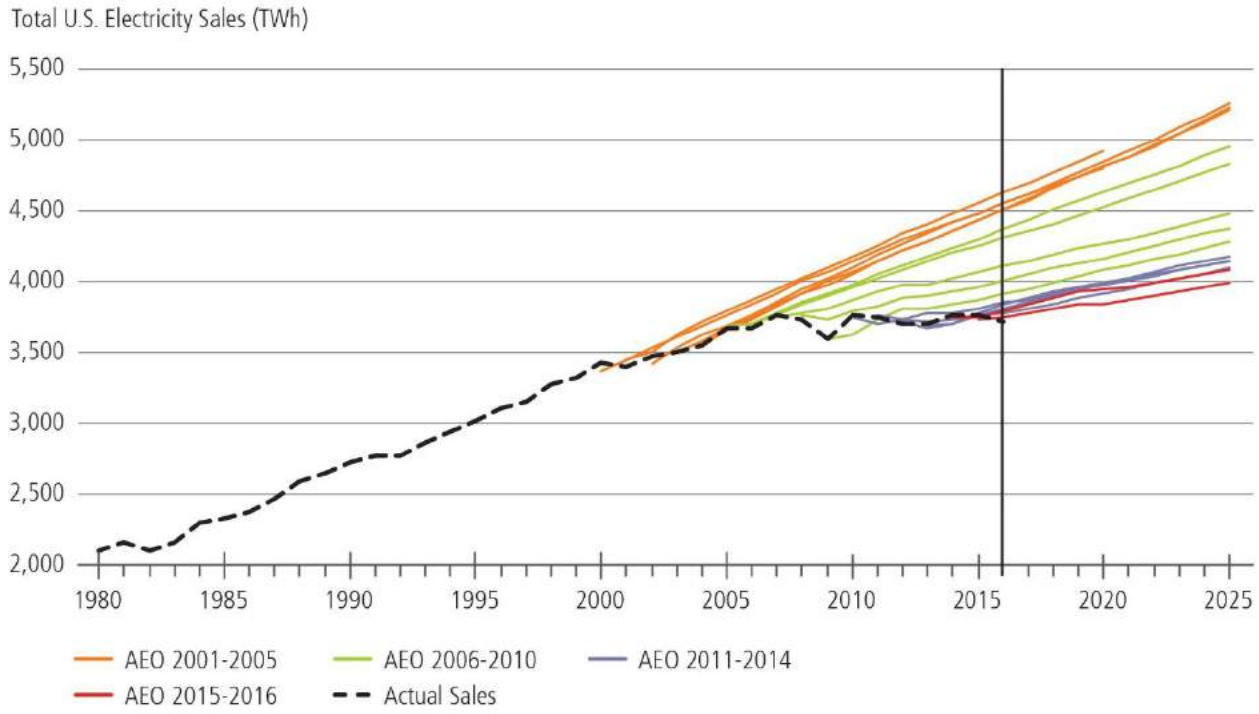
Figure 3.30. Estimated U.S. Energy Savings from Structural Changes in the Economy and Energy Efficiency, 1980–2016[189 190]



The U.S. economy has made significant progress in improving the value of goods and services produced per unit input of energy, through both energy efficiency and structural changes to the U.S. economy.

Figure 3.31 shows more broadly the impact of these changes on the EIA's Annual Energy Outlook (AEO) Reference case electricity sales forecast for various years. Each AEO forecast is made assuming that laws and regulations in effect at the time of the projection will continue unchanged through the projection period, unless scheduled end dates for those laws and regulations are within that period. The objective is to provide a “business-as-usual case;” no assumptions about new policies are included. Over the past several decades, new Federal and state policies, market forces, and broader economic factors have contributed to lowering levels of electricity consumption compared to what was expected to occur in absence of any new policy, as shown by the comparison of historical Reference case projections to actual U.S. electricity sales (shown as dotted lines in Figure 3.31).

Figure 3.31. EIA Annual Electricity Sales 2000–2016 (terawatt-hours) and AEO Reference Case Electricity Sales Projections 2017–2030[191]



A changing policy and market environment since 2000 has made it challenging to accurately forecast electricity demand. TWh is terawatt-hours.

As stated in QER 1.2:

> Currently, about 90 percent of residential, 60 percent of commercial, and 30 percent of industrial energy consumption are used in appliances and equipment that are subject to Federal minimum efficiency standards implemented, and periodically updated, by the Department of Energy. Between 2009 and 2030, these cost-effective standards are projected to save consumers more than $545 billion in utility costs, reduce energy consumption by 40.8 quads, and reduce carbon dioxide emissions by over 2.26 billion metric tons.[192]

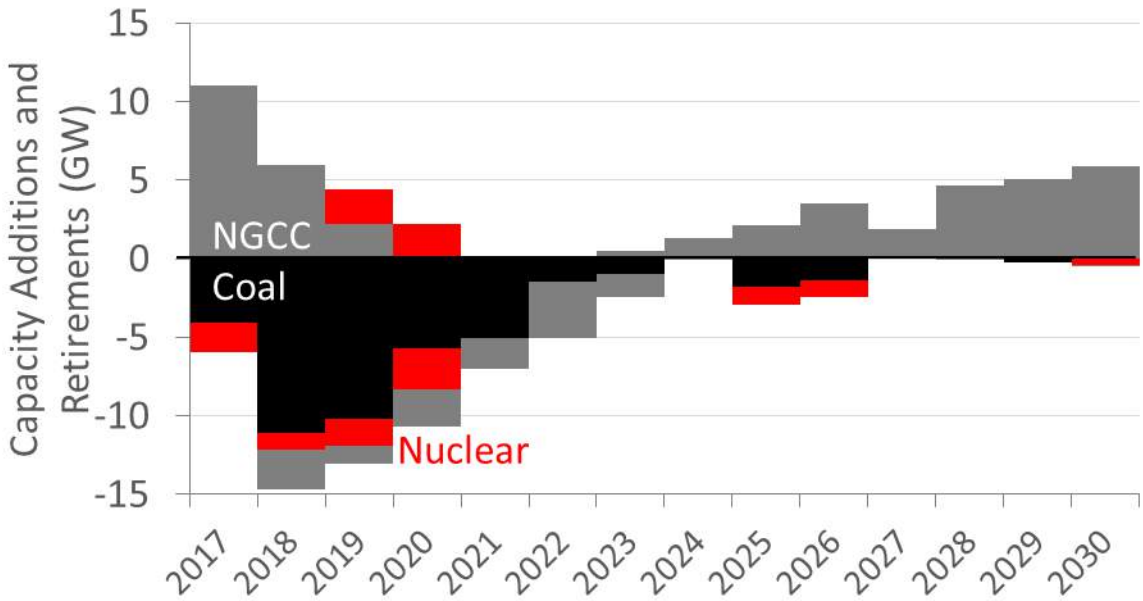
There are two significant impacts from the growth in energy efficiency. First, suppliers can no longer expect robust demand growth. Second, because customers are buying less electricity, the market price of electricity clears lower on the electricity supply curve (all else equal). Thus, higher-cost power plants that might have been dispatched and earned revenues in a higher-demand market are dispatched less frequently and earn less revenue due to increased energy efficiency.

[nn] The report, *Economic and Market Challenges Facing the U.S. Nuclear Commercial Fleet*, produced by Idaho National Laboratory and the Center for Advanced Energy Studies (September 2016), attributes low electricity market prices to "low natural gas prices, low demand growth, increased penetration of renewable generation, and negative electricity market prices."

3.9 Power Plant Retirements Looking Forward

While recognizing the difficulty in making any long-range forecast, it is useful to examine modeled scenarios to understand how the factors affecting retirements are expected to evolve. Figure 3.32 shows the announced and modeled coal, NGCC, and nuclear retirements and additions from 2017 through 2030 in EIA's AEO 2017. This shows that coal retirements are projected to continue in the near term—with 37,800 MW projected to retire between 2017 and 2022—and taper off in the longer term, with another 4,400 MW of retirements between 2023 and 2030. Announced nuclear retirements in the near term account for most projected retirements, with an additional 3,000 MW of modeled unplanned retirements in the period 2019–2020 due to market conditions and uncertainty. A modest number of NGCC plants are also expected to retire in the near term in this modeled scenario.

Figure 3.32. Baseload Capacity Additions and Retirements from EIA AEO 2017 (No Clean Power Plan Scenario)[193]



Three factors impacting the economic conditions of baseload generators that are modeled in the AEO—natural gas price, electricity sales, and VRE generation—are shown in Figure 3.33 below. In general, there is a mixed outlook for these factors as they affect baseload generators:

1. Natural gas prices for the electric power sector are modeled to rise modestly, increasing 30 percent over 2017 levels by 2022 and rising more slowly thereafter. While this may provide some upward pressure on electricity prices, natural gas prices are notoriously challenging to predict.
2. Electricity continues to grow at a slow rate—modeled at 0.8 percent CAGR through 2030.
3. Over the same period, VRE generation is modeled to approximately double to 600 terawatt-hours by 2030. The majority of this growth occurs by 2024 and slows thereafter, reflecting the expiration and stepdown of the PTC and ITC in 2020 and 2022, respectively. Based on these trends, unless natural gas prices or electricity demand rise significantly faster than projected, the economic conditions of baseload generators are not projected to change significantly in the near term.

Figure 3.33. Modeled Projections for Natural Gas Price, Electricity Sales, and VRE Generation from EIA AEO 2017 (No Clean Power Plan Scenario)[194]

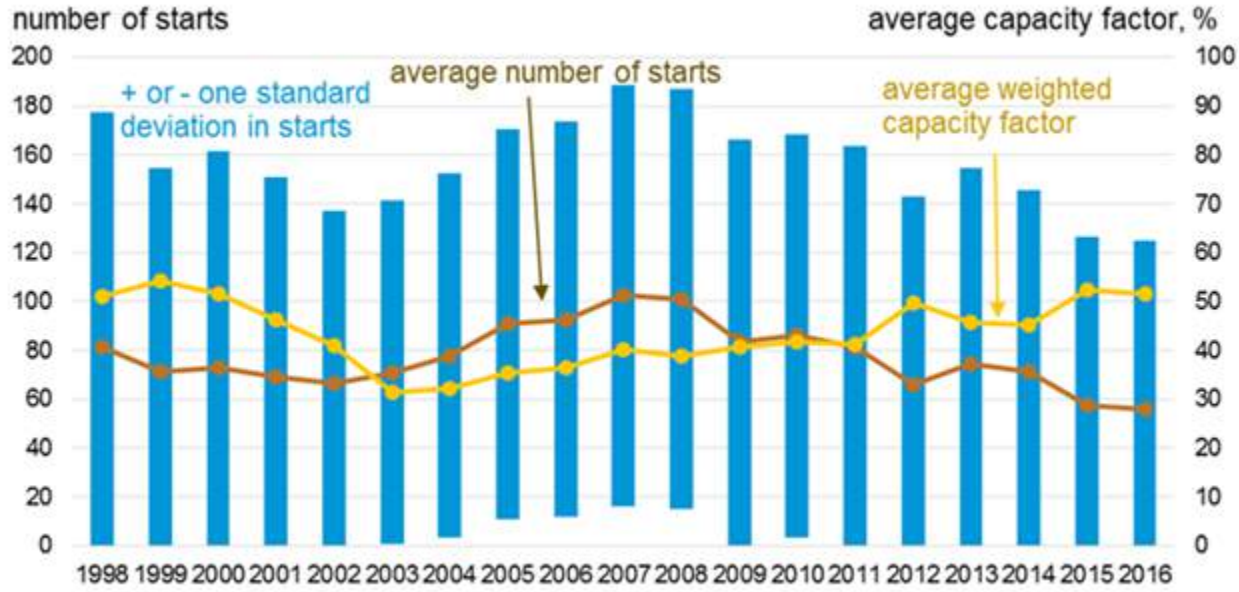
VRE generation includes wind, utility-scale PV, and distributed PV. MCf is million cubic feet

While the financial strains on existing coal, nuclear, and even older natural gas plants have been real and significant, the role of conventional resources continues to evolve. PJM notes the changing nature of baseload:

> "Baseload" can generally be thought of as those units which operate the great majority of hours of the year to meet load requirements. Given the reduction in gas prices, we have seen a noticeable inversion in the types of units which clear in the market in the off-peak hours and thus fit the traditional notion of "baseload." Specifically, due to low energy prices and the overall efficiency of the units, combined cycle natural gas units are dispatched as baseload with coal units more often being cycled and thus dispatched in what has traditionally been deemed "mid-merit" units.[195]

EIA staff analyzed NGCC unit dispatch trends over time, from 1998 to 2016.[196] NGCC plant operation closely follows natural gas prices—when prices were high in the mid-2000s, the number of NGCC starts (when the plant goes from zero output into production) increased as the capacity factor decreased, confirming that these plants were used more in load-following mode rather than baseload-operation mode. Capacity factor has been rising steadily and starts have fallen since about 2010, indicating that NGCC units are being used in more hours at higher capacity factors—i.e., in baseload-type operation (see Figure 3.34).

Figure 3.34. NGCC Capacity Factors and Number of Starts, 1998–2016



Decreased starts and increased capacity factors indicate that NGCC plants are increasingly used for baseload-type operation.

Market conditions will continue to be dynamic, such as with the scheduled phasing out of the wind PTC and solar ITC. Trends in natural gas prices and efficiency gains would also need to be thoroughly examined and accurately forecast in order to get a clearer picture of expected retirements over the coming years. In the event present market, policy, and technology conditions continue, the retirement of coal and nuclear facilities is likely to continue, as well as new builds of natural gas and VRE capacity.

Going forward, coal and natural gas generators will continue to monitor several EPA rules:

- The Steam Electric Effluent Limitation Guidelines have been postponed until EPA completes review of the rule finalized in 2015.[197] EPA recently completed an extended public comment period of the rule and comments are currently being reviewed.[198] Based on the 2015 finalized rule, EPA estimated industry-wide costs at approximately $480 million per year,[199] although industry groups such as the Utility Water Act Group dispute this estimate.[oo] [200]
- The Cooling Water Intake Rule for existing sources is currently being phased in. Regions have been given authority to consider requirements for power plants on a case-by-case basis. EPA estimated an annualized post-tax final rule cost of $147.6 million for electric generators.[201] However, due to the flexibility allotted to the regional permit directors, the compliance timeline and costs are unclear.
- While MATS and CSAPR have affected plant decisions to retrofit or retire in the recent past, most of the capital investment for MATS and CSAPR compliance has already occurred (see Table 3-4). In the future, generators will continue to have smaller operating and maintenance costs associated with MATS. For example, based on generator survey responses, ERCOT estimates an average operating and maintenance cost for MATS of $0.75/MWh,[202] which is approximately

[oo] According to a petition submitted by the Utility Water Act Group, selected *individual* compliance cost estimates from its members included: $308 million (Dynegy), $200 million (NRG Energy), and $400–$500 million (American Electric Power).

3 percent of the average monthly day-ahead wholesale electricity price (approximately $23.5/MWh) for the ERCOT North Hub from 2015 to 2016.[203]

- The Coal Combustion Residuals Rule, prompted by a 2008 coal ash spill, is currently being implemented.[204] EPA estimated the annualized cost of the rule to be $509–$735 million for coal-fired electric utilities.[205]
- The Regional Haze Rule, which currently requires states to submit state plans for compliance by 2021, is expected to mainly affect Western states (the rule aims to improve visibility in national parks, which are located primarily in Western states). It also includes a provision allowing power plants that are already complying with CSAPR (eastern half of the United States[206]) to substitute their compliance status for compliance with the Regional Haze Rule.[207] [208]
- In 2015, EPA finalized New Source Performance Standards, entitled Carbon Pollution Standards, which set CO_2 emission limits for new generators.[pp] These standards are currently under legal challenge.
- The Clean Power Plan rule to reduce CO_2 emissions from existing power plants was promulgated by EPA in 2015 for effect in 2022 for existing plants, but those rules are under review by EPA—which may initiate actions to rescind them—and by the courts.

Several large coal plants built after 1970 with capacities greater than 1,000 MW have announced plans to retire in the next few years. These plants have already made the capital investments needed to comply with MATS, indicating that MATS itself is not the single forcing factor in these retirement decisions. Although these plants were designed to operate around the clock, low wholesale electric prices tied to natural gas were a significant driver that caused them to operate at lower capacity factors. As Rhodium Group analyst John Larsen states:

> The wider market dynamics are more concerning for coal…. For a power plant to make money today, it must be able to ramp up and down to coincide with the variable levels of renewable generation coming online. That makes combined cycle natural gas plants profitable, even at lower prices. [But] coal plants have relatively high and fixed operating costs and are relatively inflexible. They make their money by running full-out.[209]

While there have been significantly fewer retirements of hydropower generation than coal or nuclear, this does not mean that hydropower operators are immune to the same market and regulatory forces that have affected other baseload plants. Depressed prices and costly regulatory barriers decrease the margins on all hydroelectric facilities and, in some cases, cause economic stress.[210] A certain amount of new development continues, primarily through powering existing non-powered dams and installing hydropower in conduits and other constructed waterways. Two hundred and forty-two new hydropower projects, with a total capacity of 3,250 MW, were in the U.S. development pipeline at the end of 2016, including 93 MW under construction. At least nine projects (225 MW) reached commercial operation in 2016.[211]

[pp] Under current market conditions, these standards were not expected to affect new build decisions because economic conditions were already unfavorable for building new coal units. For example, EIA's 2015 AEO, which does not include the Clean Air Act 111(b) carbon standards for new coal plants, builds only a very small amount (roughly 400 MW) of new coal capacity by 2040 beyond what is already planned. https://www.eia.gov/outlooks/aeo/pdf/0383(2015).pdf.

4 Reliability and Resilience

The April 14 memo expressed concerns over whether the erosion of baseload power is compromising a reliable and resilient grid. It also asked whether wholesale energy and capacity markets are adequately compensating attributes that strengthen grid resilience and, if not, the extent to which that could affect grid reliability and resilience in the future. Indeed, a recent National Academies study indicates that there is a growing emphasis within the industry on grid resilience.[212] In this chapter, we address those issues, starting with the question of whether grid reliability has been lessened by the retirement of baseload and other coal, nuclear, and natural gas power plants over the past 15 years.

The Department staff offer three general findings:

> 1) A diverse portfolio of generation resources and well-planned transmission investments are critical to meeting regional reliability objectives. A resource portfolio approach is necessary to ensure ERS, fuel assurance, and flexibility capabilities are available. Conventional generation sources, in particular hydropower, combustion turbines, and steam turbines, are currently the chief providers of these attributes.
>
> 2) One of the greatest challenges to integrating VRE lies in managing its effects (variability, uncertainty, location specificity, non-synchronous generation, and low capacity factor) on grid operations and planning. Lack of long-term forecasting, for example, increases risks when scheduling planned generation outages and managing severe weather events.
>
> 3) There are tradeoffs between multiple desirable attributes for the electric grid. A more reliable and resilient system may be more costly than the least-cost system. Consumer life, safety and health are dependent on a reliable and resilient electric grid, making the grid a national security asset. Infrastructure hardening[213] and grid recovery and restoration strategies require advanced planning and investment.

Reliability

NERC defines BPS reliability as a function of adequacy and operating reliability. In this context, NERC defines adequacy as, "the ability of the electric system to supply the aggregate electric power and energy requirements of the electricity customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system components." Operating reliability is defined as, "the ability of the electric system to withstand sudden disturbances to system stability or unanticipated loss of system components."[qq 214]

Reliability operates in different time scales. Long-term reliability is closer to resource adequacy: it is the business of ensuring that there will be enough resources available to serve customers' load several years

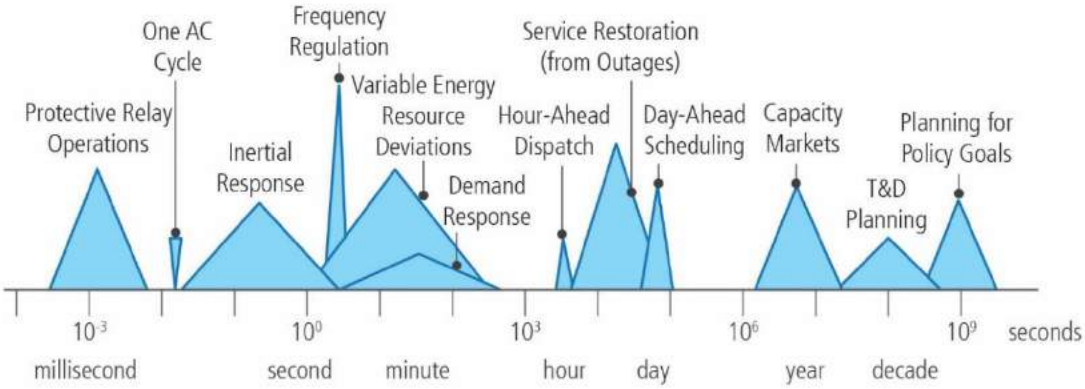
---

[qq] *Both* components of reliability are needed. Adequacy, often called "resource adequacy," is much easier to model and thus forecast for the future, particularly a decade or two out. Most longer-term studies, such as by DOE and its national laboratories, largely look at this one aspect of reliability (with some consideration of operational reliability aspects as well). Operational reliability, in contrast, is very difficult (both in data needed and computational complexity) to completely model and thus forecast in definitive terms many years out.

out plus a reserve margin (typically 15 percent). Short-term reliability ensures that there will be enough capacity to meet demand over the next few hours. Maintaining short-term reliability has grown more complex in light of higher levels of VRE, evolving customer electricity usage patterns, and the wider use of 15-minute load metering and customer time-of-use rates. However, grid operators have kept up with these factors by developing new information technology and analysis capabilities, such as more sophisticated wind and solar forecasting tools.

Figure 4.1. illustrates the timescale for different grid events. Events on very short timescales, such as frequency regulation, match second-by-second generation and demand. Medium-term activities and factors include day-ahead and day-of energy markets, security-constrained economic dispatch,[rr] contingency analysis, asset availability, relay and other equipment operations, and operator action. Longer-term activities and factors include system planning, capacity markets, interconnection rules, reliability standards, and energy market designs. Grid operators must thoroughly consider all these timescales and their associated events in ensuring short-term through long-term reliability.

Figure 4.1. System Operation Time Scales[215]



Planning to maintain system reliability depends on managing (potentially) multiple events in varying time scales.

NERC's CEO Gerry Cauley spoke to the Energy Secretary's concerns by describing the current reliability issues.

> As a common thread in each of our Reliability Assessments, the most pressing reliability issues in North America are:
>
> - As conventional resources prematurely retire, sufficient amounts of essential reliability services, such as frequency and voltage support, ramping capability, etc., must be replaced based on the configuration and needs of the system.
> - Resource flexibility is needed to supplement and offset the variable characteristics of solar and wind generation.
> - Higher reliance on natural gas exposes electric generation to fuel supply and delivery vulnerabilities, particularly during extreme weather conditions. Maintaining fuel diversity and security provides best assurance for resilience. Premature retirements

[rr] "Security-constrained economic dispatch [of power plants] is an area-wide optimization process designed to meet electricity demand at the lowest cost, given the operational and reliability limitations of the area's generation fleet and transmission system." https://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/final_ED_03_01_07_rev2.pdf.

of fuel secure baseload generating stations reduces resilience to fuel supply disruptions.

- Because the system was designed with large, central-station generation as the primary source of electricity, significant amounts of new transmission may be needed to support renewable resources located far from load centers.[216]

To make risk-informed decisions about how to maintain and protect BPS reliability, NERC has often stressed the need to study evolving market, technology, policy, and regulatory factors, as well as to understand how they are affecting "fuel supply, generation and transmission infrastructure planning, operations and investment decisions."[217]

Resilience

NERC uses the infrastructure resilience definition that the National Infrastructure Advisory Council developed in 2010: "Infrastructure resilience is the ability to reduce the magnitude and/or duration of disruptive events. The effectiveness of a resilient infrastructure or enterprise depends upon its ability to anticipate, absorb, adapt to, and/or rapidly recover from a potentially disruptive event."[218] Examples of events that test a system's resilience include severe natural events (wildfires, hurricanes, floods, droughts, and earthquakes) and coordinated, extensive physical and cyber-attacks and geomagnetic disturbances.

Resilience is typically achieved through hardening or recovery. Hardening refers to physically changing infrastructure to make it less susceptible to damage. Hardening improves the durability and stability of energy infrastructure, making it better able to withstand the impacts of hurricanes, weather events or attacks. Recovery, by contrast, refers to the ability of an energy facility to recover quickly from damage to any of its components or to any of the external systems on which it depends – typically through storage and redundancy. Recovery measures do not prevent damage; rather, they enable energy systems to continue operating despite damage, and/or they promote a rapid return to normal operations when damages/outages occur. Advanced planning for contingencies, interagency coordination, and training exercises enable an effective restoration process.

BPS reliability is adequate[219] today despite the retirement of 11 percent of the generating capacity available in 2002, as significant additions from natural gas, wind, and solar have come online since then. Overall, at the end of 2016, the system had more dispatchable capacity capable of operating at high utilization rates than it did in 2002.[220] The composition of the BPS and its requirements, however, are changing, so simple extrapolation of previous reliability trends is not prudent. In this chapter, we review current system reliability and resilience, look at how power plant operations are changing with the evolving generation mix, and evaluate potential reliability and resilience issues.

4.1 Assessing Challenges to Reliability

NERC is the primary entity responsible for ensuring BPS reliability,[ss] and collaborates with FERC to ensure compliance. Over the last several years, NERC has consistently highlighted how the power

[ss] NERC is the designated "electric reliability organization" under the Energy Policy Act of 2005, monitoring reliability for all lower 48 states and, under special agreement, portions of the Canadian and Mexican grids.

sector's rapid transformation may require new approaches to reliability measurement and planning in order to ensure continued reliability.[tt] [221] [222] [223] [224] [225]

NERC believes BPS reliability is adequate as measured by various metrics,[226] but is undertaking various initiatives to address potential reliability challenges posed by the changing generation mix. For example, NERC created an Essential Reliability Services Working Group to draw attention to the need to maintain these services[uu] as the resource mix evolves.[227] NERC also created the Integration of Variable Generation Task Force and the Distributed Energy Resources Task Force to address the reliability implications of increasing levels of distributed generation.[228]

NERC's position on the reliability implications of the evolving resource mix is best summarized in its recent communication with DOE (see text box below).

NERC: How the Changing Resource Mix Affects Reliability[229]

The North American BPS is designed to be a highly reliable, robust, and resilient system. The system is interconnected, and the integrated networks work together to maintain reliability through both wide-area interregional planning and coordinated system operations. The adequacy of the system is maintained by having the right combination and amount of resources and transmission to deal with unexpected facility outages or extreme weather events that increase system demand. Operating reliability is maintained in real time through highly coordinated operator actions across many operating companies. The system is also planned as many as 15 years in advance by performing highly detailed, complex, and data-intensive power system simulations.

The resource mix of the BPS is changing in fundamental ways. Variable energy resources, especially wind and solar, are rapidly expanding and capturing the majority share of new capacity additions. Conventional generation (such as coal and nuclear) are retiring and have become economically marginalized. The balancing resource tends to be natural gas, as environmental rules and commodity economics tend to make oil-fired generation uneconomic. Developing hydroelectric resources, a major energy source in some parts of the country (such as the West), is extremely challenging. The confluence of the changing resource mix can fundamentally impact reliability in two major ways:

1. A balancing authority responsible for managing the balance of demand and resources through unit commitment. Forecasting may become capacity deficient and unable to serve firm load. Resources may not be available when needed, particularly those that have not secured onsite fuel. In that instance, manual load shedding may be required to maintain reliability.
2. Large, unanticipated voltage or frequency deviations during a disturbance, which can lead to uncontrolled, cascading instability. With no mass, moving parts, or inertia, increasing amounts of inverter-based resources (such as solar photovoltaic) present new risks to reliability, such as managing faster fault-clearing times, reduced oscillation dampening, and unexpected inverter action.

The rapid changes occurring in the generation resource mix and technologies are altering the operational characteristics of the grid and will challenge system planners and operators to maintain reliability. More specifically:

- Impact of Premature Retirements: Conventional units, such as coal plants, provide frequency support services as a function of their large spinning generators and governor-control settings, along with reactive support for voltage control. Power system operators use these services to plan

[tt] NERC's concerns about the reliability implications of the fast-evolving grid transformation underway were so strong that it chose to *rename* a set of key components of operational reliability from a term understood only by engineers and others directly involved in reliability, the term "ancillary services," to the plainer English and self-defining, "essential reliability services."

[uu] ERS include frequency response, voltage support, and ramping.

and operate reliably under a variety of system conditions, generally without the concern of having too few of these services available. Coal-fired and nuclear generation have the added benefits of high availability rates, low forced outages, and secured onsite fuel. Many months of onsite fuel allow these units to operate in a manner independent of supply chain disruptions.

- Replacement Resource Capability and Characteristics: As the generation resource mix evolves, the reliability of the electric grid depends on the operating characteristics of the replacement resources. Natural gas-fired units, variable generation, storage, and other resources can provide similar reliability services. However, as a practical matter, costs, market rules, or regulatory requirements (or lack thereof) can affect whether these resources are equipped and available to provide reliability services. To ensure reliability, new generator and load resources must maintain the balance between load and generation, especially during ramping periods. In addition, in some jurisdictions, substantial amounts of generation are now being added "behind the meter" (e.g., roof top solar), and these resources are invisible to system operators.

Planning Reserve Margins

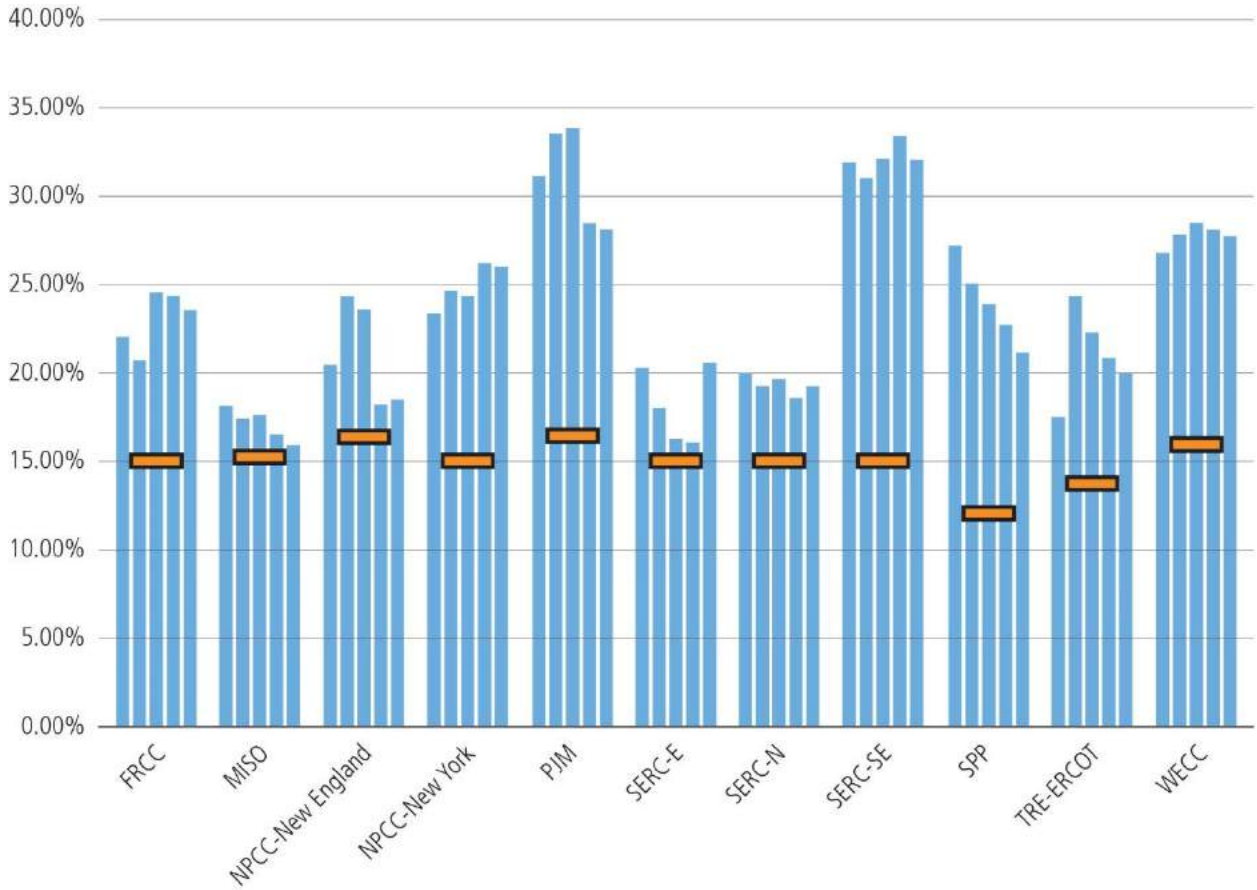
In terms of the resource adequacy part of reliability, NERC reports that all regions project more than sufficient planning reserve margins. NERC and its regional reliability coordinators conduct ongoing analyses to assess resource adequacy as system conditions change over time. Figure 4.2. shows that planning reserve margins[vv] exceed their respective regional targets despite the loss of traditional baseload capacity since 2002.[230] The orange bars in the figure indicate regional or NERC-determined target reserve margins for resource adequacy, which in most cases are administratively set at 15 percent above the predicted peak load. The calculation of resources in most regions includes current VIEU-owned generation and merchant plant capacity (modified by an expected forced outage rate[ww] and reduced by expected retirements), planned capacity additions (with interconnection agreements and customer contracts), renewable generation (derated to expected capacity at peak load hour),[xx] contracted imports, energy efficiency, DR, and distributed generation (derated to expected capacity at peak hour).

[vv] Forecasts of reserve margins may decline in the out-years of a projection because new resources such as power plants, demand response, and energy efficiency are not firm at the time the forecast is made. Because of the uncertainty associated with more distant years, NERC planning reserve margin determinations do not look out past 10 years.

[ww] ISO-New England reports that the expected forced outage rate for generators in their regions have increased because power plants in the region are operating under more stressed conditions. Older power plants in each region are less reliable and go out of service more often as they age. https://energy.gov/sites/prod/files/2014/10/f18/08a-REthier.pdf

[xx] Each ISO and RTO calculates the on-peak contribution of renewable resources as a function of historic resource performance. Land-based wind plants are assumed to deliver four to 14 percent of nameplate capacity during peak summer afternoon periods, and solar resources are assumed to deliver between 10 percent and 80 percent of nameplate capacity. Note, however, that as the level of PV penetration increases, the cumulative amount of PV generation on summer afternoons is moving net load peak hour later.

Figure 4.2. Five-Year Average Reserve Margins across Different Regions (2018–2022)[231]

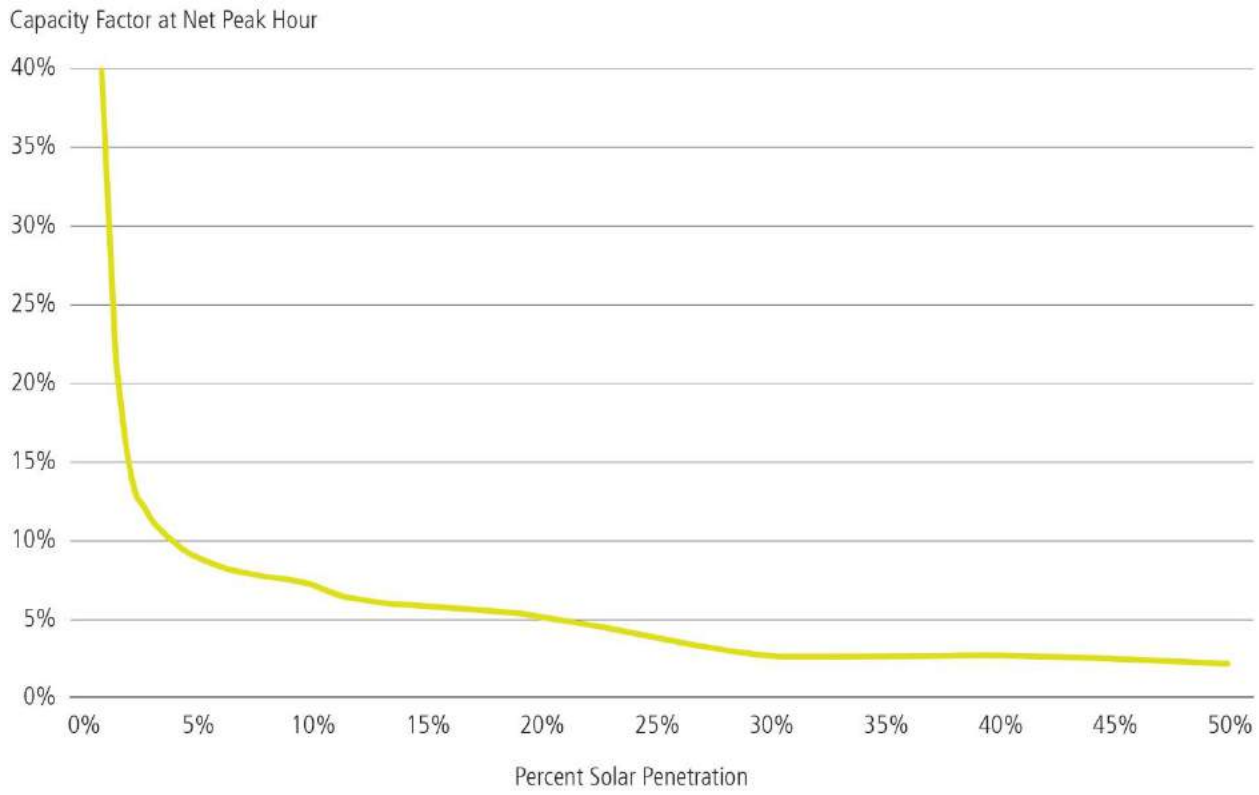


All regions have reserve margins above resource adequacy targets.

The types of resources available within a region affect the reserve margin calculation. Each type of resource has a different availability rate (based on past performance) that reflects the likelihood that it can be relied upon to be available at system peak. For instance, 1,000 MW of coal units with an on-peak availability rate of 90 percent would have a greater impact on the reserve margin than 1,000 MW of wind with an on-peak availability rate of 10 percent; in other words, the actual nameplate capacity totals underlying these reserve margin calculations are significantly higher than the reserve margins suggest. NERC and regional planning authorities are working to understand how common dependencies or failure modes, such as gas pipeline outages or a weather front affecting wind and solar performance across a wide area, could affect reserve margins. NERC and others are also studying how the on-peak hourly capacity factor (similar in concept to capacity value[yy]) of VRE changes as a function of VRE penetration, as shown for solar in Figure 4.3.

[yy] NERC defines capacity value as "the contribution of a power plant to the generation adequacy of the power system. It gives the amount of additional load that can be served in the system at the same reliability level due to the addition of the unit." http://www.nerc.com/docs/pc/ivgtf/omalley-ieee-confidential.pdf

Figure 4.3. Historical Solar On-Peak Capacity Factors in ERCOT[232]



As increased solar penetration in ERCOT shifts the net peak load further into the evening, its net on-peak capacity factor diminishes.

As the Department has previously noted, however, having an adequate planning reserve margin is necessary but not sufficient to ensure resource adequacy (see text box below):

"Rules" to Enable Reliable Operation[233]

In December 2016, DOE articulated four consolidated "rules" that must be maintained to enable reliable operation. These include the following:

1. ***Power generation and transmission capacity must be sufficient to meet peak demand for electricity.***

The power grid must have sufficient capacity available to meet the demand for electricity. Because there are uncertainties in forecasting demand and the potential for generation and transmission outages, the total amount of capacity must exceed the expected level of demand by a given fraction, termed the reserve margin, often about 15 percent.

2. ***Power systems must have adequate flexibility to address variability and uncertainty in demand (load) and generation resources.***

The level of demand changes throughout the day and from season to season. This, and the addition of variable generation such as wind and solar, places a premium on having flexible generation capacity that can change its level of output to account for changes in demand and the amount of generation from variable resources (such as when the wind stops blowing or the sun goes down).

3. ***Power systems must be able to maintain steady frequency.***

The power system uses what is called alternating current (AC), where the electricity reverses direction 60 times per second (60 hertz (Hz)). If this frequency of oscillation were to deviate significantly from 60 Hz, it could damage machines and electronics. Any mismatch between the supply and demand of electricity can cause this sort of deviation, and several mechanisms operating at different timescales are used to maintain a steady frequency.

4. Power systems must be able to maintain voltage within an acceptable range.
In addition to maintaining a steady frequency, the electric grid must also deliver electricity at a given voltage. This voltage varies throughout the power grid, with transformers used to change voltages. Maintaining the correct voltage requires the management of "reactive power," which is a property of AC electricity that allows power to flow. If the levels of reactive power are too high or too low, the voltage level can change, potentially even collapsing catastrophically.

NERC notes that traditional calculations of resource adequacy based on capacity (such as the planning reserve margin) will need to change:

> Until recently, new generators have generally added significant energy capability along with the capacity they provide. With the advent of newer energy limited technologies replacing older ones (e.g., with emerging larger penetrations of variable generation), an assumption of energy adequacy cannot be made simply on the basis of capacity adequacy. Future-looking detailed probabilistic assessments of resource adequacy (energy, capacity and operability), transmission adequacy and congestion are increasingly becoming an essential requirement, consistent with the growing penetration of variable generation, and in the changing non-renewable supply mix environment.[234]

4.1.1 Essential Reliability Services

Reliable operation of the BPS requires a suite of Essential Reliability Services (ERS). One key ERS is the control of system frequency, a parameter which NERC explains as follows:

> Each Interconnection is actually a large machine, as every generator within the island is pulling in tandem with the others to supply electricity to all customers. This occurs as the rotation of electric generating units, nearly all in (steady-state) synchronism. The "speed" (of rotation) of the Interconnection is frequency, measured in cycles per second or Hertz (Hz). If the total Interconnection generation exceeds customer demand, frequency increases beyond the target value, typically 60 Hz, until energy balance is achieved. Conversely, if there is a temporary generation deficiency, frequency declines until balance is again restored at a point below the scheduled frequency.[235]

NERC further expands on the two main types of frequency control, Primary and Secondary:

- Primary frequency control (immediate) comes from automatic generator governor response, load response, and other devices based on local (device-level) frequency-sensing control systems. In general, frequency response refers to the initial actions provided by the autonomous devices within an interconnection to arrest and stabilize frequency deviations, typically from the unexpected sudden loss of a generator or load. Primary frequency control is quick and automatic; it is not driven by any centralized control system, and it begins seconds after a system frequency event. Response to a frequency event can be provided by various sources, including generation resources, loads, and storage devices.
- Secondary frequency control (seconds to minutes) and tertiary frequency control (ten minutes and longer) -- Secondary and tertiary control are the centralized, coordinated control of generation, demand response, and storage resources, and these controls are performed

> by the system operator's energy management system over minutes to hours to balance generation and load.[236]

In addition to frequency control, NERC provides definitions for two other ERS, ramping and voltage support:

> **Ramping** – Ramping is related to frequency, but more in an "operations as usual" sense rather than after an event. Changes in the amount of non-dispatchable resources, system constraints, load behaviors, and the generation mix can impact the ramp rates needed to keep the system in balance.
>
> **Voltage** – Voltage must be controlled to protect the system and move power where it is needed. This control tends to be more local in nature, such as at individual transmission substations, in sub-areas of lower-voltage transmission nodes and the distribution system. Ensuring sufficient voltage control and "stiffness" of the system is important both for normal operations and for events impacting normal operations (i.e., disturbances).[237]

If grid voltage levels fall too low, customers connected to distribution networks may see their devices "brown out" and stop working. An area that has inadequate voltage support is vulnerable to voltage collapse, so the system must be operated such that a single contingency would not result in voltage collapse or cascading outages.

Generators provide voltage support by producing both real and reactive power. As FERC explains in its 2016 Reliability Primer:

> Power transferred along transmission lines consists of both "real" power and "reactive" power. The real power is the energy that is capable of performing work in electrical devices including industrial equipment, refrigerators, or toasters. Reactive power is needed to maintain the voltage as well as electric and magnetic fields in AC equipment, which includes air conditioners, motors, transmission lines, and other devices. Together, real power and reactive power comprise apparent power, which is measured in units of Volt-Amperes or kilo Volt-Amperes - kVA.
>
> Reactive power cannot be transmitted as far as real power and instead must be replenished locally. Moreover, a deficit in reactive power causes voltage to drop. This is seen when the lights dim as an electric motor starts. While reactive power consumed by facilities or devices tends to cause the voltage to drop, it can also be produced or injected into the system to increase voltage in what is often referred to as "voltage support." This is accomplished in a variety of ways, including by adjusting the reactive power output of generators or by activating capacitor banks or other power electronic equipment. If reactive power is not supplied promptly and in sufficient quantity, voltages decline, and in extreme cases a "voltage collapse" may result.[238]

FERC Order No. 827, issued in June 2016, revised FERC's *pro forma* Large Generator Interconnection Agreement and *pro forma* Small Generator Interconnection Agreement to eliminate the previous exemption for wind generators from reactive power requirements, thereby requiring all newly interconnecting, non-synchronous generators—including new wind generators—to provide reactive power as a condition of interconnection to the transmission system. FERC wrote:

> We therefore conclude that improvements in technology, and the corresponding declining costs for newly interconnecting wind generators to provide reactive power, make it unjust, unreasonable and unduly discriminatory and preferential to exempt such non-synchronous generators from the reactive power requirement when other types of generators are not exempt. Further, requiring all newly interconnecting non-synchronous generators to design their Generating Facilities to maintain the required power factor range ensures they are subject to comparable requirements as other generators.[239]

FERC's primary frequency response Notice of Proposed Rulemaking proposes to require new large and small generators to install, maintain and operate equipment capable of providing primary frequency response as a condition of interconnection.[240]

NERC explains the various reserve products from which grid operators obtain these ERS:

- **Frequency-Responsive Reserve:** On-line generation with headroom that has been tested and verified to be capable of providing droop […] In most cases, only portions of a, b and c in [Figure 4.4] qualify as Frequency Responsive Reserve.
- **Nonspinning Reserve:** Operating Reserve capable of serving demand or Interruptible Demand that can be removed from the system, within 10 minutes. (This is c in [Figure 4.4])
- **Operating Reserve:** That capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages, and local area protection. (This is a+b+c+d+e in [Figure 4.4]).
- **Regulating Reserve:** An amount of spinning reserve responsive to Automatic Generation Control, which is sufficient to provide normal regulating margin. (This is "a" in [Figure 4.4])
- **Replacement Reserve:** (This is d+e in [Figure 4.4]). NOTE: Each NERC Region sets times for reserve restoration, typically in the 30–90 minute range. The default contingency reserve restoration period is 90 minutes after the disturbance recovery period.
- **Spinning Reserve:** Unloaded, synchronized, resource, deployable in 10 minutes. (This is b in [Figure 4.4]). [241]

Figure 4.4. NERC Definitions of Reserves Used to Provide ERS[242]

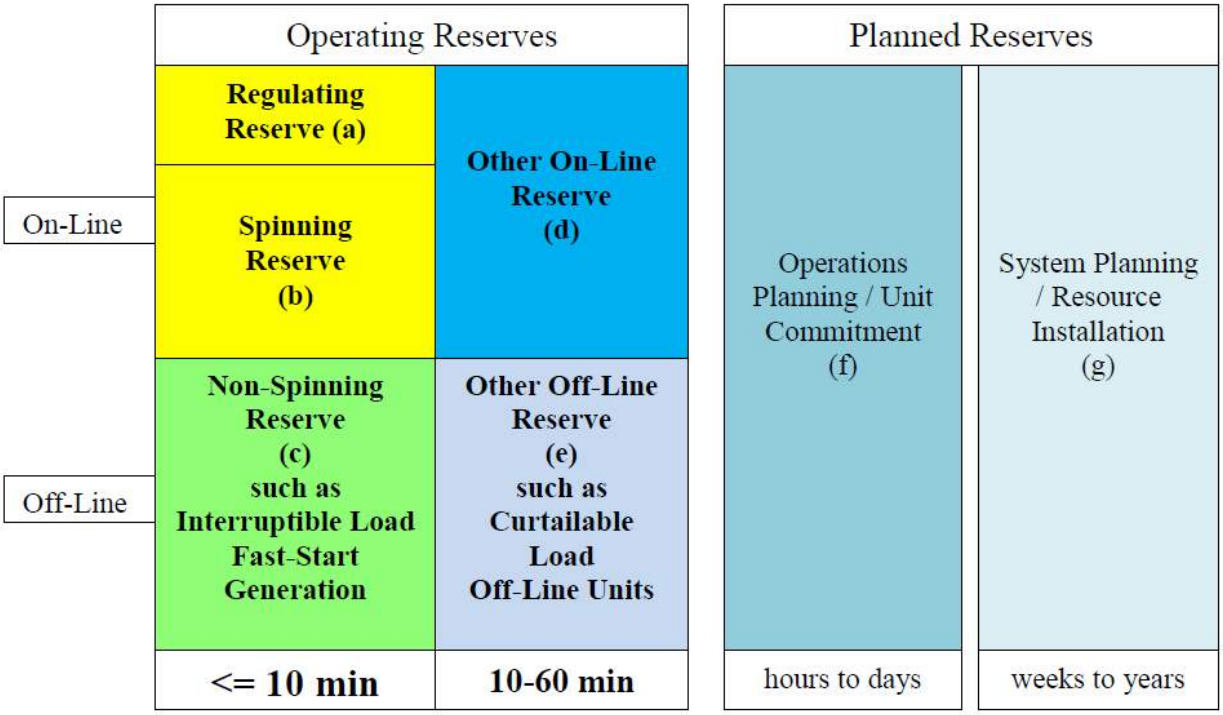
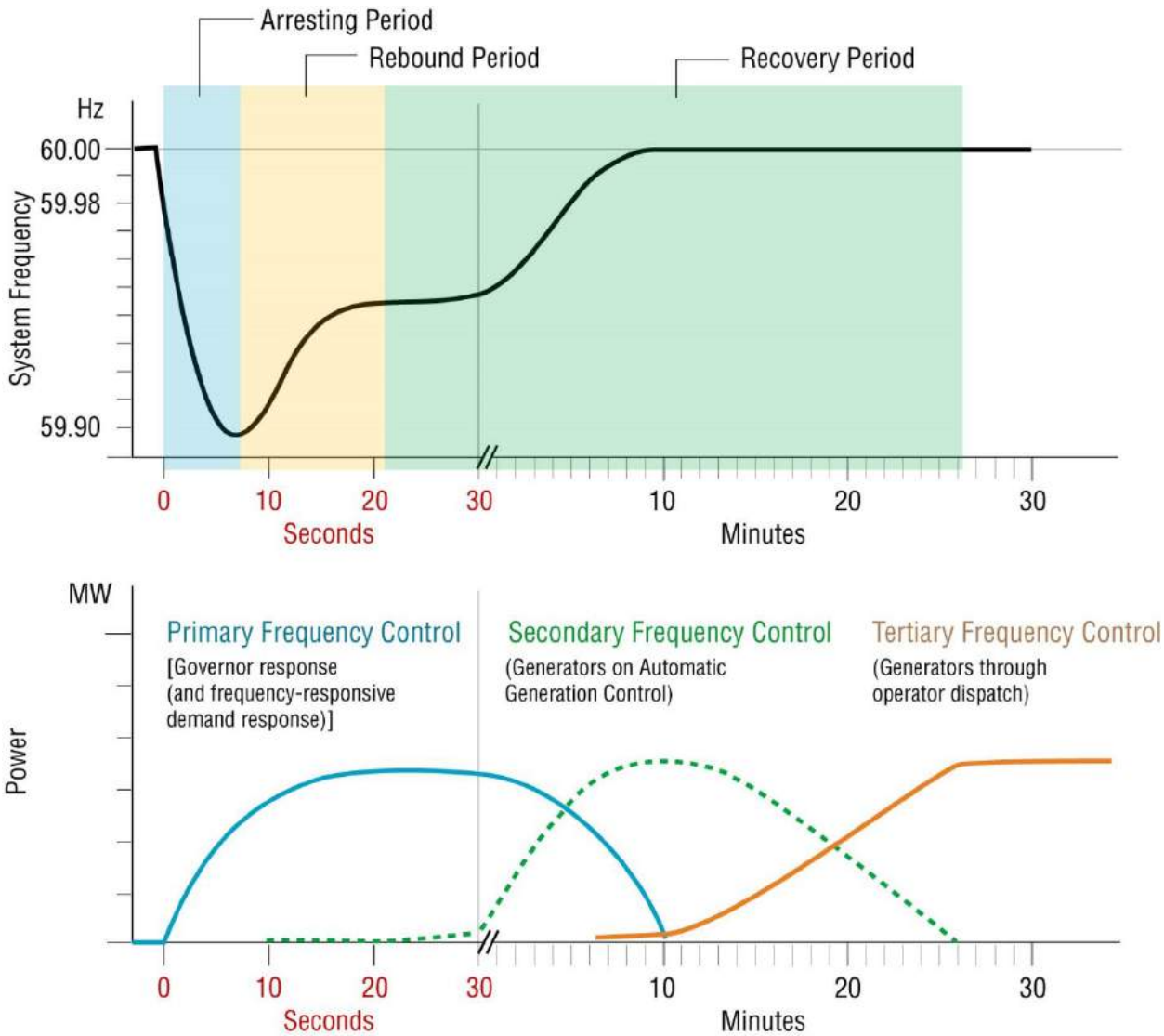


Figure 4.5 shows how system frequency falls after a major generation loss. The decline in frequency is determined by the size of the generation loss event and the availability of frequency control reserves to respond. The frequency rebound that follows is due to automated primary frequency control measures

(governor response from generators and frequency-responsive DR from customer loads controlled by relays). Secondary frequency control may derive from many sources, including from local plant controls, from a centralized control system, or from instructions issued by balancing authorities. Tertiary frequency control refers to operator-initiated, off-line resources. If these frequency management measures don't work, system frequency can keep dropping, resulting in under-frequency load shedding procedures.

Figure 4.5. System Frequency after a Grid Event (Top) and How Frequency Control Mechanisms Work to Restore Frequency (Bottom)[243]



System operators have a number of levels of frequency control to manage a significant grid event.

Not all generators can provide primary frequency control, as explained by Lawrence Berkeley National Laboratory (LBNL):

> Some generators, including all current nuclear generators, most wind turbines in North America, as well as many new natural gas turbines do not provide governor response. Other generators, which may be capable of providing governor response, are sometimes operated in ways that prevent them from providing that response. For example, a generator operated

> at its maximum capability cannot provide upward primary frequency control because it has no head room. Finally, some generators have additional controls […] that override the sustained delivery of governor response.[244]

NERC recognized several years ago that the changes affecting the grid—particularly retirement of traditional baseload capacity, increased generation from VRE, and greater use of DR and distributed generation—could create BPS reliability problems without careful study and management. In 2014, a task force under NERC's direction identified ERS as the elemental reliability building blocks from supply and demand resources that are necessary to maintain grid reliability. NERC stated that:

> To meet the needs of the future Bulk Power System, maintaining sufficient ERS will include a mix of market approaches, technology enhancements, and reliability rules or other regulatory rule changes. While the solution sets will likely be different in various regions, it may be necessary for regulators to make appropriate adjustments to market rules and reliability standards that will ensure reliable operation of the BPS.[245]

Although NERC has requirements for balancing areas,[zz] it does not require that individual generators provide primary frequency response, which involves the automatic, autonomous, and rapid action of turbine governors or equivalent controls. Further, there is no mandatory compensation for primary frequency response, though FERC Order No. 755 provides for compensation for secondary frequency response.[246] Because provision of primary frequency response may require a generator to operate at less than its full output (so it can increase power production if needed to manage frequency), standing prepared to provide frequency response services means that a generator may forgo some potential revenues.

The reliability attributes discussed above are recognized as valuable, but regional procurement and compensation for these services varies across the centrally-organized markets. In vertically integrated regions that use bilaterally organized markets, it is generally the incumbent utility's obligation to provide ERS; some interconnection agreements specify other generators' reliability service obligations if any.

4.1.2 Inertia and Inertial Response

PJM explains how conventional generators provide inertia:

> Due to electro-mechanical coupling, a generator's rotating mass provides kinetic energy to the grid (or absorbs it from the grid) in case of a frequency deviation to arrest frequency change and stabilize the electric system. The contribution of inertia is an inherent and crucial feature of rotating synchronous generators.[247]

Every operating conventional generator has mass that spins, including rotors, turbines and other masses connected to the shaft of the generator or motor. The rotating mass in each generator collectively provides inertia to help keep grid frequency at a relatively stable level, for example slowing the rate of frequency drop after a major grid event and giving other automatic controls time to act to restore frequency. Inertia also works to slow the spike in frequency that occurs after the loss of a large amount of load (for instance, if part of a city "blacks out" suddenly from a transmission or distribution failure).

[zz] NERC Reliability Standard BAL-003-1.1 establishes requirements for balancing authorities, but does not include requirements for individual generator owners or operators. However, some ISOs/RTOs, including CAISO, ISO-NE, and PJM, have implemented operating requirements for individual generating resources within their regions. Regional Reliability Standard BAL-001-TRE-01 (Primary Frequency Response in the ERCOT Region) establishes requirements for the balancing authority, generator owners, and operators in ERCOT.

Recently, manufacturers have designed electronic controls for newer model wind turbines that can provide automatic generation control, primary frequency response and synthetic inertia. General Electric (GE) notes:

> A key difference between wind inertia and fast frequency response from other resources (batteries, PV, flywheels) is that wind turbines do not need to be pre-curtailed in order to provide synthetic inertial response. Wind inertia extracts some of the kinetic energy from the spinning rotor and uses it to provide increased power output within seconds.[248]

There has not yet been much analysis of how much primary frequency response will be needed as the composition of the grid changes, nor how best to complement primary frequency response from traditional sources, such as governors, with electronics-based synthetic inertia or non-governor-based forms of primary frequency response, such as storage or DR. These are substantive engineering questions that merit further study, particularly in a future with increasing VRE levels and decreasing rotating mass-based inertia.[249]

4.1.3 Energy Storage

Energy storage will be critical in the future if higher levels of VRE are deployed on the grid and require additional balancing of energy supply and demand in real time. A few storage mechanisms such as pumped hydroelectric storage and thermal energy storage have been used for years to shift energy demand from peak to off-peak periods. A grid with higher levels of VRE and more dynamic customer loads will need more of the services that energy storage can provide by acting on both the supply and demand side, including energy, capacity, energy management, backup power, load leveling, and ERS, over periods from seconds to hours or days. However, the need for storage may not be as great for a grid more reliant on traditional baseload generation.[250]

DOE has been investing in energy storage technology development for two decades, and major private investment is now active in commercializing and the beginnings of early deployment of grid-level storage, including within microgrids.[aaa] The DOE Grid Energy Storage program notes that as energy storage technologies mature and become commercially viable, they will need to achieve the following:

- Cost competitive energy storage technology—Achievement of this goal requires attention to factors such as life-cycle cost and performance (round-trip efficiency, energy density, cycle life, capacity fade, etc.) for energy storage technology as deployed. It is expected that early deployments will be in high value applications, but long term success requires further cost reductions and the ability to monetize revenues for all grid services that storage provides.
- Validated reliability and safety— Validation of the safety, reliability, and performance of energy storage is essential for user confidence.
- Equitable regulatory environment— Value propositions for supply-side grid storage depend on reducing institutional and regulatory hurdles to levels comparable with those of other grid resources.[bbb] [251]

[aaa] Storage is an important component of most micro-grid designs reliant on VRE and is expected to play an essential role in helping customers and the BPS recover from extreme weather events (and should improve resilience and recovery following severe, high-impact events).

[bbb] A recent FERC Notice of Proposed Rulemaking seeks to identify and reduce such barriers for increased participation by energy storage in centrally-organized wholesale markets.

- Industry acceptance—industry adoption requires manufacturers to have confidence that storage will deploy as expected, and deliver as predicted and promised.[252]

Table 4-1 details DOE analysis of how energy storage options can be used to provide grid-level services.

Table 4-1. How Various Energy Storage Options Can Deliver Grid-Level Applications[253]

Application	Description	CAES	Pumped Hydro	Flywheels	Lead-Acid	NaS	Li-ion	Flow Batteries
Off-to-on peak intermittent shifting and firming	Charge at the site of off peak renewable and/ or intermittent energy sources; discharge energy into the grid during on peak periods	◑	◑	○	●	●	●	●
On-peak intermittent energy smoothing and shaping	Charge/discharge seconds to minutes to smooth intermittent generation and/or charge/discharge minutes to hours to shape energy profile	○	◑	◑	●	●	●	●
Ancillary service provision	Provide ancillary service capacity in day ahead markets and respond to ISO signaling in real time	◑	◑	◑	◑	◑	◑	◑
Black start provision	Unit sits fully charged, discharging when black start capability is required	◑	◑	○	●	●	●	●
Transmission infrastructure	Use an energy storage device to defer upgrades in transmission	○	○	○	●	●	●	●
Distribution infrastructure	Use an energy storage device to defer upgrades in distribution	○	○	○	●	●	●	●
Transportable distribution-level outage mitigation	Use a transportable storage unit to provide supplemental power to end users during outages due to short term distribution overload situations	○	○	○	◑	●	●	●
Peak load shifting downstream of distribution system	Charge device during off peak downstream of the distribution system (below secondary transformer); discharge during 2-4 hour daily peek	○	○	○	●	●	●	●
Intermittent distributed generation integration	Charge/Discharge device to balance local energy use with generation. Sited between the distributed and generation and distribution grid to defer otherwise necessary distribution infrastructure upgrades	○	○	○	●	◑	◑	◑
End-user time-of-use rate optimization	Charge device when retail TOU prices are low and discharge when prices are high	◑	◑	○	◑	◑	◑	◑
Uninterruptible power supply	End user deploys energy storage to improve power quality and /or provide back up power during outages	○	○	◑	●	●	●	●
Micro grid formation	Energy storage is deployed in conjunction with local generation to separate from the grid, creating an islanded micro-grid	○	○	○	●	●	●	●

Definite suitability for application ●; Possible use for application ◑; Unsuitable for application ○

State policies are emerging to encourage further use of energy storage technologies for grid support and energy security. California has directed its utilities to acquire 500 MW of energy storage by 2020; Massachusetts has ordered its utilities to procure 200 MWh of energy storage by the end of 2019; New York's legislators have proposed creation of an Energy Storage Deployment Program, with a 2030 procurement target; Maryland has adopted at 30 percent investment tax credit for storage facilities; and Nevada's legislature has passed a storage incentivize. These programs are generally technology-neutral and will support the use of storage at the grid-level or behind the meter (on the customer's premises).[254] [255]

4.1.4 Transmission

The transmission system is a vast engineered network that transmits electricity from generators to local substations for distribution to end-use consumers. As DOE's *Annual U.S. Transmission Data Review* (2016) states, "Transmission planning activities are undertaken to enable future reliable and efficient utilization of transmission facilities by addressing, among other things, reliability concerns, constraints, and congestion."[256] Transmission reliability is maintained by enforcing operating procedures that ensure efficient system utilization, including preventing users from transmitting more power over a line than its

rated power capacity. Transmission congestion results from the inability to dispatch the lowest-cost generation resources due to transmission constraints.

Transmission investments provide an array of benefits that include providing reliable electricity service to customers, relieving congestion, facilitating robust wholesale market competition, enabling a diverse and changing energy portfolio, and mitigating damage and limiting customer outages (resilience) during adverse conditions. Well-planned transmission investments also reduce total costs. SPP analyzed the costs and benefits of transmission projects from 2012–2014 and found that the planned $3.4 billion investment in transmission was expected to reduce customer cost by $12 billion.[ccc] This yielded an estimated benefit of $3.50 for every dollar invested in the region.[257]

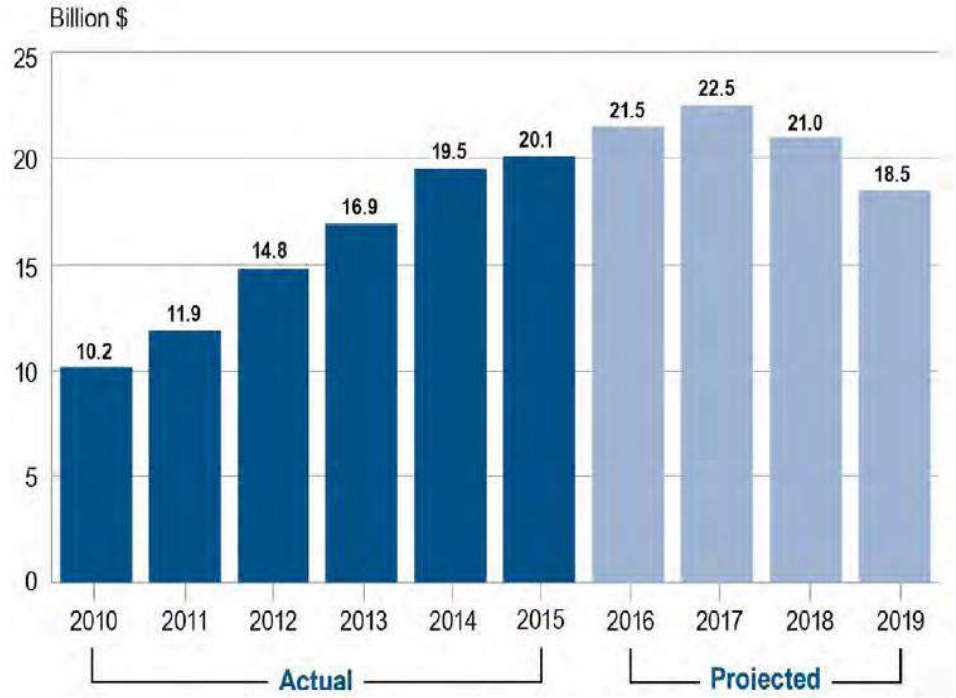
A robust transmission system is needed to provide the flexibility that will enable the modern electric system to operate. Although much transmission has been built to enhance reliability and meet customer needs, continued investment and development will be needed to provide that flexibility.

The challenge for building transmission continues to revolve around the three traditional steps involved, each of which can be time-consuming, involved, and complex: (1) demonstrating a need for the transmission project, also known as transmission planning, (2) determining who pays for the transmission project, also called cost allocation, and (3) state and Federal agency siting and permitting. FERC has taken steps to help with the first two, with reforms such as Order No. 1000, which remains a work in progress.[258] [259] [260] [261] [262] Transmission planning entities, as well as regional state-based groups, are also contributing to improving these three necessary process steps. The current and past administrations, aided by various new Federal laws, have issued various Executive Orders and other initiatives to improve the processes involved in siting and permitting of transmission when Federal lands or waters are involved.

All three transmission building steps can be time-intensive and complex; in particular, siting and permitting for large networks or long multi-state lines is challenging. [263] [264] [265] The second necessary step of cost-allocation can be time-consuming as well. For example, large overlay networks now being built in MISO ("Multi-Value Projects")[266] and SPP ("Highway/Byway Plan")[267] required several years of sensitive negotiations among states brokered by the respective Organization of MISO States and SPP Regional State Committee to determine the cost allocation of each large transmission buildout.[268] [269]

[ccc] Nearly $12 billion in net present value benefits for consumers over the next 40 years, or around $800 for each person currently served by SPP, or $2,400 per each metered customer.

Figure 4.6. EEI Historical and Project Transmission Investment (Nominal Dollars)[270]



Prudent and well planned transmission can reduce total system costs by reducing localized congestion that sometimes leads to high wholesale electricity prices at transmission-constrained nodes. Transmission investments in future years could increase as utilities and system operators seek to mitigate reliability impacts of plant closures and bring new generation to load centers.

4.1.5 System Requirements to Meet Higher Levels of VRE on the Grid

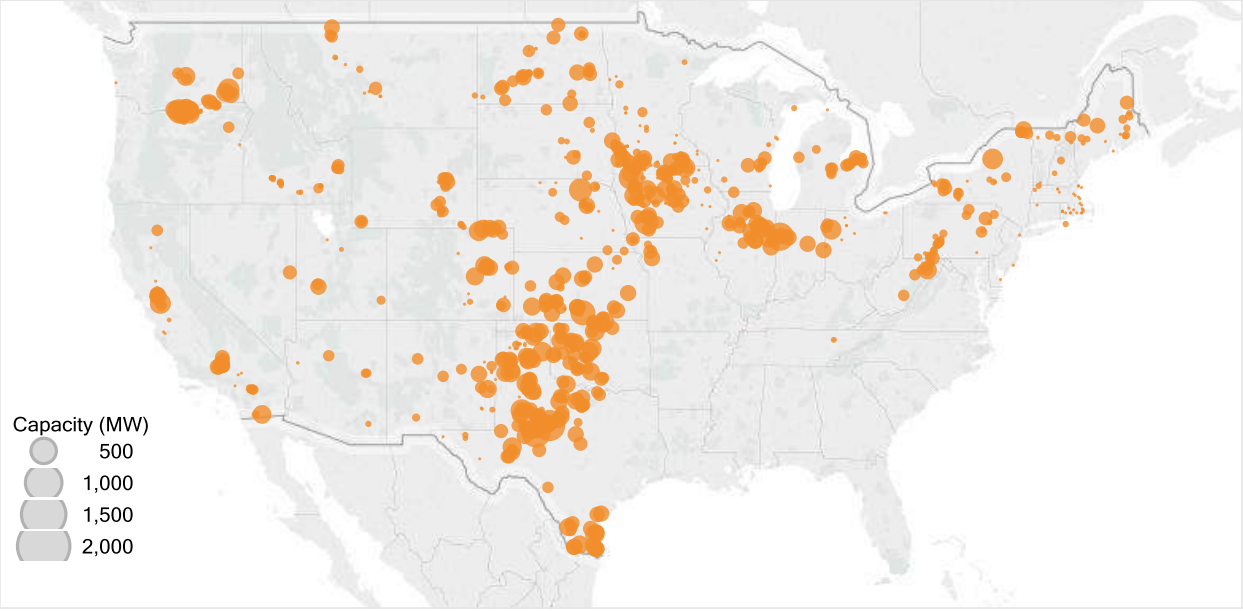
Levels of wind and solar penetration—including distributed and utility-scale installations—have grown in recent years from 0.3 percent of total annual generation nationwide in 2002 to 6.9 percent in 2016.[ddd] [271] Various integration studies (see Appendix B:) have explored grid operations at higher levels of VRE penetration (ranging from 10 percent to 60 percent) and examined the technical challenges for grid operators.[eee] These challenges can generally be met at lower levels through a number of changes to grid operation, planning, and transmission expansion practices, and with other sources of grid flexibility. Solutions vary by region, depending on existing transmission constraints, generators, sources of flexibility, and institutions and markets – each of which comes with associated implementation costs and other consequences to address. Costs can change over time as technologies and markets evolve, or

[ddd] AEO 2017 reference case indicates that this could grow to 17% by 2030.

[eee] The studies (see Appendix B) that look into the distant future are exploratory only and represent initial investigations into how to implement high levels of VRE. They do not look into all the operational aspects of reliability due to the needed complex and computationally challenging modeling. Typical assumptions (sometimes implicit) include successful siting of (at times long multistate) transmission lines and new generation, sufficient new and existing economically viable conventional generation and other resources to support the VRE, institutional and market changes, and relevant grid modernization-type spending at both the transmission and distribution level. One study, for the ease of modeling, even assumes the nation's 66 balancing authorities, including their governing boards and member states, would agree to one national joint dispatch). Some of these assumptions are non-trivial. These studies recognize that given enough time and money, power system engineers can make any resource and configuration reliable, as long as the laws of physics are not violated; whether the changes needed are indeed affordable, doable, and desirable may be a different question. Also, affordability was typically not in the scope of these studies.

as other enabling technologies such as storage mature. Grid operators and planners continually evaluate and determine how to maintain reliability as the resource mix changes and evolves.

Figure 4.7. Location of the Existing Wind Fleet[272]



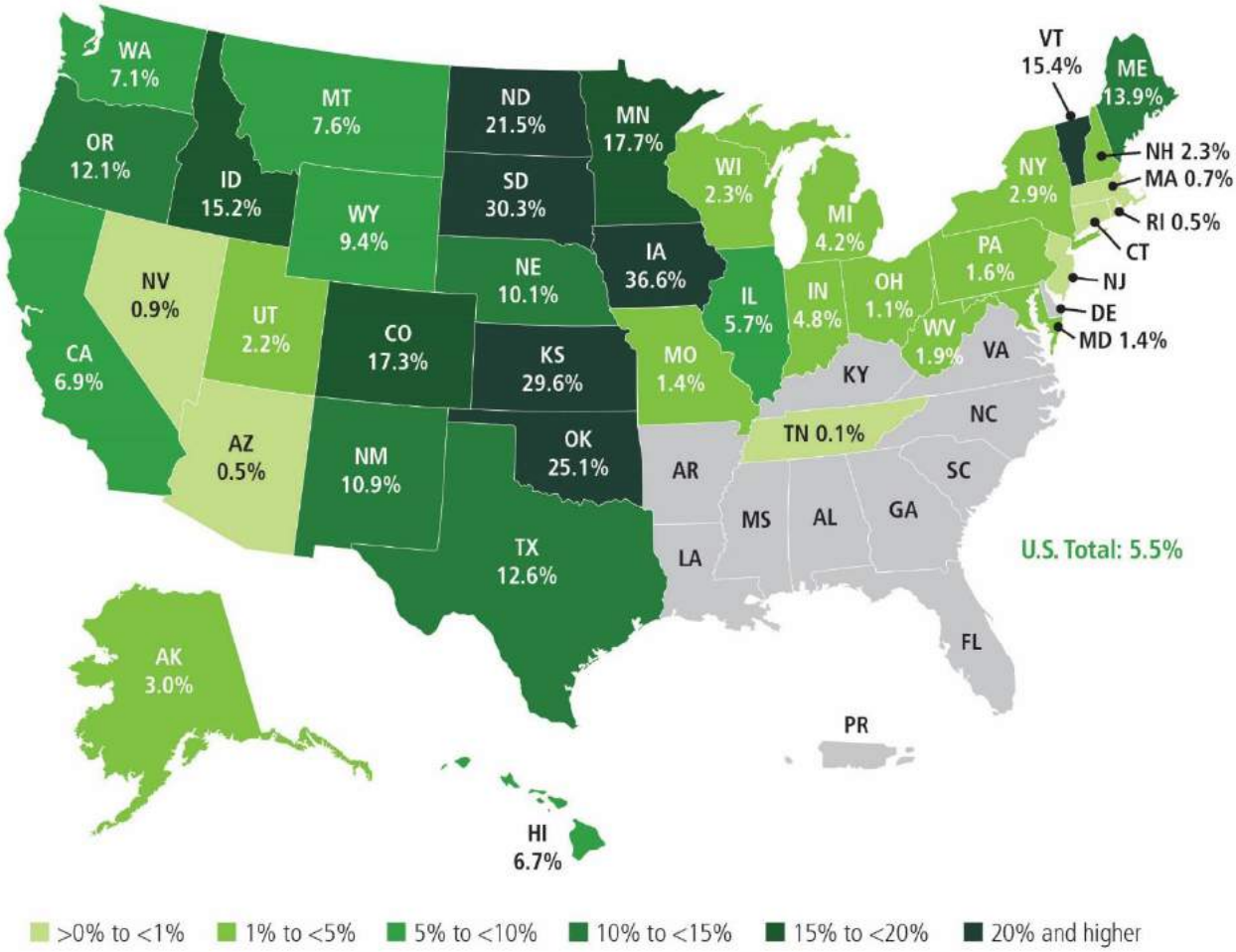
Most of the contiguous United States' wind power plants are installed in the center of the Nation, which has the best wind resources.

Total penetration of VRE is increasing rapidly in several regions, and wind represents the majority of current installed VRE. Wind turbines have contributed more than one-third of the nearly 200,000 MW of total utility-scale generating capacity added since 2007, reflecting a combination of improved wind turbine technology and lower costs, increased access to transmission capacity, state-level RPS, and Federal tax credits and grants. Distribution of wind capacity across the contiguous United States is shown in Figure 4.7.

Percentage wind generation by state is shown in Figure 4.8. In particularly windy hours, wind output in regions with significant wind capacity can be very high. On May 16, 2017, the CAISO hit a new daily renewables record when the combination of wind, solar, hydro, and other renewables served nearly 42 percent of electricity demand; during peak renewables production (the 2:00 p.m. hour), renewables supplied nearly 72 percent of electricity.[273] In Texas, at the end of 2016, ERCOT had more than 17,600 MW of installed wind capacity and 566 MW of utility-scale solar capacity.[274] ERCOT reached 50 percent wind penetration in the early morning on March 23, 2017, when load was below 29,000 MW; at 5:00 p.m. that afternoon, when peak load hit 45,391 MW, wind contributed about 30 percent to the energy needed to meet that peak.[275] SPP recently set a new wind-penetration record of 52.1 percent on February 12, 2017, the highest across North American RTOs.[ggg] [276] [277]

[ggg] On the other hand, there are times when wind generation can be low. For example, ERCOT reports that for 2016, wind generation was below 2,500 MW (approximately 15% of total operating wind capacity as of November 2016) for 17 percent of the year's hours. http://www.ercot.com/news/releases/show/113533.

Figure 4.8 Wind Energy Share of Electric Generation by State, 2016[278]



One of the greatest barriers to widespread VRE adoption is the challenge of managing its variability and corresponding impacts on net load. Table 4-2 summarizes the characteristics of VRE, the challenges to integration, and how to mitigate those challenges.

Table 4-2. Characteristics of VRE, Grid Integration Challenges, and Mitigation Options[279]

Wind & Solar Characteristics	Potential Grid Integration Challenges	Mitigation Options
Variability	Generator output can vary as underlying resource fluctuates.	In many power systems, sufficient flexibility exists to integrate additional variability, but this flexibility may not be fully accessible without changes to power system operations or other institutional factors (e.g., increased ramping of generation and improved coordination across markets and balancing areas) (Lew et al. 2013).
Uncertainty	Generation cannot be predicted with perfect accuracy (day-ahead, day of).	Integration of advanced renewable supply forecasting into dispatch and market operations has reduced uncertainties, improved scheduling of other resources to reduce reserves and fuel consumption, and enabled VRE to participate as dispatchable resources

		(IEA 2014; Lew et al. 2011). Examples: Xcel Energy, U.S. RTOs/ISOs (Porter et al. 2012).
Location specificity	Generation is more economical where highest-quality resources are available.	Competitive Renewable Energy Zones in Texas are an example of an approach to quickly develop generation and transmission in coordination (18.5 GW and 3,600 miles were completed nine years after Competitive Renewable Energy Zones legislation was signed) to access wind resources in remote parts of the state.
Non-synchronous generation	Generators provide voltage support and frequency control in a different manner than traditional resources.	Grid code requirements are evolving in response to technological advances and anticipation of high VRE penetration levels. For example, ERCOT, which is a small interconnection and more vulnerable to frequency excursions, now requires wind generators to provide inertial response, which helps keep a system stable in the initial moments after a disturbance (Bird, Cochran, and Wang 2014).
Low capacity factor	Availability of the underlying energy resource limits the run-time of the plant.	Capacity payments or markets, potentially tied to performance, could ensure sufficient cost recovery. The potential for stranded assets is not unique to VRE and can occur whenever generation with lower marginal costs is added to the system. For example, low natural gas prices have reduced the market competitiveness of nuclear plants, contributing to recent retirements (Wernau and Richards 2014).

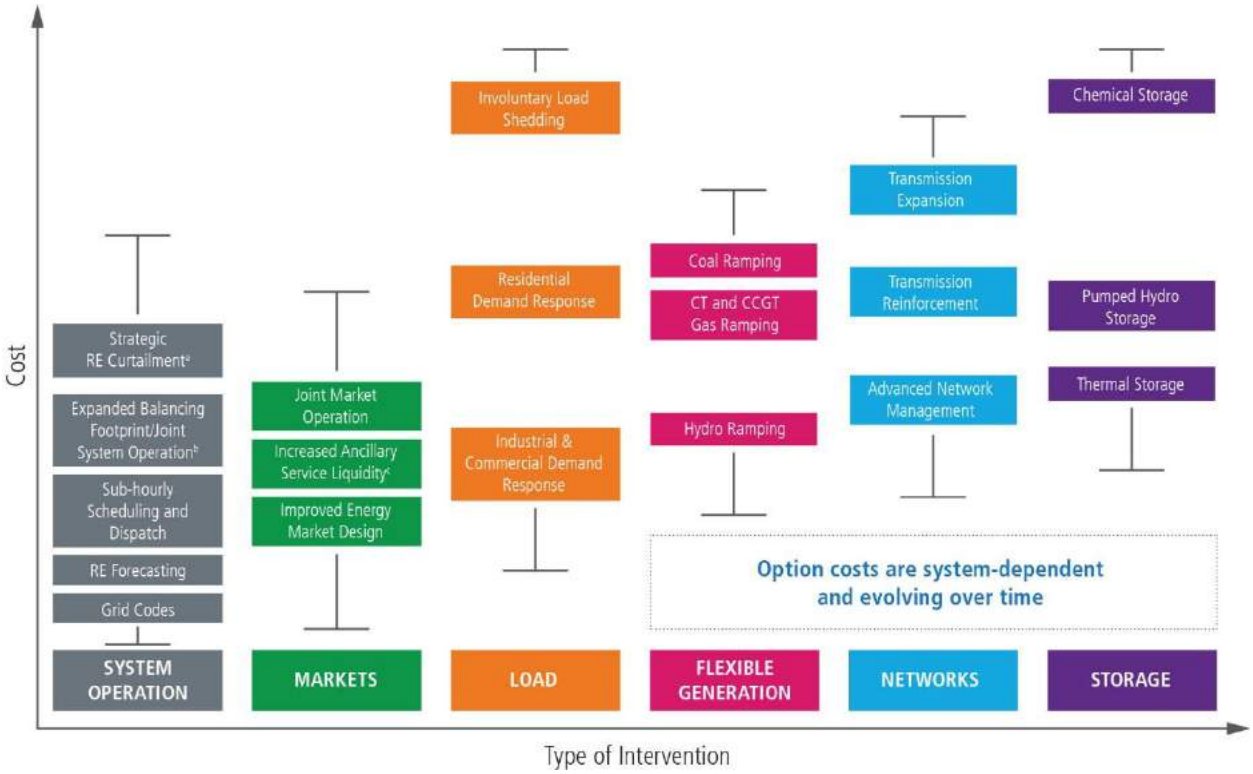
Utility-scale wind and solar plants are more location-limited than some other generation types, so they may require transmission construction to be able to interconnect with the grid and secure deliverability to customer load centers. LBNL researchers state that power systems with large or growing amounts of VRE:

> [W]ill benefit if the rest of the electricity system is flexible – able to respond to shifts in demand and VRE availability. VRE impacts and system costs will be driven lower as power systems transform to manage the unique characteristics that VRE resources introduce. Power systems that resist change as VRE penetrations increase will experience greater challenges in maintaining reliability and managing costs.[280]

Figure 4.9 shows a suite of options for integrating VRE effectively, spanning physical, operational, markets, load, and other means.[hhh]

[hhh] However, proponents of dispatchable renewables (biomass, hydro, and geothermal) argue that other approaches should also be considered. http://www.sciencedirect.com/science/article/pii/S104061901500024X

Figure 4.9. Ways To Integrate VRE, Arrayed by Type of Intervention and Cost (2014)[281]



Forecasting of VRE is a critical challenge to system operators to manage high-risk weather days. Specific issues include wind icing forecasts and weather fronts that result in low-level jet winds and other wind cut-out scenarios. Since long-term VRE forecasting is not practicable today, system operators will have to rethink outage scheduling if a region has high dependency on wind as a resource.[282]

FERC, NERC, and the RTO/ISOs have undertaken several initiatives to modify requirements for interconnecting VRE to improve grid reliability. These initiatives include early work to develop low-voltage ride-through requirements for interconnecting wind and solar generation (which are included as a requirement for wind plant interconnection under the FERC open access transmission tariff), as well as California updating its solar photovoltaic (PV) distribution interconnection requirements to include smart inverters. Other nations have grid codes that require the provision of specific ERS for new VRE resources as a condition of interconnection. And FERC and several RTOs and ISOs have sought to remove barriers to participation in organized markets by DR resources that can deliver some ERS and provide benefits to consumers.

The Bonneville Power Administration (BPA) offers a good example of managing the challenges of integrating VRE effectively using better operational and business practices. Wind generation capacity in BPA's balancing authority area grew from 250 MW to 4,782 MW within a 10-year span, driven by state RPS requirements and Federal tax credits. Much of the wind generation is located along the Columbia River Gorge, connecting to the high-voltage transmission system serving the Federal Columbia River hydroelectric plants, so the wind fleet had little diversity and could swing output as much as 1,000 MW within an hour. BPA began charging for using hydropower to balance the wind generation (also called a balancing capacity rate and since adopted by FERC for other regions), and it set a penalty rate to encourage accurate wind production scheduling. Wind forecasting and scheduling practices and tools have since improved significantly.[283]

Because wind generation receives the PTC and has PPAs that encourage production regardless of system demand, it can be economical for wind to generate even when market prices are negative. As a result, generators that are "must-run" (either for statutory or reliability reasons) must compete with resources that will generate when prices are negative. Anticipating the growing challenges posed by the changing resource mix in the region, BPA worked with stakeholders to develop the Oversupply Management Protocol to displace generation in BPA's balancing authority area and replace it with Federal hydroelectric generation that must run for endangered fish operations. Displaced generators are compensated for any costs that they incur, and BPA recovers these costs through rates to its wholesale customers.[284]

However, this over-supply situation combined with sustained low natural gas prices has continued to erode the price of wholesale power in the western wholesale market. Changes in the wholesale market may be necessary to better balance state priorities, maintain grid reliabilities, and appropriately compensate baseload and other flexible resources, such as hydropower, for the ERS they provide.[285]

The process of BPS consolidation and market cooperation among producers across a larger electric market and operational region has been shown to smooth out VRE output variability. MISO found that

> [T]here are significant benefits from the geographic diversity of wind generating facilities and the size of the MISO operating footprint. The large number of individual turbines and plants, spread across a large geographic area with dimensions in the hundreds of miles, results in statistical smoothing of production changes driven by local meteorological effects. Large changes in aggregate production are driven by large-scale meteorological phenomena such as weather fronts, and occur over longer timescales from many tens of minutes to several hours.[286]

4.1.6 Impact of VRE on Net Load

More than 60 percent of all utility-scale electric generating capacity that came online in 2016 was from wind and solar technologies.[287] In March 2017, wind and solar accounted for 10 percent of total U.S. electricity generation, up from 7 percent for the whole of 2016.[288] The increase in VRE has altered grid operation in some regions and the way dispatchable generation and DR are used to protect the grid and meet loads.

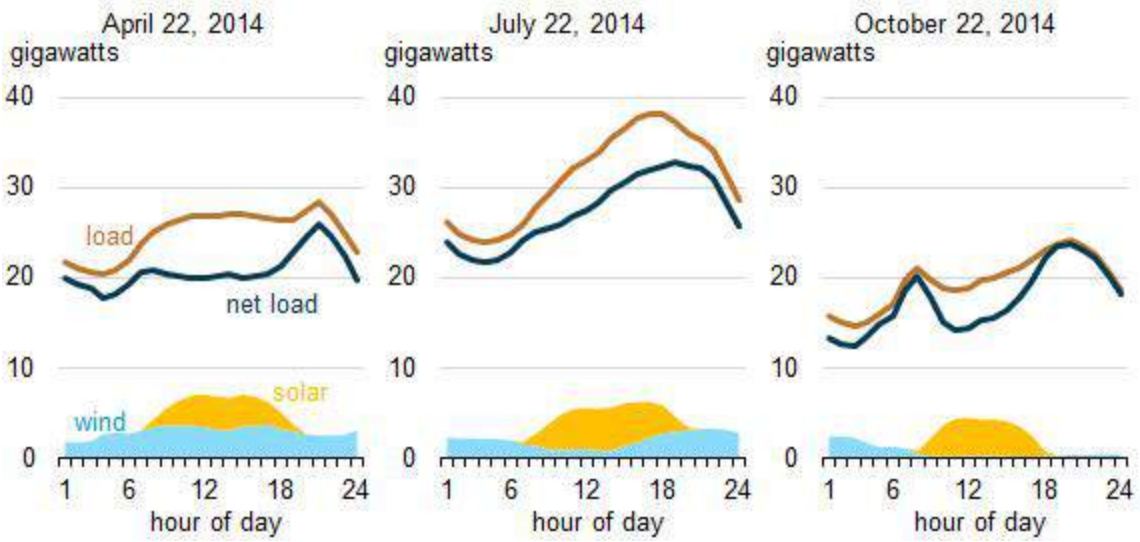
The Western Area Power Administration (WAPA), a Federal power marketing agency, operates 8,000 MW of hydroelectric generation and three balancing areas in 15 states across the West. WAPA sums up the operational changes and challenges for grid managers facing VRE, variable loads, and a variety of generation types with differing capabilities and constraints:

> Generation operators, including VERs [Variable Energy Resources], must coordinate with their host Balancing Authority (BA) to ensure that their output continuously matches load. Generation is adjusted throughout the day to meet scheduled output and is made available to regulate moment variations intra-hour. For VERs when the wind drops off or clouds pass over a solar array, less energy may be produced than scheduled (over-scheduled/under-produced), and additional resources must be brought on-line to make up the difference. There is a cost associated to these added generation resources. Similarly, if VERs are producing more than what was scheduled, or if electrical demand is less than anticipated, other resources must be backed down to ensure resources and load are balanced. Not all generation is capable of responding. Traditional generation, like coal, is not capable of reacting quickly to changing needs and takes hours or days to reach full operating potential. Gas turbines can react fairly quickly, but only if the plants are not already producing at full rated generating capacity. Hydro generation, while being an ideal resource to help with VER

integration, is generally scheduled to meet reservoir requirements or provide for downstream water demands, including fish, wildlife, and other environmental mitigation requirements.[289]

To illustrate how VRE can increase the need for flexibility, Figure 4.10 demonstrates how VRE impacts system operations. The figure introduces the concept of "net load"—electricity demand minus VRE generation—which represents the demand that must be supplied by the conventional generation fleet if all VRE is to be utilized. The dark orange line in the graph represents total demand and shows the daily variability of demand on an hourly basis. The light blue area shows wind energy, and the yellow area shows solar energy. The dark blue line represents the demand (less VRE) that must be supplied by the remaining generators, assuming no curtailment of wind energy. The graph shows that often the output level of the remaining generators must change more quickly and be turned up or down inversely with VRE production.

Figure 4.10. CAISO Load, Net Load, and Wind and Solar Output on Example Weekdays during 2014[290]

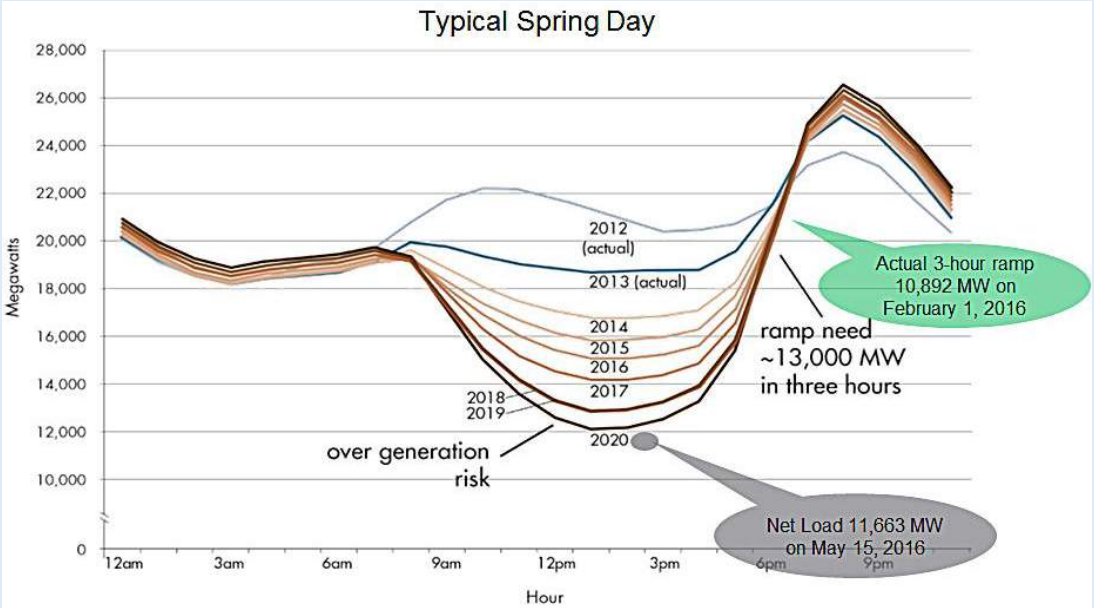


CAISO data show the effect of VRE on net load (total customer load minus wind and solar output) during representative days in the spring, summer, and fall. As the amount of VRE generation increases, daily net load decreases, and the impacts on net load become more acute in shoulder months.

In regions with high penetration of VRE, sharper fluctuations in net load require increased flexibility (ramping up and down) from conventional sources. While the resulting 'duck curve' of daily net load has so far been limited to regions such as California and the Southwest where solar generation is highest, other regions such as the Carolinas are beginning to see similar net load patterns.[291]

What the Duck Curve Tells Us About Managing a Green Grid[292]

Figure 4.11. The CAISO Duck Curve



The electric grid and the requirements to manage it are changing… The ISO created future scenarios of net load curves to illustrate these changing conditions. Net load is the difference between forecasted load and expected electricity production from variable generation resources. In certain times of the year, these curves produce a 'belly' appearance in the mid-afternoon that quickly ramps up to produce an "arch" similar to the neck of a duck — hence the industry moniker of 'The Duck Chart.'

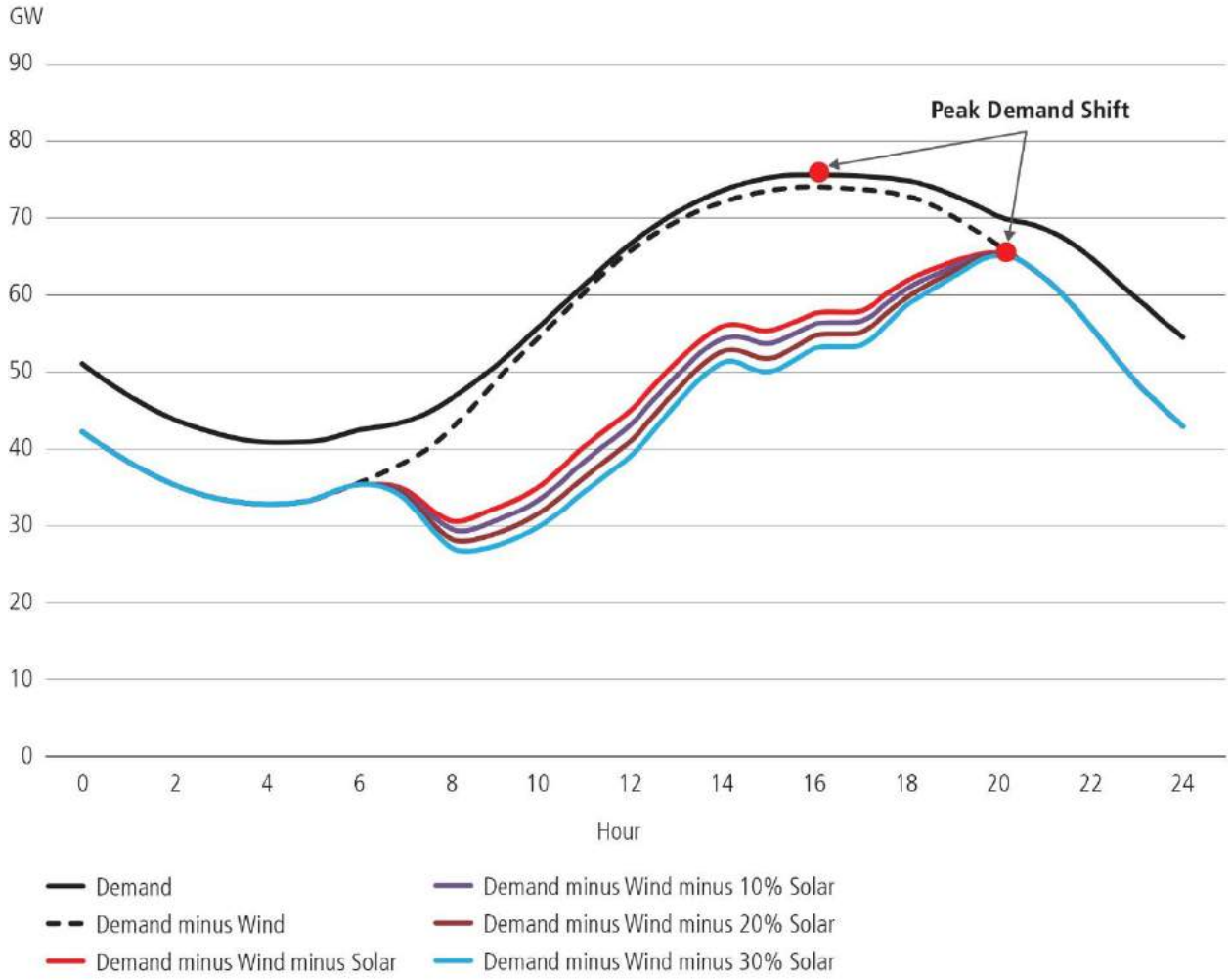
…[S]everal conditions emerge that will require specific operational capabilities:

- Short-steep ramps – when the ISO must bring on or shut down generation resources to meet an increasing or decreasing electricity demand quickly, over a short period of time;
- Oversupply risk – when more electricity is supplied than is needed to satisfy real-time electricity requirements; and
- Decreased frequency response – when less resources are operating and available to automatically adjust electricity production to maintain grid reliability."

[…] To ensure reliability under changing grid conditions, the ISO needs resources with ramping flexibility and the ability to start and stop multiple times per day […] Addressing concerns about frequency response capabilities in times of low load and high renewable generation may require operating renewable generators such that they can increase power with automated frequency response capability.

At some level of penetration of distributed PV, the collective amount of PV will shift the time of peak load net of solar generation away from its previous point to later in the evening when insolation (and therefore PV production) is lower, as shown by NERC in Figure 4.12.

Figure 4.12. Demand and Net Demand Shapes at Different Distributed Energy Resource Penetration Levels[293]



To date, RTOs and ISOs are working hard to integrate growing levels of VRE through extensive study, deliberate planning, and careful operations and adjustments.

The Role of Technical Standards and Grid Codes for Effective VRE Integration

Several types of standards apply to VRE and other generation. Interoperability standards define basic technical and engineering performance requirements, such as the Institute of Electrical and Electronics Engineers Standard 1547, which defines uniform requirements for the performance, operation, testing, safety, and maintenance of interconnection between distributed generation resources and the grid. Regulatory requirements such as FERC's *pro forma* open access transmission tariff (including interconnection requirements) dictate further reliability and performance terms for generators. As the level of installed wind and solar generation has grown, early technical requirements and standards for wind and solar have required updates to ensure performance under disturbance conditions.

The examples described below illustrate the need to evolve standards as the penetration of non-synchronous generation increases.

- In August 2016, the Blue Cut wildfire crossed a major transmission corridor in Southern California, resulting in 15 line faults. One of these faults caused the near-instantaneous loss of

1,200 MW of utility-scale PV in Southern California. Approximately 700 MW of this loss occurred when PV inverters tripped due to a "perceived, though incorrect, low system frequency condition."[294] Another 450 MW of this loss occurred when system voltage fell below the low-voltage ride-through setting of the inverters—resulting in "momentary cessation."[295] The subsequent NERC disturbance report determined that 11 similar inverter events occurred between August 16, 2017 and February 6, 2017, and NERC made several recommendations with respect to inverter settings and standards that would prevent or mitigate these events.[296]

- Australia's Renewable Energy Target has achieved significant VRE use; 35 percent of South Australia's generating capacity is wind-powered. On September 28, 2016, severe weather resulted in multiple faults on the South Australian transmission system. A number of faults in quick succession caused 456 MW of wind generation to trip off-line within approximately seven seconds as a result of a protection feature that disconnects or reduces wind turbine output when the number of low-voltage ride-through events in a specific time period exceeds a predefined limit.[297] This loss of generation increased imports from the AC interconnector until protective relays activated, islanding South Australia. Unable to rapidly shed load to match the reduced supply, the islanded region experienced a blackout. The Australian Energy Market Operator's report on the incident noted the role of changes in the fuel mix: a low amount of synchronous generation dispatched—and hence low inertia—at the time of the event resulted in a faster frequency change than had previously been experienced during separation events.[298] The report produced a list of 19 recommendations, including changes to operating procedures, regulations, and performance standards.
- The German *Energiewende* initiative encouraged high levels of wind and distribution-level solar installations, leading to over-generation and the need for VRE' curtailment in some hours. The grid technical code in place at the time required PV inverters to immediately disconnect from the grid if system frequency increased from nominal 50 Hz to 50.2 Hz. However, Germany discovered that the combination of this technical code and the growing amount of distribution-level PV capacity heightened the risk of some excess PV generation causing all PV capacity to disconnect simultaneously and create severe under-frequency conditions, potentially causing rolling blackouts and grid collapse.[299] In response, Germany modified its standards to require inverter retrofits with different low-frequency performance requirements.[300]

4.1.7 Mapping Reliability Attributes to Generation Resources

To assess its changing resource mix, PJM developed a matrix of reliability attributes needed to maintain reliable grid operation under its operating procedures (see Figure 4.13). Ultimately, a diverse generation portfolio is necessary to provide the reliability attributes discussed in this section.

Figure 4.13. Mapping Reliability Attributes Against Resources[iii] [301]

● = Exhibits Attribute
◐ = Partially Exhibits Attribute
○ = Does Not Exhibit Attribute

Resource Type	Essential Reliability Services (Frequency, Voltage, Ramp Capability)					Fuel Assurance		Flexibility			Other		
	Frequency Response (Inertia & Primary)	Voltage Control	Ramp										
			Regulation	Contingency Reserve	Load Following	Not Fuel Limited (> 72 hours at Eco. Max Output)	On-site Fuel Inventory	Cycle	Short Min. Run Time (< 2 hrs.)/ Multiple Starts Per Day	Startup/ Notification Time < 30 Minutes	Black Start Capable	No Environmental Restrictions (That Would Limit Run Hours)	Equivalent Availability Factor
Hydro	●	●	●	●	●	○	◐	●	●	●	●	◐	●
Natural Gas - Combustion Turbine	●	●	◐	●	◐	●	○	●	●	●	●	◐	◐
Oil -Steam	●	●	●	●	●	●	●	●	○	○	○	○	◐
Coal - Steam	●	●	●	●	●	●	●	◐	○	○	○	◐	◐
Natural Gas - Steam	●	●	●	●	●	●	○	●	○	○	●	◐	◐
Oil/ Diesel - Combustion Turbine	●	●	○	●	○	○	●	●	●	●	●	○	◐
Nuclear	◐	●	○	○	◐	●	●	○	○	○	○	◐	●
Battery/ Storage	◐	◐	●	●	○	○	○	●	●	●	◐	●	●
Demand Response	○	○	◐	◐	◐	◐	◐	●	●	◐	○	●	●
Solar	◐	◐	○	○	◐	○	○	●	●	●	○	●	●
Wind	◐	◐	○	○	◐	○	○	●	●	●	○	◐	●

Conventional generation sources—particularly hydroelectricity, combustion turbines (natural gas and oil), and steam turbines (oil, coal, and natural gas)—performed very well against most of PJM's reliability requirements. Nuclear units are not optimized for significant flexibility or ramping capability, but do exhibit strong fuel assurance[jjj] attributes. Batteries and storage meet all flexibility requirements, and DR offers high flexibility and ramping management capability. Wind and solar are highly time dependent and do not offer fuel assurance on their own, but can offer good flexibility if they have the proper controls and contractual arrangements.

The Electric Power Research Institute (EPRI) summarizes how regional grid operators use centrally-organized markets to procure specific reliability attributes from generators:

[iii] Combined-cycle plants are included in the Natural Gas – Steam group.

[jjj] Fuel assurance is the resource portfolio's ability to access sufficient fuel to meet system needs and maintain reliability; aspects of fuel assurance include onsite fuel storage, as well as a generator's access to sufficient fuel supplies through markets or bilateral contracts.

Ancillary Services in Centrally-Organized Markets[302]

… [E]ach ISO also operates auction markets for spinning, non-spinning reserves, and regulation with uniform clearing prices, with additional performance payments for regulation. (ERCOT, however, does not offer performance payments). Table 2 [Figure 4.14 on the following page] presents some of the terminology and characteristics. The hourly requirements for these services are set based on reliability standards and operational requirements that vary by ISO. The market designs generally co-optimize energy and reserves. Although ancillary service market designs can be complicated, the level of procurement typically only comprises less than 2% of total market volume. Ancillary service pricing is also used to signal short-term supply shortages. Because procurement of these ancillary services is allowed to be deficient before load is curtailed, the failure to procure sufficient reserves is often a first indicator of supply shortage. Hence, the ISOs include administrative scarcity prices in the market designs. Such pricing allows ancillary service prices—along with energy prices, when opportunity costs are included—to increase during shortages to levels more consistent with the value of lost load than the energy market offer caps. These scarcity prices are established differently in each ISO.

There are a number of recent initiatives to modify the ancillary service markets. CAISO and MISO have recently implemented types of ramping reserves, intended to increase the ramping range from committed resources available during real-time energy dispatch. Some ISOs, notably ERCOT, have also begun to develop designs for frequency-responsive and inertial response reserve markets.

Two ancillary services—voltage support/reactive power and black start services—are not yet considered to have the appropriate characteristics for competitive markets and are thus compensated through cost-based rates.

Figure 4.14 Selected Ancillary Service Market Design Characteristics

	ISO-NE	NYISO	PJM	MISO	SPP	ERCOT	CAISO
Regulation							
Product name	Regulation	Regulation	Regulation	Regulation	Regulation up, Regulation down	Regulation service	Regulation up, Regulation down
Performance component name (details in Table 3-12)	Regulation service	Regulation movement	Regulation performance	Regulating mileage	Regulation-up mileage, Regulation-down mileage	N/A	Regulation mileage up Regulation mileage down
Day-ahead procurement		✓		✓	✓	✓	✓
Real-time procurement	✓	✓	✓	✓	✓		✓
Contingency Reserves							
Product name—spinning reserve	Ten-minute spinning reserve (TMSR)	Spinning reserve	SR	Spinning reserve	Spinning reserve	Responsive reserve	Spinning reserve
Product name—non-spinning reserve and supplemental reserve	Ten-minute non-spinning reserve (TMNSR); Thirty-minute operating reserve (TMOR)	Non-spinning reserve	Non-synchronized reserve (NSR)	Supplemental reserve	Supplemental reserve	Non-spinning reserve	Non-spinning reserve
Forward (pre-day-ahead) procurement	✓						
Day-ahead procurement		✓	*	✓	✓	✓	✓
Real-time procurement	✓	✓	✓	✓	✓		✓

Continued on next page

Figure 4.15. Ancillary Service Products Exchanged in the Centrally Organized Markets, Listed by RTO/ISO and Category of Ancillary Service

	ISO-NE	NYISO	PJM	MISO	SPP	ERCOT	CAISO
Product name—ramp reserve				Ramp capability			Flexible ramping product
Ramp reserve—when procured				DAM and RTM			FMM and RTM (not DAM)
Voltage control—payment mechanism provision and capability	Lost opportunity cost and American Electric Power (AEP) method	Lost opportunity cost and fixed tariff rate	Lost opportunity cost and AEP method	Lost opportunity cost and AEP method	Compensation rate for provision	Lost opportunity cost for provision	Provision payment based on lost opportunity cost or contract
Black start service payments	Paid standard black start rate or station-specific rate	Paid cost-based rates	Receive revenue based on 110% of annual black start costs	Receive cost-based rate after committing to 3-year period	Not procured through SPP	Procured through bi-annual competitive process	Contracted through reliability contracts

Note: ("DAM" = day-ahead market; RTM = real-time market)

Several flexibility options are available to grid operators, such as DR, fast-ramping natural gas generation, and energy storage. As stated in QER 1.2:

> A recent study of the value of fast-ramping gas for supporting variable renewables noted that, '…to date FRF [fast ramping fossil] technologies have enabled RE [renewable energy] diffusion by providing reliable and dispatchable back-up capacity to hedge against variability of supply... renewables and fast-reacting fossil technologies appear as highly complementary and… should be jointly installed to meet the goals of cutting emissions and ensuring a stable supply.'[303]

In addition to existing sources of flexibility and reliability services, there is a growing understanding of the abilities of VRE to economically contribute to grid flexibility and reliability through operational changes and advanced power electronics. Recent technology advancements now enable wind plants to provide nearly the full spectrum of ERS (synthetic inertial control, primary frequency control, and automatic generation control). Similarly, for PV, CAISO, First Solar, and NREL recently demonstrated a First Solar 300 MW PV plant that provides active and reactive power controls, plant participation in automatic generation control, primary frequency control, ramp rate control, and voltage regulation.[304]

A recent NERC assessment on reliability in the BPS noted that DR can enhance system flexibility and reliability by providing, "regulation, governor response, spinning reserve, non-spinning reserve, and supplemental operating reserve[. F]or example, ERCOT obtains half of its spinning reserves from DR and is considering a DR-based Fast Frequency Response Service that is positioned between inertia and governor response."[305] Consumer end uses—including building energy management systems, as well as water and space heating and cooling—can also serve as DR resources using load control and communicating technologies to ramp their consumption up or down in order to support VRE integration.[306]

Demand-side flexibility via "smart charging" plug-in electric vehicles is another potential source of grid flexibility. This involves a utility or some other centralized entity remotely controlling the charging patterns of participating vehicles and/or charging stations. An aggregated fleet of vehicles or chargers can act as a DR resource, shifting load in response to price signals or operational needs; for example, vehicle charging could be shifted to the middle of the day to absorb high levels of solar generation and

shifted away from evening hours when solar generation disappears and system net load peaks. Research in this area is currently underway at the national laboratories.[307]

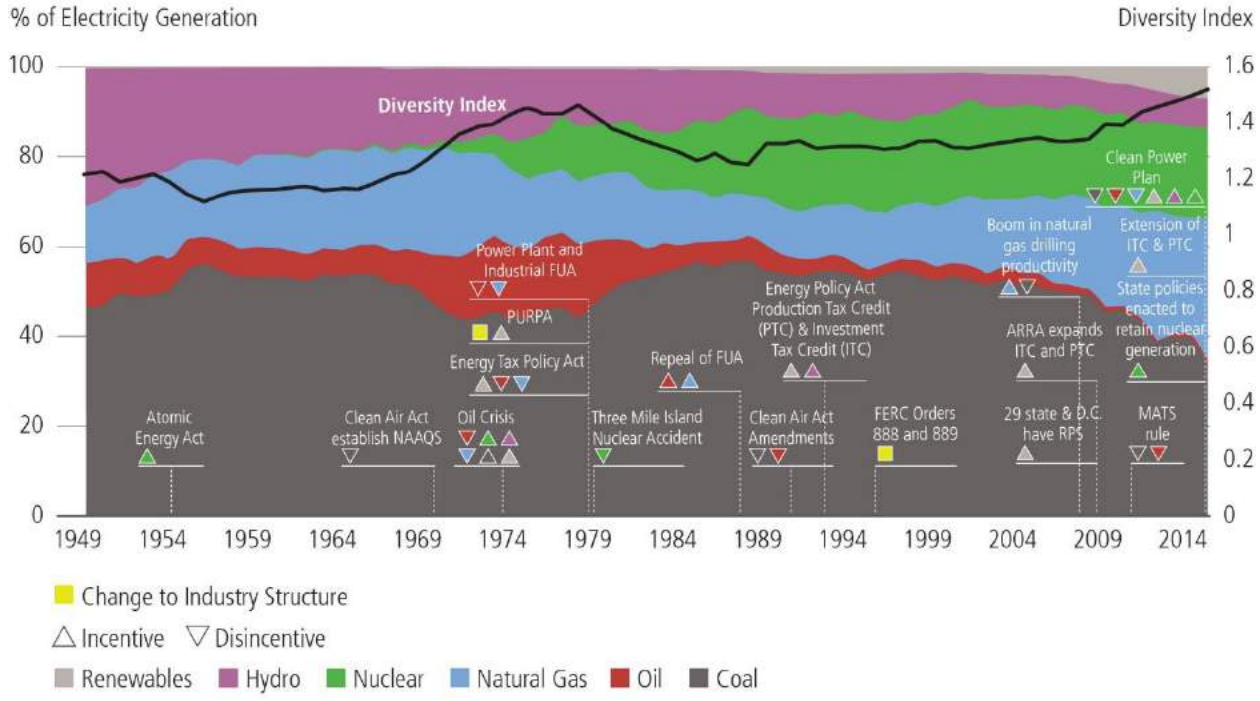
4.2 Diversity, Fuel Assurance, and Onsite Storage

The April 14 memo raises the questions of whether the diversity of the generation resources in the electric system has diminished and whether this is a problem for grid reliability and resilience. In fact, when looked at nationally, the electric system is more diverse today than it was 20 years ago, although increased national diversity does not necessarily mean diversity has increased in all regions. A holistic view of reliability and risk management, however, must include both diversity and fuel assurance.

4.2.1 Fuel Diversity

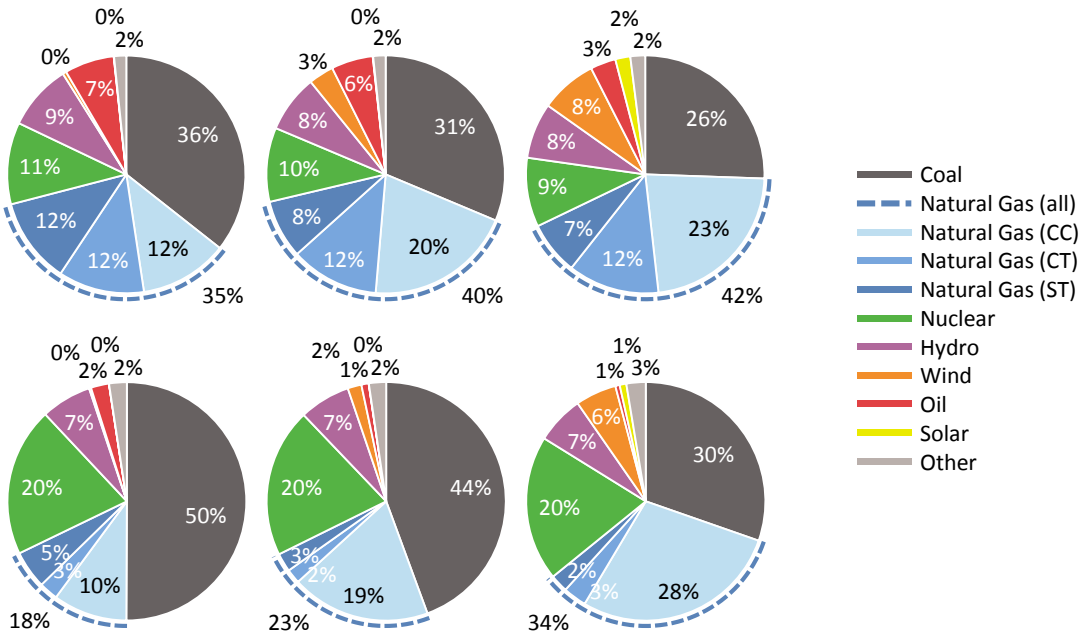
The U.S. generation mix has continually evolved as changes in technology, economics, government policy, and geopolitical forces affected the relative availability, economics, and feasibility of competing energy sources. PJM documents this evolution in Figure 4.16, which also displays a diversity index showing increasing diversity levels from about 2000 through 2014. PJM observes that, "government policy has played a major role in the development of generation resources, including policies that focused on energy security, jobs, environmental protection and conservation."[308] The chart shows how the mix of U.S. electricity use has moved in cycles for decades—how the generation share of hydroelectric facilities (most built with Federal funds during the 1930s and 1940s) declined as coal and natural gas grew (helped with funding from low-cost Federal land and mineral leases); how nuclear generation grew (aided by Federal policy and funding assistance) in the 1960s; how nuclear energy displaced hydroelectricity and natural gas-fired electricity in the 1970s; and how coal, nuclear, and natural gas-fired electricity have displaced oil-fired generation since the 1980s.

Figure 4.16. Generation Mix and Various Economic and Policy Drivers Since 1949, Including Diversity Index[309]



Closely tracking the PJM trends, the national picture of the resource mix shows coal and oil being displaced by gas and VRE. In addition to this, Figure 4.17 shows how the national U.S. capacity and generation mix have become more diverse over time. Changes in capacity (top) have moved the resource mix toward a greater proportion of natural gas, wind, and solar, while coal and oil capacity have decreased. Energy generation trends for these resources (bottom) have tracked changes in capacity, with natural gas generation almost doubling in proportion. While nuclear capacity has decreased relative to other resources, the proportion of nuclear generation remains unchanged as capacity factors for nuclear units have increased

Figure 4.17. Changes in U.S. Capacity (Top) and Generation (Bottom) Mix over Time (Left to Right: 2002, 2009, 2016)[310]



The grid was, on average, more diverse in 2016 than in 2002 in terms of both capacity and generation.

Diversity can be a useful tool for managing both reliability and financial risks. For the power system, developing and maintaining a portfolio of diverse generation, storage, and demand-side options can be useful for system planners and operators in creating optionality and hedging risks. Physical and financial risks can also be managed and hedged using reliability standards, operating rules, and financial markets and contracts. Better system diversity with greater use of domestic energy sources enhances U.S. energy security. However, greater fuel diversity does not *always* translate to increased system reliability.

Risk, Reliability, and Fuel Diversity[311]

In a summary of the policy implications of the impacts of fuel diversity on risk and reliability, Devin Hartman of the R Street Institute states that:

Policymakers and regulators should recognize that fuel diversity is a poor proxy for valid policy objectives, like risk management and reliability. Specifically, a high level of fuel diversity does not necessarily mean that an electricity system manages risk efficiently or meets reliability needs. Conversely, policies or market-design changes intended to increase fuel diversity will not necessarily improve risk management or reliability.

Fuel neutrality is essential for both monopoly-utility resource planning and competitive markets to manage risk and achieve reliability efficiently. Interventions to promote specific fuel types—such as

bailouts for coal and nuclear or mandates and subsidies for renewables—skew investment risk and can undermine incentives for reliability-enhancing behavior (e.g., a public intervention to finance pipeline expansion removes incentives for the private sector to invest in fuel security). Fuel-specific subsidies and mandates replace individual choice with collective choice. This one-size-fits-all approach to risk mitigation ignores variances in individuals' risk tolerances, results in high-cost risk mitigation, and creates perverse incentives for market participants by transferring risk and costs from the private to the public sector.

For regulators, attempts to achieve fuel diversity in market designs explicitly would likely result in inefficient and potentially discriminatory practices that are inconsistent with the Federal Power Act. The reliable performance of power generators varies across and within fuel types and changes with fluctuating conditions. This renders any attempt to value fuel diversity very complex. It would require extensive administrative judgment, expanding the potential for government failure. Ultimately, the central aim of market design should remain to procure specific reliability attributes at the least cost.

4.2.2 Fuel Assurance and Onsite Storage

FERC uses the term fuel assurance to mean a generator's access to sufficient fuel supplies through markets or bilateral contracts (and the degree to which those arrangements are firm). On the RTO/ISO level, fuel assurance refers to the regional resource portfolio's ability to access sufficient fuel to meet system needs and maintain reliability.[312] [313]

NERC's 2017 *State of Reliability* report identified "lack of fuel" among the top ten causes of forced outages for 2014 and 2015.[314] While lack of fuel is a relatively infrequent cause of generator outages, it can still have major repercussions when it does occur because system fuel supply chain disruptions can impact many generators during a single widespread fuel shortage event. Nuclear and coal plants typically have advantages associated with onsite fuel storage compared to natural gas. While having fuel onsite reduces the risk that a generator will be unable to operate when needed, every type of fuel and power generation source has known vulnerabilities that can compromise its ability to perform reliably.

Valuation or regulation of onsite fuel storage varies across the Nation's organized markets. Onsite fuel supplies can be required, incentivized, or not compensated—depending on the RTO/ISO in question. For example, some dual-fuel generators in the New York City region (NYISO Zone J) are required under local reliability rules to maintain onsite fuel to protect against the loss of gas supplies.[315] Several markets have also attempted to incentivize firm and onsite fuel supplies by adding performance requirements to their capacity markets. In PJM and ISO-NE, these requirements were adopted after generator underperformance occurred during several instances of system stress between 2010 and 2014.[kkk] The incentives in these markets are designed to reward or penalize generators based upon how they respond to the system operator during performance events.

According to Gordon van Welie, President and CEO of ISO-NE:

> We currently have a precarious operating situation in the winter time and we're worried about it becoming unsustainable beyond 2019… The reality is that we're really operating with a very slim operating margin during the winter time that may not cover these large contingencies that worry us.[316]

[kkk] These events included both situations in which natural gas power plants were unable to draw fuel from pipelines, as well as ones in which sufficient fuel was available but unit outages and/or start times inhibited operation.

Both programs remain in their infancy: ISO-NE's takes effect in 2018, and PJM's has only been active since 2016 (with a gradual phase-in through the 2019/2020 delivery year). In the interim, ISO-NE instituted a stopgap measure called the Winter Reliability Program, which compensates some dual-fuel generators for procuring onsite fuel.[317] Outside of these regions, onsite fuel is not compensated or, in the case of VIEU, is incorporated into integrated resource planning (IRP) efforts. Other aspects of fuel assurance include having dual fuel capabilities and having low exposure to supply chain interruptions (including adequate, reliable infrastructure and sufficient contractual arrangements for fuel delivery).

Natural Gas

NERC refers to the "single point of disruption risk" as the increasing risk of fuel disruption that threatens generator availability. In a letter to Secretary Perry, NERC CEO Gerry Cauley observed that:

> Growing reliance on natural gas continues to raise reliability concerns regarding the ability of both gas and electric infrastructures to maintain the BPS reliability at acceptable levels. Many efforts have focused on the gas-electric interface and yet, insufficient progress has been made reconciling the planning approaches and operating practices (scheduling situation awareness, information sharing) between these two inter-linked sectors. Planning approaches, operational coordination, and regulatory partnerships are needed to assure fuel deliverability, availability, security (physical and cyber), and resilience to potential disruptions. Unfortunately, an approach not obvious in electricity markets today.[318]

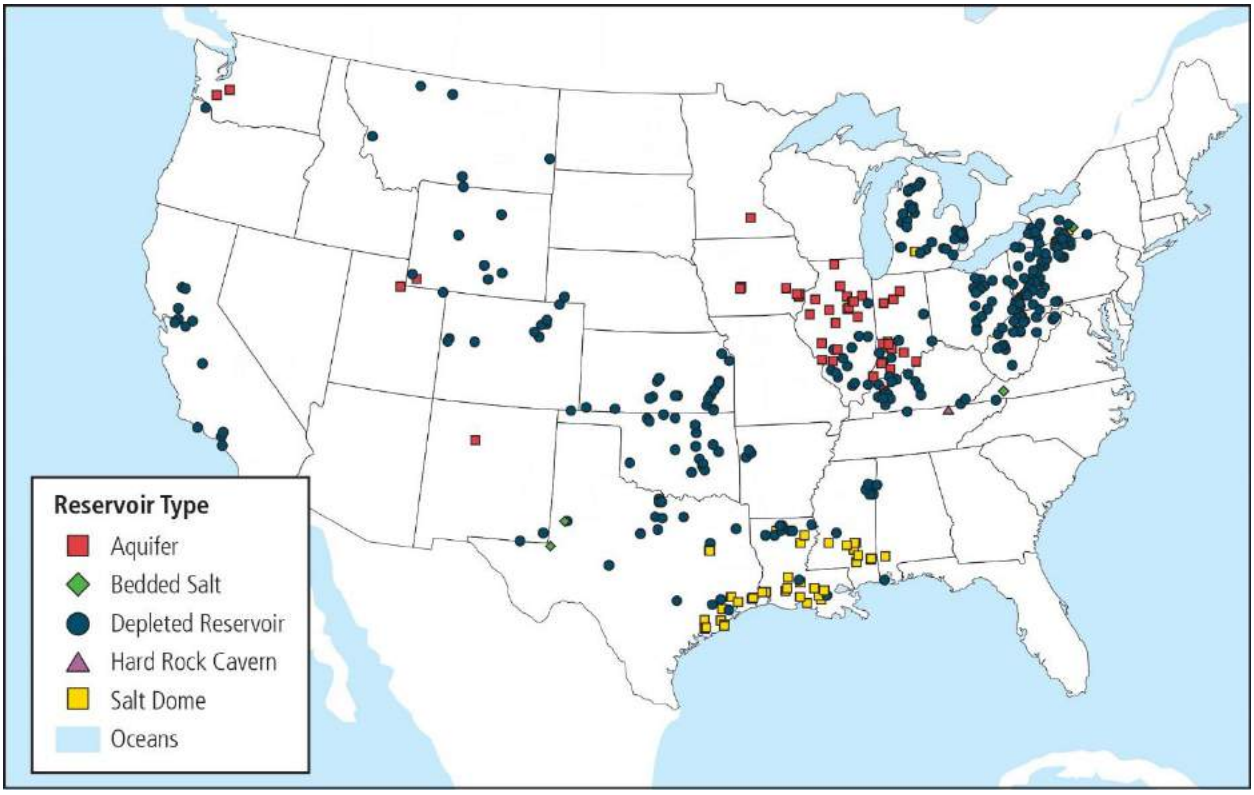
Natural gas-fired generators have been described as relying on "just-in-time" fuel delivery.[319] NERC, FERC, and several of the ISOs and RTOs have studied the gas-electric interactions and interdependence, which are most severe in the areas where natural gas generation is growing most quickly, but natural gas pipeline infrastructure is more constrained—particularly New England and California. NERC has concluded that:

> […] areas with a growing reliance on natural gas-fired generation are increasingly vulnerable to issues related to gas supply unavailability. Common-mode, single contingency-type disruptions to fuel supply and deliverability in areas with a high penetration of natural gas-fired generation are reducing resource adequacy and potentially introducing localized risks to reliability. Not only can impacts to BPS reliability occur during the gas-load peaking winter season, but they can also manifest during the summer season when electric demand is high and natural gas facilities are out of service, which can lower the operational capacity and flow of the pipeline system.[320]

NERC recommends a number of planning and operational changes to address this challenge, including risk-based approaches to study the potential regional reliability implications of greater natural gas dependence; the potential for wide-spread, common-mode failure events such as interstate gas pipeline or supply source losses; regional mitigation strategies; better information-sharing and coordination between electric generators, gas suppliers, and pipeline operators; and ensuring the availability of more flexible resources for use to mitigate the added uncertainties associated with natural gas fuel risks.[321]

Natural gas storage is a way to reduce the just-in-time delivery problem. Natural gas is stored in depleted natural gas and oil fields, depleted natural aquifers, and salt caverns. Figure 4.18 shows natural gas storage facilities across the Nation. The ideal storage facilities are near major gas consumption centers, where storage can supplement gas pipelines to meet high demand levels and fill in deliveries in the event of any delivery disruptions.

Figure 4.18. Natural Gas Storage Facilities[322]



The United States has over 400 natural gas storage facilities; the majority are depleted natural gas fields used for storage, with salt domes concentrated in the Southeast and aquifer storage concentrated in Illinois and Indiana.

Data presented at a recent testimony before FERC offers an interesting perspective on areas that depend on just-in-time energy. The data in Table 4-3 show a dozen states that depend on high levels of just-in-time imports, whether those imports are natural gas for in-area generation or transmission-enabled electricity imports. These areas may need greater planning and resilience measures to ensure fuel security, which may include some availability of petroleum-based fuels for units that can use them when natural gas may be difficult or expensive to source.

Table 4-3. Dependence on Imported Just-in-Time Energy for Electricity[323]

Risk Rank	State	Electricity Consumed in 2015 (GW Hour)	Net Electricity Imports (Exports)	Electricity Generation Using Imported Natural Gas	Total Imported Energy for Electricity
1	Washington DC	12,099	100%	0%	100%
2	Rhode Island	8,200	15%	80%	96%
3	Delaware	13,016	40%	51%	91%
4	Massachusetts	59,367	46%	35%	81%
5	Nevada	38,479	-1%	75%	74%
6	California	289,703	32%	36%	68%
7	Florida	256,344	7%	61%	68%
8	Vermont	5,885	66%	0%	66%
9	New Jersey	81,931	9%	45%	54%
10	Maryland	66,596	45%	7%	52%
11	Virginia	122,050	31%	20%	51%
12	New York	160,285	14%	35%	49%

The leaks discovered at California's Aliso Canyon natural gas storage facility in October 2015 California illustrate another natural gas common failure mode problem, according to analysis completed by PJM:

> Analysis performed after the leak identified 17 nearby electric generators with a combined output of over 9,800 MW that relied on Aliso Canyon for fuel supply. Some of these generators are required for local reliability; however, without supply from Aliso Canyon, low pressure in gas pipelines could stop the flow of gas to the generators, leaving them unable to operate.[324] The loss of Aliso Canyon gas storage field highlights the risk to the power grid from failures in the pipeline infrastructure. Electric market and regulatory changes in California resulting from this event include: expedited procurement of electric storage resources, enhanced gas-electric coordination, expanded demand response program and a constraint in the electric market that reflects gas limitations.[325]

After the 2014 Polar Vortex, when many gas-fired power plants were forced off-line due to natural gas production and delivery problems, inadequate gas supply contracts, and spiked natural gas prices, NERC recommended the following:

> Examine and review the natural gas supply issues encountered during the event. Industry should also work with gas suppliers, markets, and regulators to quickly identify issues with natural gas supply and transportation so that appropriate actions can be developed and implemented to allow generators to be able to secure firm supply and transportation at a reasonable rate.[326]

FERC has since promulgated orders to improve coordination between natural gas and power industry operations. While various electric and gas industry groups, including NERC, have had and continue coordination efforts, a significant amount of coordination remains unresolved.

Nuclear

As NERC noted, low exposure to fuel supply issues is one of the fundamental necessities of a reliable BPS. Still, fuel availability does not always guarantee dependable performance, particularly during extreme weather events. In 2010, the Browns Ferry nuclear plant in Alabama was throttled back to 50 percent of its maximum output because the plant was unable to draw and return enough water (due to environmental regulations) to cool all three of its reactors.[327]

Nuclear generators have onsite fuel storage due to their 18-month or 24-month refueling cycles.[328] During the Polar Vortex, some coal and nuclear plants had fuel onsite but failed to perform nonetheless. However, overall nuclear generators performed extremely well during the Polar Vortex, with an average capacity factor of 95 percent.[329]

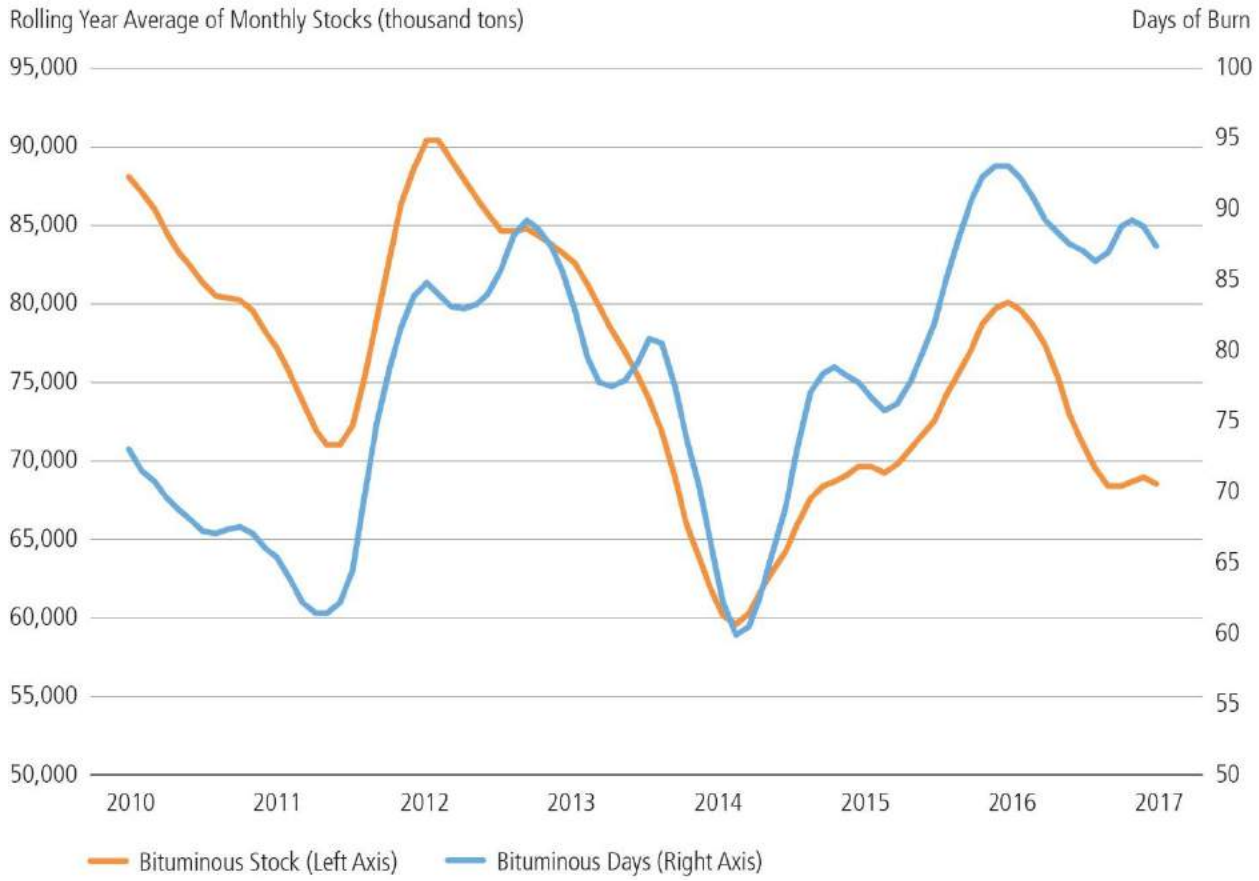
Nuclear power plants tend to have a very high number of "days of burn" onsite relative to coal, as their refueling occurs in 18-month or 24-month cycles. During each refueling, about one-third of the core is replaced with new fuel. The new fuel arrives onsite between nine and five weeks prior to the planned refueling. However, even if there is a delay in the arrival of new fuel, the reactor could continue to operate for an additional three months before reaching 70 percent capacity and two more months beyond that (for a total of five months) before decreasing to 50 percent capacity. The fuel that is replaced during each refueling has typically been used in the reactor for four-and-a-half to six years before it is removed. Planned refueling outages are typically scheduled for the spring and fall and average 35 days.[330]

Coal

A limited number of coal plants, including all plants that use lignite coal, are "mine-mouth" facilities that rely on dedicated, nearby coal mines. Otherwise, coal plants rely on rail, barge, or truck delivery of coal, and they maintain onsite coal stockpiles to accommodate both normal variance in deliveries and the possibility of a major supply disruption. Coal stockpiles have recently been slightly smaller than historical averages, while days of burn have increased slightly relative to historic averages from the 70–80-day range to the 85–100-day range (see Figure 4.19). [lll] [331]

[lll] At an individual plant, stockpiles can be viewed in terms of days of burn. The days-of-burn calculation considers both the current stockpile level at a plant and its estimated consumption (burn) rates in coming months to approximate how many days the plant could run at historical levels before depleting its existing stockpile.

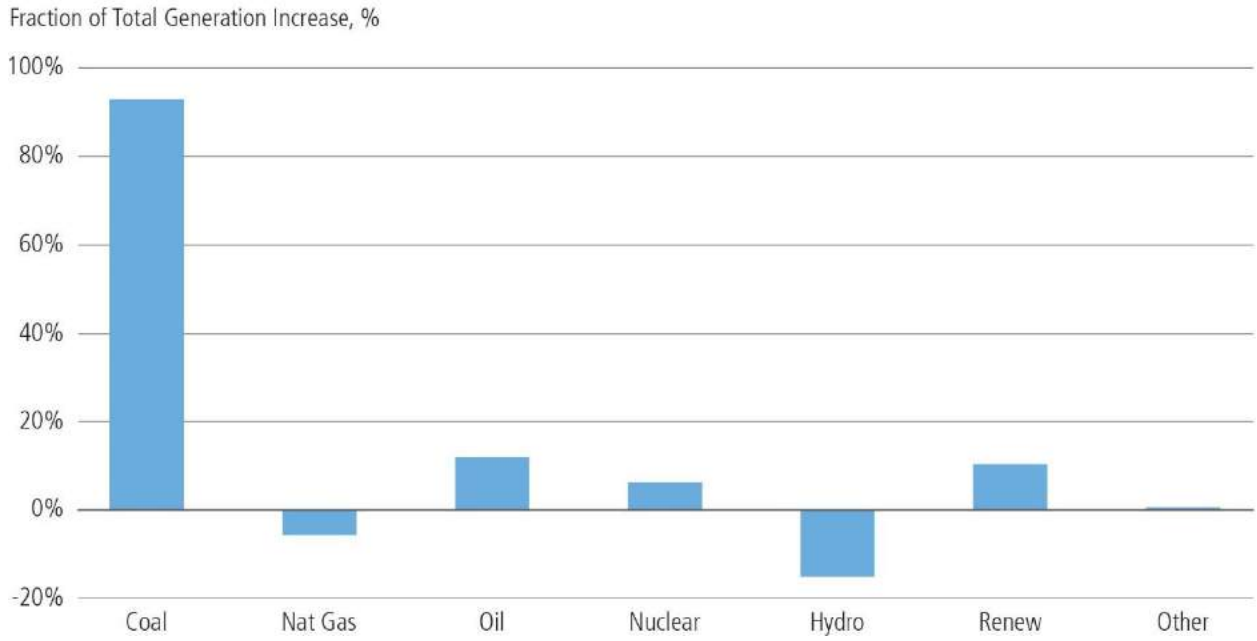
Figure 4.19. Coal Stocks and Days of Burn, January 2010–May 2017[332]



While bituminous coal stockpiles in tons have been slightly lower than historic averages in recent months, these stocks are expected to last relatively longer than historic average (measured in days of burn) due to lower capacity factors and expected lower fuel consumption in coal plants. Subbituminous coal stocks (not pictured) have increased in recent months relative to historic averages both in terms of tons and days of burn.

For the winter of 2014, compared to 2013, coal-fueled generation provided 92 percent of increased generation, as shown in Figure 4.20. Although electricity demand was greater in 2014, natural gas generation decreased because natural gas was diverted to fuel residential heating needs and gas prices rose to greater than three times those of coal.

Figure 4.20. Electricity Generation Changes from 2013 to 2014 by Fuel Type



Competition for natural gas between residential heating and power production caused a rise in natural gas prices in the early months of 2014. The high gas prices coupled with onsite coal storage led to a sharp increase in coal electricity production in those months compared to the winter of 2013.

Coal plants can also experience delivery interruptions. In 2013, there were 166 power plants (172,000 MW of generating capacity) across the United States that used subbituminous coal from the Powder River Basin. During the winter of 2013–2014, BNSF Railway rationed and limited coal deliveries to many of these generators due to construction and other disruptions. Stockpiles fell from 25 percent to 40 percent below normal levels at coal plants across the Midwest, Central, and Texas regions; many plants feared that they might not be able to rebuild their inventories in time to meet winter electric demands.[333]

4.3 High-Risk Events and System Resilience

The April 14 memo asks whether wholesale energy and capacity markets are adequately compensating attributes that strengthen grid resilience and, if not, the extent to which not compensating resilience attributes could affect grid reliability and resilience in the future.

A resilience approach recognizes that while not all risks can be avoided, many risks can be managed to mitigate damage and expedite recovery. Some options to improve grid resilience may be risk-specific (e.g., to protect against flooding) or component-specific (to protect a transformer), while others are "threat-agnostic, providing system-wide resilience to a broad range of threats including those that cannot be anticipated" according to the Grid Modernization Lab Consortium (GMLC).[334] As the fuel mix evolves and as threats change, there will be more ways that elements and regions of the BPS can fail. Causes of failure can include extreme weather events and cyber or physical attacks on grid infrastructure. [335] [336]

Extreme Weather Events

In January and February 2014, the Nation was swept by the Polar Vortex as a band of very cold weather spread across much of the eastern United States, creating record-high winter peak electric demand for heating and equally high demand for natural gas for residential heating. While the Polar Vortex tested the integrity of electricity supply, grid operators generally met demand, even under these severe conditions.

However, electricity and gas prices surged for many consumers as energy supplies were stressed. The extremely cold weather caused a variety of power system performance problems, including the loss of 35,000 MW of generation capacity across a wide stretch of the Nation, with 55 percent of the affected generation from natural gas plants, 26 percent coal plants and five percent nuclear.[337] In PJM, one of the regions most affected by the event, 22 percent of generating capacity was in forced outage.[338]

Many natural gas-fired generators had their fuel supplies curtailed because they were buying gas on non-firm, interruptible contracts, or because demand was so high that pipelines implemented delivery restrictions to power plants located near major metropolitan areas. In the Northeast, after several days of extremely cold weather, some generators experienced fuel-gelling, where the natural gas froze in the fuel injectors and was unable to feed into the turbines.[339] In Texas, a major source for natural gas production and a transport hub, several gas field production facilities froze up, as did some gas compressor stations along pipelines—shutting down gas feeds into and through pipelines that were to be shipped into New Mexico and elsewhere. This caused fuel shortages to the power plants served by those pipelines.[340] Limited supplies led to natural gas price spikes across much of the country; in some areas, gas to produce electricity was more expensive than liquid fuel, even though the price of oil for generation rose to over $400 per barrel. [341]

Many coal plants could not operate due to conveyor belts and coal piles freezing[342], which—coupled with outages across other fuels and high electricity demand—led operators to call on older plants nearing the end of their useful lives. American Electric Power reported that it deployed 89 percent of its coal units scheduled for retirement in 2014 to meet demand during the Polar Vortex, and Southern Company reported using 75 percent of its coal units scheduled for closure.[343] Using these retiring units enabled utilities to meet customer demand during a period when already limited natural gas resources were diverted from electricity production to meet residential heating needs.[344] [345] Once retired, however, these units will not be available for the next unseasonably cold winter.

In October 2012, Superstorm Sandy caused large-scale flooding and wind damage in the Mid-Atlantic and Northeast, as well as blizzard conditions in the central and southern Appalachians. Three nuclear reactors totaling 2,845 MW of capacity were shut down, and five operated at reduced levels due to disruptions in transmission infrastructure, reduced demand from distribution outages, and precautionary measures to protect equipment.[346] The storm impacts significantly disrupted East Coast refining activity. Spectra Energy lost two natural gas compressor stations on its Texas Eastern Transmission pipeline in northern New Jersey due to the loss of commercial power and the failure of backup generation to operate as intended, which affected gas supply to upstream gas-fired power plants. New Jersey Natural Gas shut down part of its natural gas infrastructure serving Ocean and Monmouth counties, including Long Beach Island and the barrier islands from Bay Head to Seaside Park, with subsequent distribution line damages.[347] Sandy also damaged solar PV installations in New Jersey, with storm surges causing $3 million of damage to ground-mounted PV systems and wind and lightning damage to rooftop PV systems.[348]

4.4 Enhancing Reliability and Resilience

Recently, based on extensive information about the operational profiles of PJM resources, PJM assessed the capability of each generator type to provide different ERS.[mmm] PJM then built a series of hypothetical resource portfolios using different mixes of generation types to determine how well each portfolio performed at delivering sufficient reliability. PJM also considered the risk that each portfolio would fail to meet resource adequacy needs and thus cause reliability problems. After simulating many combinations and portfolios, the following conclusions were reached:

- The expected near-term resource portfolio is among the highest-performing portfolios and is well equipped to provide the generator reliability attributes.
- As the potential future resource mix moves in the direction of less coal and nuclear generation, generator reliability attributes of frequency response, reactive capability and fuel assurance decrease, but flexibility and ramping attributes increase.
- A marked decrease in operational reliability was observed for portfolios with significantly increased amounts of wind and solar capacity (compared to the expected near-term resource portfolio), suggesting de facto performance-based upper bounds on the percent of system capacity from these resource types. Additionally, most portfolios with solar unforced capacity shares of 20 percent or greater were classified infeasible because they resulted in LOLE criterion violations at night. Nevertheless, PJM could maintain reliability with unprecedented levels of wind and solar resources, assuming a portfolio of other resources that provides a sufficient amount of reliability services.
- Portfolios composed of up to 86 percent natural gas-fired resources maintained operational reliability. Thus, this analysis did not identify an upper bound for natural gas. However, additional risks, such as gas deliverability during polar vortex-type conditions and uncertainties associated with economics and public policy, were not fully captured in this analysis. Risks with respect to natural gas may lie not in capability to provide the generator reliability attributes but rather in these other uncertainties.
- More diverse portfolios are not necessarily more reliable; rather, there are resource blends between the most diverse and least diverse portfolios which provide the most generator reliability attributes.[349] [original footnotes omitted]

Significantly, when PJM tested the most desirable portfolios (in terms of reliability) against a polar vortex event, only a third of those were resilient:

> Only 34 of the 98 portfolios which were classified as desirable were resilient when subjected to a polar vortex event. This sensitivity specifically captured the increased risk of natural gas delivery under extremely cold and high load conditions. The polar vortex sensitivity highlights the importance of resilience, which is not captured by the generator reliability attributes that were considered in this study.[350]

DOE, NERC, and industry stakeholders prepare for a variety of potential threats, including high-impact, low-frequency events, to improve resilience and recovery. Planning, practice, and coordination on an all-hazards basis are as important for improving resilience as having a mix of resources and fuels available when a major grid disturbance occurs. A diverse resource portfolio could complement wholesale market products that recognize and compensate providers for the value of ERS on a technology-neutral basis.

[mmm] The PJM study assumed firm gas supply contracts for natural gas-fired generators.

DOE's Grid Modernization Initiative (GMI) works to better understand what resilience means for the power system and how to measure and achieve it.

Transmission planning also supports grid reliability and resilience through interconnecting diverse resources, and it occurs at a variety of levels—ranging from individual utility system studies to regional and interconnection-wide studies. In 2009, DOE issued a series of grants to support interconnection-wide transmission planning. In 2011, FERC issued Order No. 1000, which (among other requirements) mandates regional transmission planning and interregional coordination. As noted in a recent study for the WIRES group:

> The analytical approaches applied to interregional [transmission] planning should look beyond "base cases" or "business-as-usual cases" and explicitly consider a broader range of plausible market conditions, system contingencies, and public policy environments to capture the short- and long-term flexibility benefits and insurance value that a more robust interregional transmission infrastructure can offer in terms of shielding customers from high-cost outcomes.
>
> … we recommend that such futures be evaluated to identify transmission projects that address current needs but also provide the insurance and flexibility value to mitigate high-cost outcomes across a range of uncertain but not implausible futures.[351]

Given the many problems that can affect different generation and fuel types, system-wide reliability and resilience can be supported by a diverse portfolio of generation resources that limit over-dependence on any single fuel or technology type, plus demand-side resources that reduce overall demand and better protect customers in the event of a widespread extreme event.

4.5 Reliability and Resilience Looking Forward

Although the BPS is performing reliably today with the current mix of resources, technologies, and loads, the entire system remains volatile. Low customer demands and a flatter supply curve mean that many generators face continuing economic stress, retirements may continue, and utility-scale and customer-side VRE additions (enabled by subsidies and mandates) will continue. These factors and the uncertainty about future conditions are making it harder for grid planners and operators to maintain today's level of reliability.

Any successful strategy to address BPS reliability and resilience going forward should include developing portfolios of resources that deliver both resource adequacy and ERS to advance reliable grid operations. Resource portfolios could be complemented with wholesale market and product designs that recognize and complement resource diversity by compensating providers for the value of ERS on a technology-neutral basis. More work is needed to define, quantify, and value resilience; Sandia National Laboratories has made efforts to do so, as shown in Figure 4.21.

Figure 4.21. Sandia National Laboratories' Resilience Analysis Process[352]

5 Wholesale Electricity Markets

The wholesale electricity market issues outlined in the April 14 memo are central to the future of U.S. electricity markets and policy. At the same time, they are the subject of intense debate among stakeholders with differing regional and economic interests. Noting the wide range of opinion on these issues, DOE staff offer three general findings:

1) Changing circumstances are challenging centrally-organized wholesale markets. Flat demand growth, Federal and state policy interventions, and the massive economic shift in the relative economics of natural gas compared to other fuels are creating stresses on wholesale electricity markets. The centrally-organized markets are successfully achieving reliable and economically efficient delivery of wholesale electricity in their short-term operations, but the changing circumstances portend potential long-term problems for centrally-organized and, to a lesser extent, bilateral markets.
2) New technologies with very low marginal costs, i.e. VRE, reduce wholesale prices, independent of—and in addition to—the effects of low natural gas prices. To the extent that additional development of such resources is driven by subsidies and mandates, their price suppressive effect might place undue economic pressure on revenues for traditional baseload (as well as non-baseload) resources and could require changes in market design.[353 354 355]
3) Markets need further work to address grid resilience. Market mechanisms are designed to incentivize individual resources rather than develop balanced portfolios. System operators are working toward recognizing, defining, and compensating for reliability- and resilience-enhancing resource attributes (on both the supply and demand side), but more work must be done.

U.S. market structures vary widely, but despite substantial differences between markets, some patterns emerge and are worth addressing in response to the April 14 memo.

5.1 Evolution of U.S. Wholesale Electricity Markets

Until the 1970s, investor-owned electric utilities were vertically integrated (i.e., provided generation, transmission, and distribution of electricity to their customers at regulated rates and with administratively determined profits). This concept was loosely referred to as the “regulatory

compact."[nnn] Interspersed with VIEUs were—and still are—over 3,200 cooperatively owned electric utilities.[ooo] [356]

In the 1920s, policymakers accepted the idea that non-utility companies might be able to generate electricity at equal or lower cost than VIEUs, to the benefit of electricity consumers.[357] In 1978, Congress passed the Public Utility Regulatory Policies Act (PURPA), which introduced competition to the VIEU model and set the stage for later regulatory reform of the electricity industry.[358] At the time, PURPA was largely an effort to curb the electricity industry's reliance on high-cost natural gas and oil.[ppp] PURPA provided for "increased conservation of electric energy, increased efficiency in the use of facilities and resources by electric utilities, and equitable retail rates for electric consumers." [359] It also made developing new generation resources easier—specifically renewable energy and cogeneration facilities.[360]

The Energy Policy Act of 1992 allowed FERC to approve "exempt wholesale generators," using any fuel and any generation technology, to go into the generation business and sell electricity at competitive prices. The act also authorized FERC to order transmission owners to provide transmission service.[361] Also in 1992, Congress enacted the PTC to incentivize VRE energy production, which Congress has extended and modified several times since.[362]

In 1996, FERC required transmission owners under its jurisdiction to provide open-access transmission to the interstate transmission grid through its landmark Order No. 888. Open access means charging all similarly situated parties the same rate (including, if applicable, what the utility would charge itself to use its transmission facilities) and providing service to all similarly situated parties under the same terms and conditions.[363] This action by FERC greatly assisted the development of competition among wholesale power producers because it meant that utilities would find it difficult to limit access to their transmission facilities as a means of protecting their generation assets from competitors. FERC Order No. 2000 (issued in December 1999) promoted voluntary participation in RTO/ISOs by further clarifying both necessary characteristics of RTO/ISOs and benefits of such participation.[364]

Between 1998 and 2006, 23 states made changes to require their VIEUs to divest some or all of their generating assets and thus allow competition.[365] Divestiture was pursued most aggressively by the states with high retail electricity prices (most of New England, New York, the Mid-Atlantic states, and

---

[nnn] "The 'state regulatory compact' evolved as a concept 'to characterize the set of mutual rights, obligations, and benefits that exist between the utility and society.' It is not a binding agreement. Under this 'compact,' a utility typically is given exclusive access to a designated—or franchised—service territory and can recover its prudent costs (as determined by the regulator) plus a reasonable rate of return on its investments. In return, the utility must fulfill its service obligation of providing universal access service within its territory. https://www.energy.gov/sites/prod/files/2017/02/f34/Appendix--Electricity%20System%20Overview.pdf

[ooo] Most public power utilities are distribution-only; however, some are vertically integrated. Distribution-only cooperatives typically purchase all or some of their electricity at the wholesale level from generation and transmission cooperative utilities.

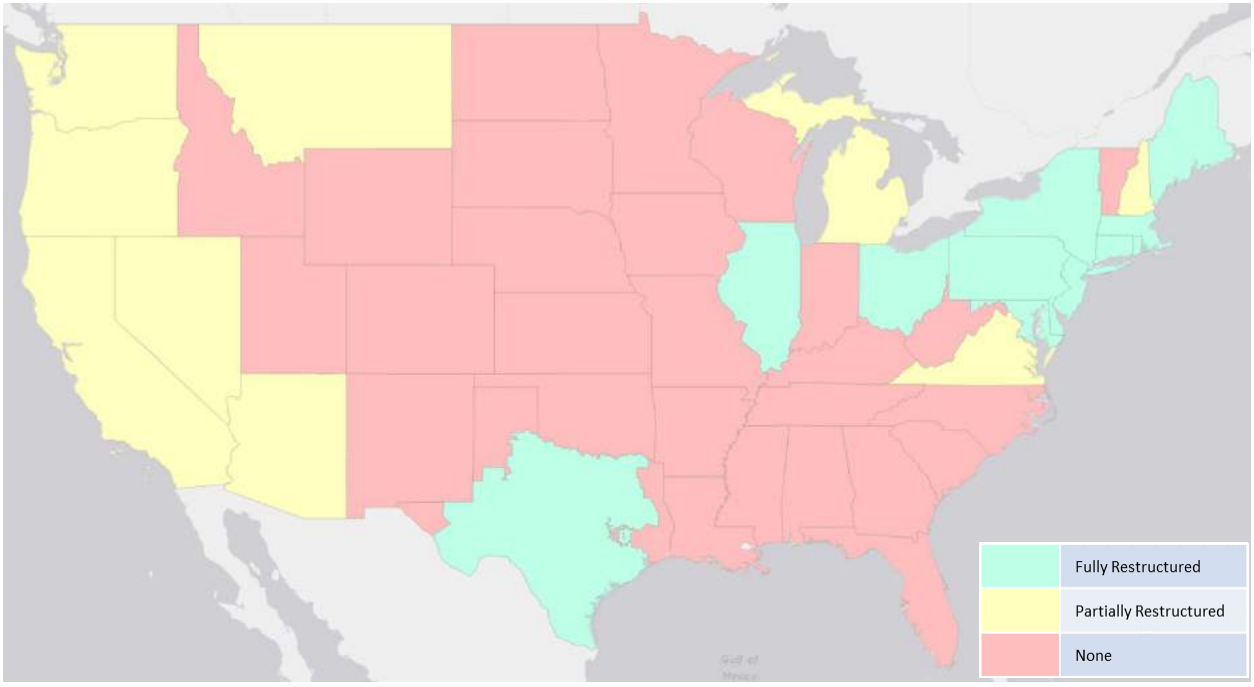
[ppp] Also in 1978, the Power Plant and Industrial Fuel Use Act prohibited "(1) the use of natural gas or petroleum as a[n] energy source in any new electric power plant; and (2) construction of any new electric power plant without the capability to use coal or any alternate fuel as a primary energy source." https://www.congress.gov/bill/95th-congress/house-bill/5146

The Fuel Use Act was mostly repealed in 1987, which "set the stage for a dramatic increase in the use of natural gas for electric generation and industrial processing." https://www.eia.gov/oil_gas/natural_gas/analysis_publications/ngmajorleg/repeal.html

California) with the hope that competition would bring lower retail consumer prices.[qqq] [366] Generating units that had been operating under cost-of-service regulation were sold to merchant plant owners or transferred to unregulated, investor-owned utility affiliates.

This wave of restructuring did not sweep the entire Nation. In large areas—particularly the Southeast and the West, apart from the expanding Energy Imbalance Market—the wholesale electricity industry is still vertically integrated. In these areas, the wholesale market consists of bilateral transactions. Because restructuring did not take hold in all states, a range of organizational structures exist at the wholesale level in the United States today, as shown in Figure 5.1. States considered "Partially Restructured" below have divested some generation and/or allowed a portion of customers to choose their energy provider.

Figure 5.1. Utility Restructuring by State as of May 2017[367]



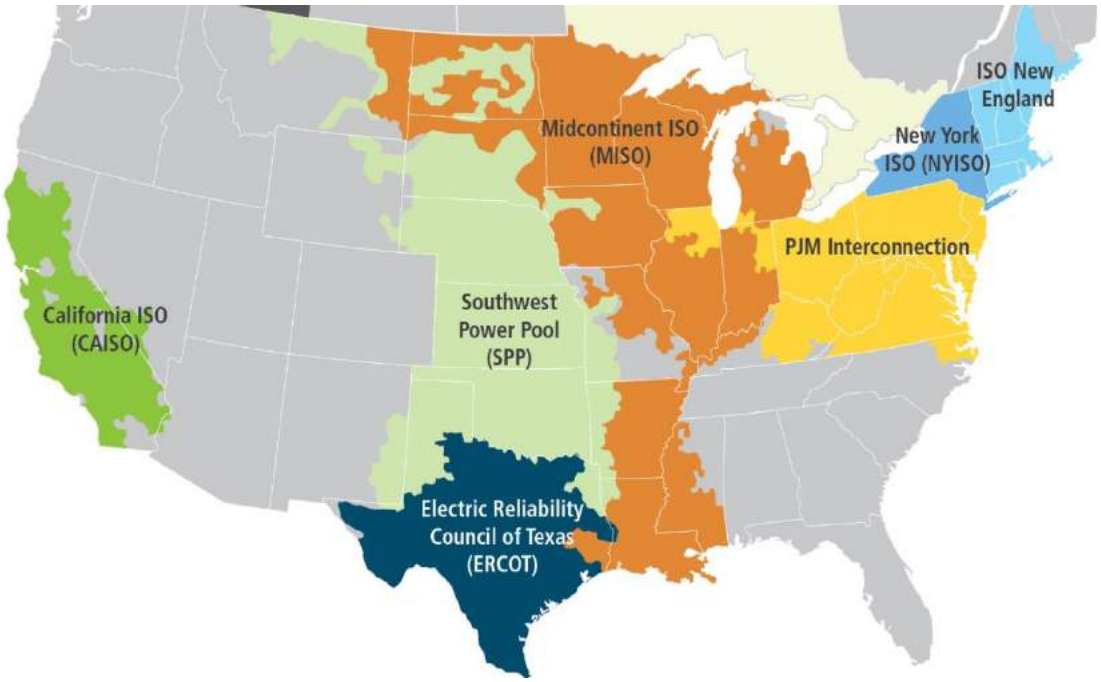
5.2 Wholesale Electricity Markets Today

Over the past two decades, a diverse set of wholesale electricity markets has evolved in different regions of the United States. These wholesale markets can be divided into two broad categories. For the purposes of this section, regions of the country that have not joined RTO/ISOs are called traditional

[qqq] Whether this objective has been achieved is mixed in the literature. Availability rates for generation have improved significantly and, as predicted, as competition incentivized operators to run their units as efficiently as possible. Dispatch over the much broader footprints of RTO/ISOs also increases efficiency and thus reduces costs. PJM notes (July 26, 2017 written statement before Subcommittee on Energy, U.S. House Committee on Energy and Commerce) "nearly $2 billion of annual savings to customers." On the other hand, Borenstein's 2015 review claims "the electricity rate changes since restructuring have been driven more by exogenous factors - such as generation technology advances and natural gas price fluctuations - than by the effects of restructuring." See two meta-studies: Severin Borenstein and James Bushnell, "The U.S. Electricity Industry after 20 Years of Restructuring," May 2015, https://ei.haas.berkeley.edu/research/papers/WP252.pdf and James Bushnell, Erin T. Mansur, and Kevin Novan, "Review of the Economics Literature on US Electricity Restructuring," April 2017, for DOE, unpublished.

bilateral markets, while those that have are called centrally-organized markets. These regions are shown in Figure 5.2, with RTO/ISOs labeled and colored, and bilateral markets depicted in gray.

Figure 5.2. The Seven RTOs or ISOs in the United States[rrr] [368]

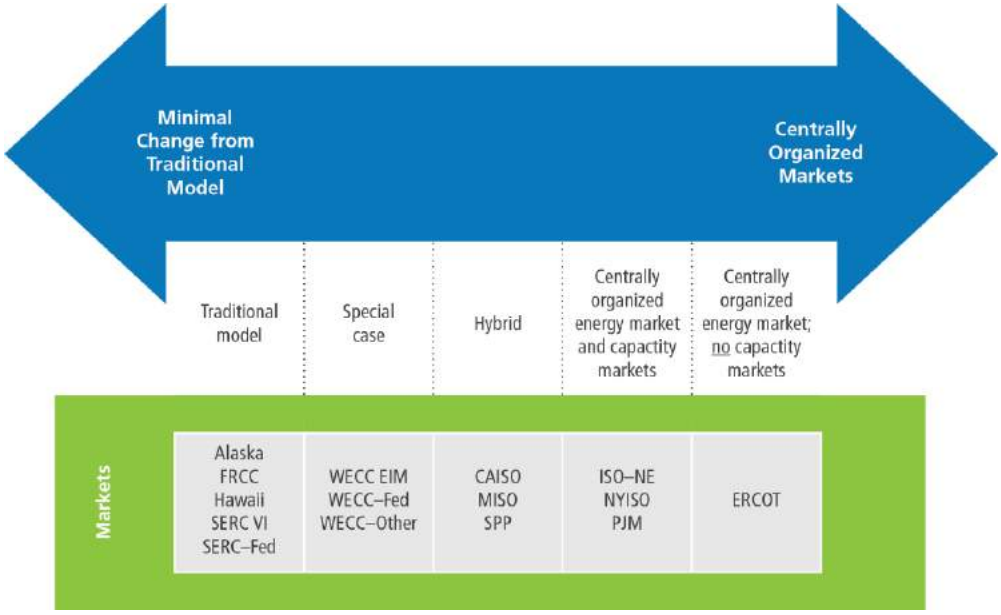


There are currently seven centrally-organized markets operating across the United States.

The diversity of approaches to market organization and resource adequacy can be visualized along a spectrum, as shown in Figure 5.3—from VIEUs with minimal market organization on one end, to fully restructured markets without formal resource adequacy requirements on the other. Between vertically integrated and energy-only regions, there are diverse approaches to allocating the financial risk of generation investment and the responsibility to provide resource adequacy.

[rrr] Map redrawn from FERC's December 2016 website.

Figure 5.3. States and Regions along the Spectrum from Traditional to Fully Restructured Electric Markets[369]



In the Southeast and West, bilateral markets are dominated by VIEUs that operate under a regulated cost-of-service model. States in these regions retain strong control over electric utility resource decisions and oversee resource adequacy, and they consider non-market factors in their oversight of utility decisions through a utility's IRP process. Once approved by state regulators, ratepayers guarantee the cost recovery of VIEU generation investments through retail rates (or merchant generators through long-term PPAs with utilities). Thus, the financial viability of these generators is not immediately exposed to the same price volatility that generators face in market-oriented regions. However, new resource decisions in VIEU regions are beginning to account for low natural gas prices, low load growth, and zero-marginal cost generation.[sss]

Public power and rural cooperative utilities also have a significant presence in some regions. Utility asset ownership models can vary from vertically integrated to distribution-only. Merchant generators also operate within these regions, but most electricity is produced and delivered by the integrated utilities, with minimal additional spot transactions.[370]

In centrally-organized markets, generators offer electricity bids on a day-ahead and real-time basis. The RTO/ISO then pools these bids into a single supply curve and calculates the clearing price that matches supply to demand, considering transmission limitations for the next interval. This calculation yields a set of market-clearing prices, one for each location and time horizon. Centrally-organized markets also compensate resources that provide certain ERS through ancillary service markets. Furthermore, in some cases, RTO/ISOs provide supplemental revenues to generators that are dispatched out-of-market, such as ones that are needed to ensure local reliability.

[sss] See, for example, 152 FERC ¶ 61,013 (Florida Power & Light Company) or Steve Wright, General Manager, Chelan County PUD, a vertically integrated utility in Washington, told DOE staff in a June 19, 2017, conversation that the relatively low wholesale prices traditionally seen in the Northwest due to an abundance of low-cost hydro are now further stressed by the export of surplus zero-marginal cost California rooftop solar, so much so that he is "finding it hard to even justify spending on energy efficiency in [his utility's] integrated resource plan."

RTOs/ISOs operate as a single balancing authority and achieve cost savings by procuring reserves and other ancillary services for the system. For example, MISO estimates that because it operates an ancillary service market across the entire region, spinning reserve requirements can be based upon the entire region's needs rather than the sum of individual balancing authorities' spinning reserve requirements. By operating the ancillary services market, MISO reduced its average spinning reserves requirement from 1,482 MW to 935 MW and saved almost $25 million per year for its members by freeing up generation from having to meet the reserve requirement.[371]

CAISO, MISO, and SPP retain aspects of the bilateral markets, particularly that states still oversee resource procurement and resource adequacy of their VIEUs, through the IRP process.[372] California, MISO and SPP, as well as traditional bilateral market states, incorporate considerations other than short-term economic efficiency into their resource choices, such as portfolio diversity, job retention or creation, environmental protection, and other factors.

5.2.1 Responsibility for Resource Adequacy and Capacity

Some states require utilities to build new or subsidize specific power plants outside the RTO/ISO resource adequacy processes. Other centrally-organized markets (namely PJM, ISO-NE, and NYISO) have implemented capacity markets as a mechanism to provide sufficient revenue for resources to ensure resource adequacy. In these markets, the system operator conducts an auction process, and wholesale customers procure resources (including generation, energy efficiency, DR, and transmission-enabled resource imports) to meet the electricity demands of their customers. These markets can be mandatory (PJM Interconnection and ISO New England); voluntary, where states can choose to operate under an IRP process and where load-serving entities can satisfy their requirements through a combination of the market and/or showing that they have rights to adequate capacity (MISO); or voluntarily backstopped by a mandatory process (NYISO). ERCOT does not have a formal resource adequacy requirement.

5.3 Challenges in Wholesale Electricity Markets

Centrally-organized markets are now 15–20 years old, and their original designs (even with continual and evolving updates) are showing signs of strain from the pace of change now underway in the electricity industry. Many of these changes were not foreseen during the restructuring and wholesale market designs of the 1990s–2000s. Flat demand growth, flattened supply curves, Federal and state policy interventions, and the massive economic shift in the relative economics of natural gas compared to other fuels are placing pressures on centrally-organized wholesale electricity markets, resulting in low average wholesale energy prices. These markets were designed when supply curves tilted sharply upward, demand grew over time, and capacity was not explicitly compensated to make up for insufficient revenues from an energy-only market. A 2014 FERC staff report notes:

> A failure to properly reflect in market prices the value of reliability to consumers and operator actions taken to ensure reliability can lead to inefficient prices in the energy and ancillary services markets leading to inefficient system utilization, and muted investment signals.[373]

The issue of revenue insufficiency and generator retirements in centrally-organized electricity markets is a complex topic, with causality difficult to assign beyond the individual asset/owner level.[ttt] Each plant has its own cost structure, and plant revenues can differ between neighboring nodes in a single market.

Traditional, bilateral-only wholesale markets are not immune to these issues either, but may not be seeing them yet at the same scale as the three eastern RTO/ISOs that have a predominance of merchant generation. An issue that is more prevalent in these regions than in regions with bilateral markets is the PURPA "must-purchase obligation" that still applies to those regions. After Congress amended PURPA in the Energy Policy Act of 2005, many utilities in regions with centrally-organized wholesale markets have sought and received from FERC orders terminating their obligations.[374]

By contrast, utilities in regions with traditional, bilateral-only wholesale markets remain subject to the PURPA requirement to buy power from Qualifying Facilities (QFs) under PPAs, with up to 20-year terms and at rates that the applicable state regulator has determined reflect the purchasing utility's avoided costs. In some instances, generation purchased from QFs has displaced utility-owned generation and thus reduced utility revenue. PURPA remains a subject of ongoing debate within the industry, as evidenced by a discussion during a FERC June 2016 Technical Conference.[375]

5.3.1 Revenue Insufficiency due to Market Structure: The Missing Money Problem

In the mid-2000s it became apparent that merchant generators were failing to recover sufficient revenues through the energy-only markets to cover both their variable and fixed costs. The issue subsequently became known as the "missing money problem."[uuu] In testimony before a 2014 FERC technical conference, David Patton, the independent market monitor for ERCOT, ISO-NE, MISO, and NYISO, described the issue as stemming from overly-stringent planning reserve requirements:

> With reasonable assumptions about capacity cost and energy prices, [the one-day-in-ten-years] reliability standard implies a value of lost load of $100,000 to $200,000 per MWh.
>
> Hence, without substantially inflated shortage prices, energy-only markets cannot provide enough revenue to satisfy planning reserve requirements. Additional revenue is needed to satisfy these requirements, which is the "missing money" problem addressed by the capacity markets.[376]

William Hogan of Harvard University noted in 2005 that the missing money problem can also be attributed to price caps:

> The missing money problem arises when occasional market price increases are limited by administrative actions such as price caps. By preventing prices from reaching high levels during times of relative scarcity, these administrative actions reduce the payments that could be applied towards the fixed operating costs of existing generation plants and the investment costs of new plants.[377]

To mitigate the missing money problem, centrally-organized markets have, to varying degrees, utilized shortage pricing and capacity markets.

[ttt] The market issues discussed in this section are most pertinent to a merchant generator operating within centrally-organized markets that are not subject to regulated rate recovery.

[uuu] The first use of this term is attributed to Roy Shanker in his 2003 testimony before FERC. William W. Hogan, Harvard University, "'Energy Only' Electricity Market Design for Resource Adequacy," September 23, 2005

Shortage Pricing

Shortage pricing, also referred to as scarcity pricing, seeks to ensure that energy market revenues reflect the value consumers place on reliability. It does this through administrative rules that raise prices above marginal costs during times of system stress. FERC has actively sought to improve the utilization of techniques like shortage pricing. In a 2014 analysis, FERC staff provided a useful overview of the rationale for shortage pricing:

> When the system operator is unable to meet system needs, it applies administrative pricing rules to ensure that costs, including the costs associated with the failure to meet minimum operating reserve requirements, are reflected in market prices. …Under such conditions, prices should rise, inducing performance of existing supply resources and encouraging load to reduce consumption so that the system operator would not need to administratively curtail load to maintain reliability. [378]

All of the Nation's RTO/ISOs currently employ shortage pricing to some degree; however, the designs are not uniform. FERC Order No. 831 raised energy offer caps in jurisdictional RTO/ISOs from $1,000 to $2,000/MWh.[379] Conditions required to trigger shortage pricing vary from year to year. This variance could present challenges to market participants who require a threshold level of certainty to make an investment decision. Remarks by market monitors David Patton and Joe Bowring critique the practice of relying solely on shortage pricing:

> [David Patton:] Shortage pricing is not like a capacity market where you're going to get a level of revenue that might fluctuate by 10 to 20 percent per year. With shortage pricing, you might get 10 years of revenue in one year and then the other nine years the generators are going to think they're going bankrupt.[380]
>
> [Joe Bowring]: What will happen if you go through eight years of very low revenues under scarcity pricing … and a significant number of units decide to retire because they can't see into the future? They don't know if [in] the ninth or 10th year there's going to be $20 billion. They retire if the revenues aren't adequate.[381]

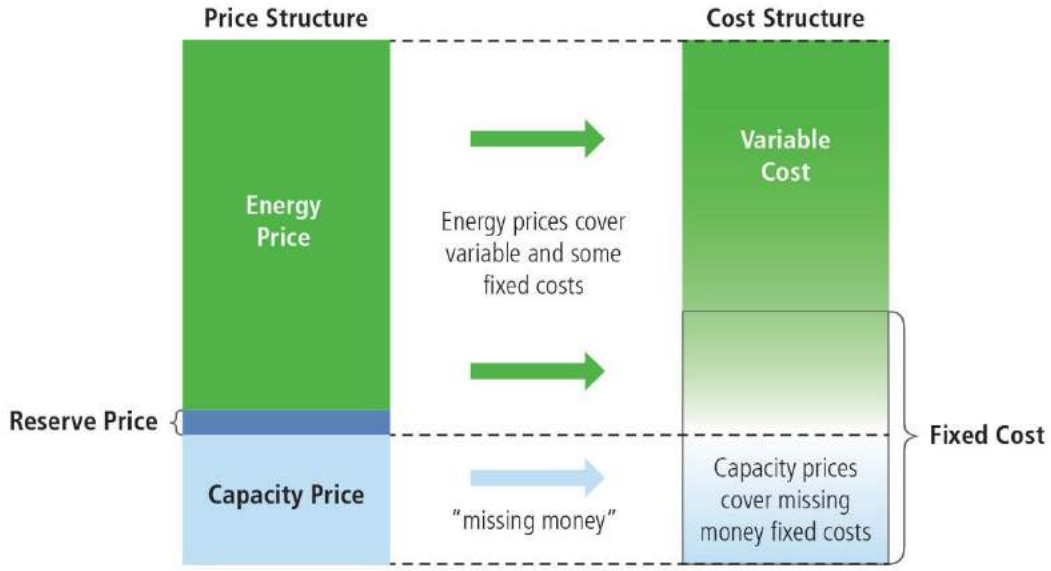
Capacity Markets

Four RTO/ISOs currently operate centralized capacity markets: ISO-NE, NYISO, and PJM hold mandatory auctions, while MISO's is voluntary. Capacity markets address the missing money problem by imposing resource adequacy requirements on load-serving entities (LSEs). Spees, Newell, and Pfeifenberger provide a useful overview of how this process works:

> A resource adequacy [requirement] requires LSEs to procure sufficient generation or demand-response capacity to serve their own customers' coincident peak load plus a mandatory planning reserve margin. If each LSE procures their required capacity, then the system as a whole will be able to meet its planning reserve margin requirement and target resource adequacy level. … [Capacity] has value as a stand-alone commodity, the demand for which is driven by LSEs needing to meet their resource adequacy requirement.[382]

According to the authors, capacity market revenues should in theory ameliorate the missing money problem by providing "the incremental payment needed to recover their investment costs in addition to the operating profits earned through energy and ancillary service sales."[383] Figure 5.4 provides a useful illustration of how capacity payments are intended to close the missing money gap.

Figure 5.4. How Market Prices Allow Resource Costs to be Recovered in a Centrally-organized Wholesale Market[384]



Revenues from energy sold in the wholesale market pay for a generators' variable costs and some portion of fixed costs (indicated by green arrows). The unrecovered portion of fixed cost (missing money) is recovered through capacity market revenues (indicated by blue arrow).

Some observers note that capacity markets may not provide sufficient revenues as originally intended. For example, the 2016 PJM Market Monitor's report finds PJM's markets can provide adequate revenue to support *some* existing capacity, but the outlook varies widely by technology, fuel choice, time interval, and location:

> Analysis of the total unit revenues of theoretical new entrant CTs and CCs for three representative locations shows that units that entered the PJM markets in 2007 have not covered their total costs, including the return on and of capital, on a cumulative basis through 2016. The analysis also shows that theoretical new entrant CTs and CCs that entered the PJM markets in 2012 have covered their total costs on a cumulative basis in the eastern PSEG [New Jersey] and BGE [Baltimore] zones but have not covered total costs in the western ComEd [Chicago] Zone. Energy market revenues were not sufficient to cover total costs in any scenario except the new entrant CC unit that went into operation in 2012 in BGE, which demonstrates the critical role of capacity market revenue in covering total costs.[vvv] [385]

5.3.2 Revenue Insufficiency due to External Forces

While RTO/ISOs have sought to address the missing money problem as previously defined, newer variants of it continue to permeate stakeholder discussions. Economist Severin Borenstein notes that the definition has expanded to include the supply curve impact of subsidies:

> Money has been going missing for many years, according to owners of power plants. They've used the term for more than a decade to refer to the fact that wholesale electricity markets have price caps (mostly between $1,000 and $10,000 per MWh) that constrain how

[vvv] As part of the review of market performance, the market monitor analyzed the net revenues earned by CTs, NGCCs, coal, diesel, nuclear, solar, and wind generating units.

> much sellers can make when supply is tight. Without that income, generators argue, it may not be profitable to build new capacity, or extend the life of existing capacity, that is needed to meet demand.
>
> More recently, the definition of missing money has been expanded to include the price impacts of subsidized or mandated renewables generation. In California, New York and many other states, wind and solar are pushing down wholesale prices and making continued operation of some nuclear and fossil fuel generation unprofitable. [386]

Shifts in the Generation Supply Curve

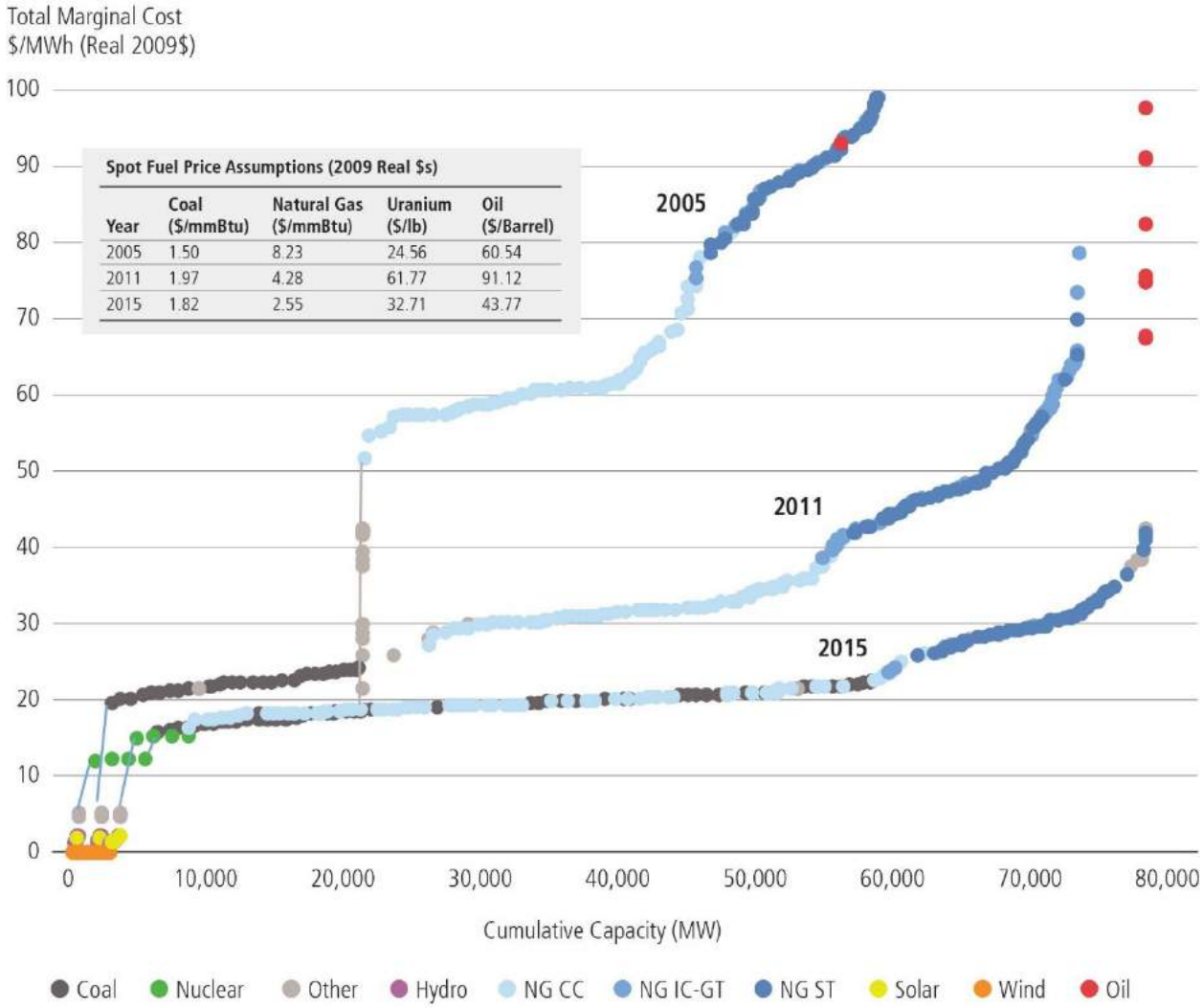
Changes in the Nation's generation mix have generally reduced revenues for incumbent baseload generators in wholesale markets, as highlighted in QER 1.2:

> [P]rice suppression is occurring in RTO/ISO wholesale markets, with noticeable amounts of wind and solar generation (and low-cost gas generation). While passing on savings to consumers is desirable, in some regions, these low prices have put pressure on baseload units, particularly zero-carbon emissions nuclear generation.[387]

Put more specifically, shifts in market supply curves have lowered the infra-marginal rents[www] earned by baseload generators. Crucially, this reduction has occurred because of changes along *both* axes of the supply curve. Along the horizontal (supply) axis, the entry of new resources has pushed the curve to the right, resulting in a lower clearing price at the same level of demand. Meanwhile, reductions in marginal fuel costs (vertical axis) have lowered the slope of the curve. The net effect of these changes—as illustrated by a simulated dispatch curve in ERCOT—is shown in Figure 5.5.

[www] Infra-marginal rents are the differences between the market-clearing price and the submitted bid of each generator. Generators that bid less than the market-clearing price receive a payment equal to this difference.

Figure 5.5. Simulated ERCOT Dispatch Curves[xxx]



Spot Fuel Price Assumptions (2009 Real $s)

Year	Coal ($/mmBtu)	Natural Gas ($/mmBtu)	Uranium ($/lb)	Oil ($/Barrel)
2005	1.50	8.23	24.56	60.54
2011	1.97	4.28	61.77	91.12
2015	1.82	2.55	32.71	43.77

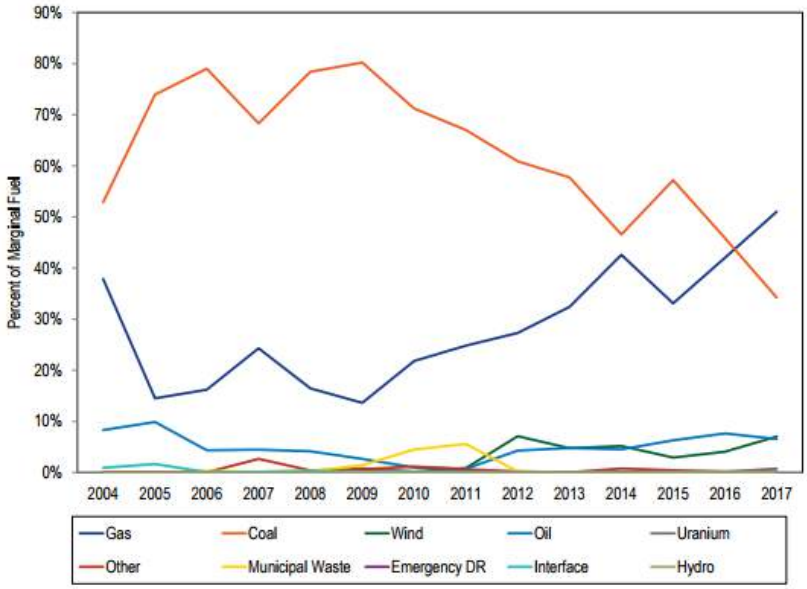
Changes in fuel costs and the supply mix have impacted market clearing prices, and thus lowered infra-marginal rents for incumbent generators. Reductions in natural gas prices have clearly flattened the curve, reducing revenues for generation resources. The entry of new, near-zero marginal cost resources has also pushed the overall curve to the right. The entry of wind and solar resources is visible in lower left.

Natural Gas and Incumbent Baseload

The frequency with which natural gas sets the price of electricity has increased in many of the Nation's markets. For example, 2017 could mark the first time in PJM's history that gas is marginal for more intervals than coal (see Figure 5.6). This transition means that infra-marginal rents that were previously based on the marginal cost of coal resources have been supplanted by the marginal cost of natural gas resources.

[xxx] EIA, analysis performed for DOE using EIA and ABB Ventyx software to show estimated plant-specific estimated production costs for July 15 of each year modeled, using then-current delivered energy prices (in 2009 $) within ERCOT and estimated, plant-specific heat rates to estimate plant-specific marginal costs of electricity production, June 2017

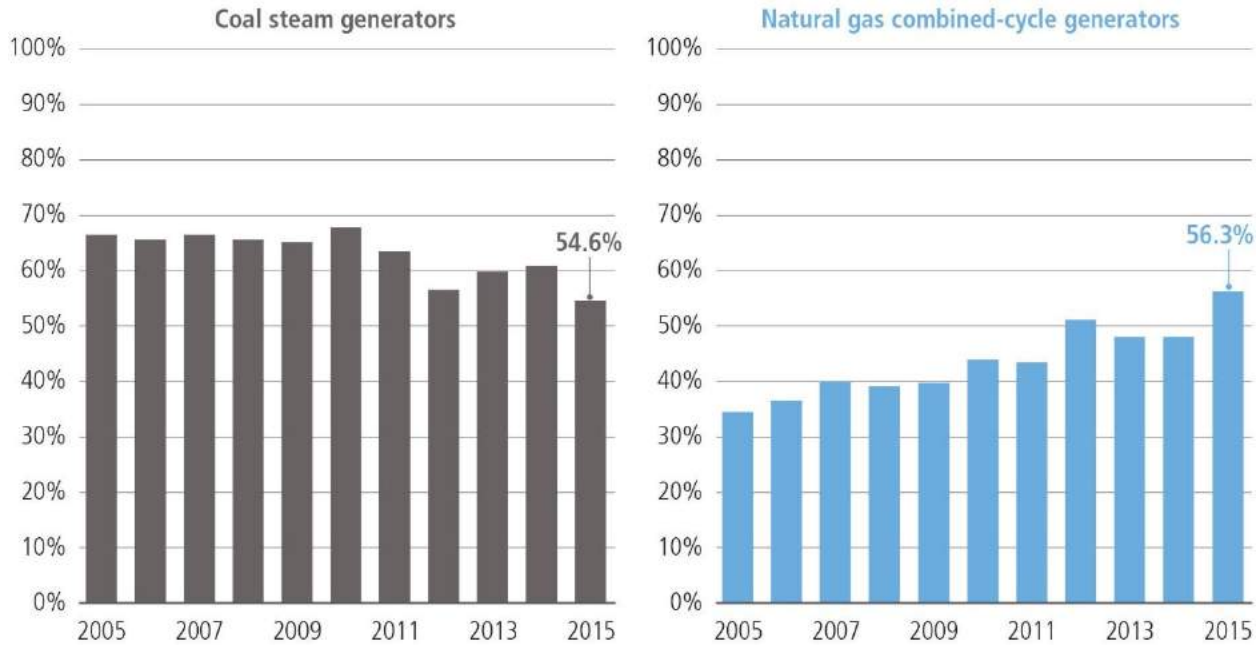
Figure 5.6. Type of Fuel Used in PJM (by Real-Time Marginal Units): 2004 through March 2017[388]



Natural gas is rising as the marginal electricity generation source in PJM.

The low price of natural gas has resulted in the competitive displacement of coal in many of the Nation's markets. This trend is visible in Figure 5.7 by comparing the 2005 curve to the 2015 version. The interspersed nature of the coal and gas generators in the 2015 curve reflects that the two now compete for the same runtime. While gas had been a mid-merit source in previous years, it has become more of a baseload resource in recent years. The phenomenon is visible on a national level by examining the capacity factors of the respective technologies.

Figure 5.7. Annual Average Capacity Factors of Coal and Natural Gas Generators



NGCC generators have seen a steady increase in fleet average capacity factor from 35% in 2005 to 56% in 2015; in that year, the NGCC fleet average eclipsed that of coal generators, which has declined from approximately 68% in 2010 to 55% in 2015.[389]

Negative Pricing

Negative pricing events in electricity markets reflect a complex set of economic, reliability, environmental, and safety variables. The interaction of these variables differs depending on the region, season, and time in question, but negative pricing often reflects some combination of excess generation (often exacerbated by must-run requirements), transmission constraints, and economic factors. According to analysis from LBNL, negative pricing events have historically been rare at many major pricing hubs (less than two percent of total hours in real-time markets in 2016), and have had almost no impact on annual average day-ahead or real-time wholesale electricity prices. However, more frequent negative pricing has been observed in CAISO, and in constrained hubs that feature a relatively large amount of VRE and/or nuclear generation.[390] In addition, PJM has observed that "prices go negative at nuclear units buses in approximately 2,176 hours – representing 14 percent of off-peak hours."[391]

The term economic factors in this case serves as a catchall for those negative pricing events that are not the direct result of must-run requirements. EIA provides examples of why generators might choose to run, even if it means accepting negative prices:

> Technical and economic factors may drive power plant operators to run generators even when power supply outstrips demand. For example:
>
> - For technical and cost recovery reasons, nuclear plant operators try to continuously operate at full power.
> - Eligible generators can take a 2.2¢/kWh or $22/MWh[yyy] production tax credit (PTC) on electricity sold. This means that some generators may be willing to sell their output for as low as -$22/MWh to continue producing power. Typically, wind generators are the largest such group in any region.
> - There are maintenance and fuel-cost penalties when operators shut down and start up large steam turbine (usually fossil-fueled) plants as demand varies over a day or a week. These costs may be avoided if the generator sells at a loss to attract a buyer when demand is low.[392]

As EIA notes, the PTC can create an incentive for wind generators to bid at negative prices. If other generators located at nodes in the areas affected by negative prices are unable or unwilling to reduce output, they will have to pay the negative price for their output. That scenario has unfolded on some buses in PJM, as outlined in comments to DOE from PJM staff:

> Tax and subsidy policies have had an impact on the economics of certain types of generation. The Renewable Energy Production Tax Credit and renewable energy mandates have had the most significant impact on nuclear generation. Specifically, the nuclear and wind generation are competing to clear in the market during off-peak hours when wind resources are the strongest and load is reduced. In those off-peak hours, the production tax credit has created an incentive for renewable resources to bid negative prices as they must run in order to receive their payment from the federal treasury. Since 2014, PJM has seen prices go negative at nuclear unit buses in approximately 2,176 hours—representing 14 percent of off-peak hours.[393] [footnotes omitted from original text]

[yyy] While the PTC value was $23/MWh in 2016, this figure was based upon EIA's interpretation of the PTC benefit at the time. https://www.eia.gov/todayinenergy/detail.php?id=8870

ERCOT's market monitor identified 130 negative-priced hours for the entire system in 2016, an increase from 50 hours in 2015.[394] Negative prices in ERCOT are now on the rise due to subsidized wind, as noted by William Hogan and Susan Pope in a recent study filed with the PUC of Texas by Calpine and NRG:

> Prior to the increase in wind and other intermittent capacity in the ISOs, negative prices sometimes occurred in the middle of the night, as load dropped and generators needed for operation the following day were pinned at their minimum loads. In contrast, the increasing incidence of negative prices in ERCOT is caused by the incentive of the owners of wind generation capacity receiving the PTC to continue to produce even when the locational price is negative.[395]

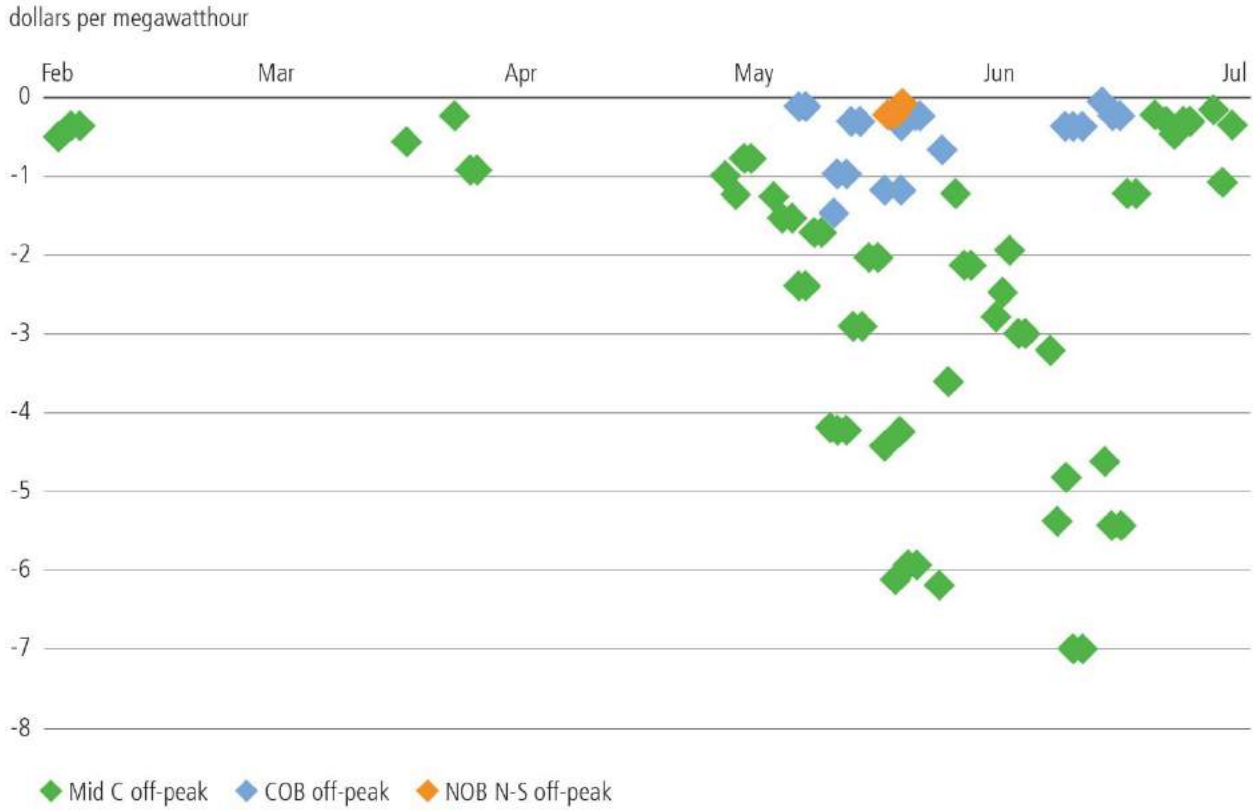
In addition to the PTC, VRE may also be incentivized to submit negative bids into markets by demand for RECs (to satisfy state environmental mandates and/or corporate sustainability goals).

Conventional generators also face economic factors that lead them to submit negative bids. Existing nuclear plants in the United States, as well as some fossil units, may bid in during these periods to avoid costly start-ups and shutdowns.[396] For example, steam turbine plants may choose not to cut back their production if they are not designed to cycle economically.

Operational attributes can also create or exacerbate negative prices. For example, hydroelectric plants are limited in their ability to curtail output because of environmental and safety reasons. Flood control and wildlife regulations are two important reasons this can take place. As this winter's record precipitation gave way to snowmelt this spring, CAISO found itself with an abundance of un-curtailed hydroelectricity that competed with solar generation.[397] A similar dynamic played out in 2011 following significant precipitation in the Pacific Northwest, as shown in Figure 5.8.[zzz]

[zzz] In Figure 5.8, Off-peak is 10 p.m. to 6 a.m. on Monday through Saturday and all hours on Sunday. Mid C is Mid-Columbia, COB is California-Oregon Border, and NOB is Nevada-Oregon Border.

Figure 5.8. Negative Northwest Off-Peak Daily Spot Prices ($/MWh) in 2011[398]



5.3.3 State Actions Impacting Wholesale Markets

There is growing concern about the impact of state government intervention in wholesale markets, such as the creation of ZEC programs to keep nuclear plants in operation, as well as RPS and other state policy requirements. This concern was reflected in comments at the May 1–2, 2017 FERC Technical Conference on state policies in the three eastern wholesale markets:[aaaa]

> [Roy Shanker, independent consultant]: It is difficult to identify any element in the wholesale electric market (energy, capacity, ancillary services and transmission) that is not being directly and materially impacted by discriminatory mandates driven by state policy actions. Price taking energy and capacity offers linked to these mandates directly impact price formation. The intermittent nature of virtually all RPS resources requires material modification of dispatch and significant increases in flexible resources and associated ancillary services.[399]
>
> [William Hogan, Harvard University]: The increasing impact of Federal and state policies to support particular technologies, raises questions about the viability of wholesale power markets.[400]
>
> [Susan Tierney, Analysis Group]: These state policies can and often do affect the price of electricity in wholesale power markets, and the entry, exit and cost of operations of electric generating resources…there is no reason to expect that state decision makers will make

[aaaa] The full transcript of (and all written statements from) this technical conference is available on FERC's website. FERC Technical Conference, "Docket No. AD17-11-000", May 1-2, 2017.

> determinations that singularly focus on economic efficiency and the continued viability of wholesale capacity-market designs ahead of other all objectives… Already, we see that in a market that depends upon the flow of private capital and diversity in the asset mix, some suppliers of capacity resources (including demand-response and nuclear generation) have recently decided that the markets are not producing financial outcomes consistent with the requirements of private capital markets… I remain concerned that the current centralized wholesale capacity markets in PJM, NYISO and ISO-NE will not be sustainable, from an economic, financial and political point of view and in light of states' policies and preferences.[401]
>
> [Cliff Hamel, Navigant Consulting]: [P]roblems in the current centralized [capacity] market approach are fundamental.[402]
>
> [Samuel Newell, The Brattle Group]: The centralized wholesale markets do not, however, and should not be expected to meet goals they were not designed to meet. Many states now have far-reaching carbon and clean energy goals. Yet today's centralized energy, ancillary services, and capacity markets are mostly not designed to differentiate generation resources based on their unpriced carbon emissions or other unpriced attributes.[403]
>
> [Lawrence Makovich, IHS Markit]: In summary, out-of-market interventions cause predictable distortions and consequences, including:
>
> > 1. Reduced market-based cash flows for non-peaking generating resources, causing lower investment in electric generating production efficiency.
> >
> > 2. Uneconomic displacement of lower cost energy production causing a shift toward a less cost-effective fuel and technology mix and resulting in higher overall average electricity supply costs.
> >
> > 3. Less supply diversity causing more generation production cost and availability risk.
> >
> > 4. Premature retirements of low CO2 emitting resources, causing replacement with higher CO2 emitting resources that subvert market intervention policy goals.[404]

While this panel of economists commented on these effects on the wholesale markets resulting from state policies, members of a panel of state officials at the same FERC Technical Conference clearly said their states will continue to pursue their policies:

> [Jeffrey Bentz, New England States Committee on Electricity]: States aren't interested in having markets just for the sake of having markets…[405]
>
> [Angela O'Connor, Department of Public Utilities of Massachusetts] […] what the legislature requires us to do we have to do…[406]
>
> [Sarah Hofman, Vermont Public Service Board]: […] we cannot tell what our legislators [what to] do. And so they are going to have policies and it doesn't matter what anybody here or any place else says, they will have policies that set the stage for what the state wants and that's what legislators are for.[…] there is no question that state lawmakers will continue passing legislation that sets public policy. It is now our challenge to continue to work together to find effective ways to carry out those policies while also continuing to benefit from competitive wholesale markets.[407]

Tony Clark recently expressed similar views on the original policy assumptions behind the creation of centrally-organized wholesale markets:

> Affordable power was the goal. The current markets are still procuring affordable power but many state public policy makers no longer see that as the only goal. It is little wonder we hear some decry that the markets are not delivering what people want. It is because they were never designed for job creation, tax preservation, politically popular generation, or

anything other than reliable, affordable electricity. To the degree policy makers and elected officials have moved the goal posts, it is time to consider rational pathways forward.[408]

5.4 Wholesale Electricity Markets Looking Forward

Changes in the centrally-organized markets must catch up to the broad technology-driven and policy-driven electricity market dynamics identified in the April 14 memo. Overall, centrally-organized wholesale electricity markets are effective at driving energy prices toward suppliers' short-run marginal costs. However, the revenue insufficiency problem has become more pronounced in recent years.

Generator profitability could become a public policy concern if so much generation is financially challenged that the reliability or resilience of the BPS become threatened. New market structures may be necessary to reflect these market dynamics, particularly in an industry in which suppliers with high fixed capital costs and relatively low marginal costs often struggle to recover their long-run average costs.

In addition, while markets as currently designed do not explicitly recognize or compensate system resilience, RTO/ISOs are considering ways to better support system resilience objectives in the same way that they explicitly recognized and administratively incorporated reliability standards into dispatch practices in the past. For example, the variety of problems that arose during the Polar Vortex (as discussed in Section 4) caused PJM and ISO-NE to change their capacity market rules to ensure generator performance during scarcity conditions.[409] [410]

In summary, the debates surrounding wholesale markets are complex and multifaceted, but the institutions and the grid itself have historically proven flexible, strong, and able to adapt. Questions about revenue sufficiency and resilience must be addressed quickly, before the fast-moving evolution of our power system outpaces our ability to understand and manage it responsibly.

6 Affordability

The April 14 memo asked whether the loss of coal, natural gas, nuclear, and hydroelectric baseload power is making the grid less affordable. There is no widely accepted metric for an "affordable" grid or an "affordable" electricity bill. DOE's GMI defines affordability as "maintain[ing] reasonable costs to customers."[411] Typically, the meaning of "affordable" is contextual, i.e. dependent on the size of a consumer's household budget. This indicator of energy affordability can be represented as *energy burden,* which is a household's annual spending on energy as a percentage of its gross annual income.[412] [413]

Because electricity is an important energy service, it can be broken out as "electricity burden."[bbbb] In 2011, the median electricity burden for all households was four percent, but it averaged 8.3 percent for low-income households and 2.9 percent for non-low-income households.[414] [415] [416] For low-income families, more spending on energy bills translates into less spending on other expenses, such as food, health care, and education.[417] The limited increases in electricity rates suggest that electricity bills have not become less affordable for most customers. However, changes in cost allocation and rate designs could have disparate effects on bills for different groups of customers.

For example, utilities raising fixed charges to counterbalance decreases in revenues from energy efficiency gains could disproportionately impact low-consumption customers, for whom fixed charges comprise a larger portion of the bill. Customers on fixed incomes and those who rely on electricity-intensive medical devices may have an acute need to maintain affordability.[418] Most states and utilities offer programs like concessionary rates for these customers, and ensuring affordability options for vulnerable customers remains a priority as electricity stakeholders explore market, regulatory, and rate reforms to accommodate an evolving grid.

Low electricity prices can also boost businesses' competitiveness and bring new economic activity to an area, as evidenced by companies locating electricity-intensive industrial facilities, such as server farms, to regions with low, stable electricity prices.[419] [420] [421] [422] Today, many businesses are more actively managing their energy costs by investing heavily in energy efficiency, energy management systems, solar PV installations, and direct PPAs with VRE providers.[423] Industrial electricity prices are typically close to wholesale prices because providing electricity to high-voltage, high-use industrial customers is less expensive and more efficient than serving distribution-level customers.[424] Thus, low wholesale electricity prices can allow businesses and industrial customers to thrive, support job growth, and drive economic development.[425]

6.1 Affordability of Generation Portfolios

The affordability of a given generation portfolio is largely shaped by region- and state- specific market structures. Merchant investment decisions (where applicable) and regional resource availability (for example, NGCC has a lower levelized cost of electricity (LCOE, the per-MWh cost of building and operating assets over their lifetime) in the Gulf States where gas is abundant than it has in the North

---

[bbbb] However, this is complicated by the fact that electricity usage varies significantly from region to region, so the electricity burden would be much higher in regions that use electricity for heating and cooling, as is common in the West and South. In addition to electricity, e*nergy* burden includes direct fuel use, such as natural gas or propane for cooking and heating, and can vary based on a household's activities, appliances, and location.

Central states) contribute to regional variation in charges to end-users. [426] The Energy Information Administration estimated in the Annual Energy Outlook for 2017 that the BPS (generation and transmission) comprises roughly two-thirds of the total average price of electricity. Generation costs accounted for 57 percent of the average price of electricity in 2016, compared to distribution's 32 percent and transmission's 11 percent.[427]

In vertically integrated areas, state PUCs seek to avoid uneconomic outcomes and ensure affordable service to customers[428] by requiring VIEUs to submit IRPs in which they consider least-cost, long-term plans for providing service including, among other things, LCOE.[429] The IRP must also account for any additional state-mandated requirements such as energy efficiency resource standards or RPS.[430] Notably, VIEU assets are usually guaranteed the recovery of investment and operational costs regardless of whether they would prove to be cost-competitive in a short-run marginal cost market environment.[431] [432]

By contrast, in some of the centrally-organized markets (e.g., most of the states in PJM, ERCOT, all but two in ISO-NE, NYISO, and Illinois for MISO), the generation portfolio is determined by the wholesale market itself (subject to any generation and demand-side mandates) rather than a state-overseen IRP by the VIEU.[cccc] Merchant generators make investment decisions by comparing an asset's expected lifetime costs with the expected revenues from any PPAs, financial incentives such as tax credits, and sales in wholesale energy and capacity markets. Lifetime costs considered by merchant generators include fixed investment costs and operational costs.

6.2 The Wholesale-Retail Disconnect

Tracing the relationships between wholesale and retail prices is difficult because ratemaking practices vary widely from state to state, and there are many other contributing factors involved besides the wholesale cost of electricity.[433] [434] Retail rates include a variety of charges that are not included in the bulk electricity charges passed through by RTO/ISOs or VIEUs. These include components of the transmission costs not captured in the RTO prices (such as state-regulated transmission investments), payments that the distribution utility makes to merchant transmission suppliers, various fixed charges, customer service, state and local sales taxes and franchise fees, and public benefits charges.[435]

Retail electricity bills can also include additional costs to support state policy goals—such as RPS, energy efficiency resource standards, or programs to promote use of distributed energy resources, among others.[436] Most utilities have undertaken substantial programs to modernize their distribution systems, and a significant subset have invested in infrastructure needed to integrate higher levels of distributed energy resources.[437] Under established cost-of-service ratemaking principles, these costs are typically allocated to retail customers and periodically examined by regulators.

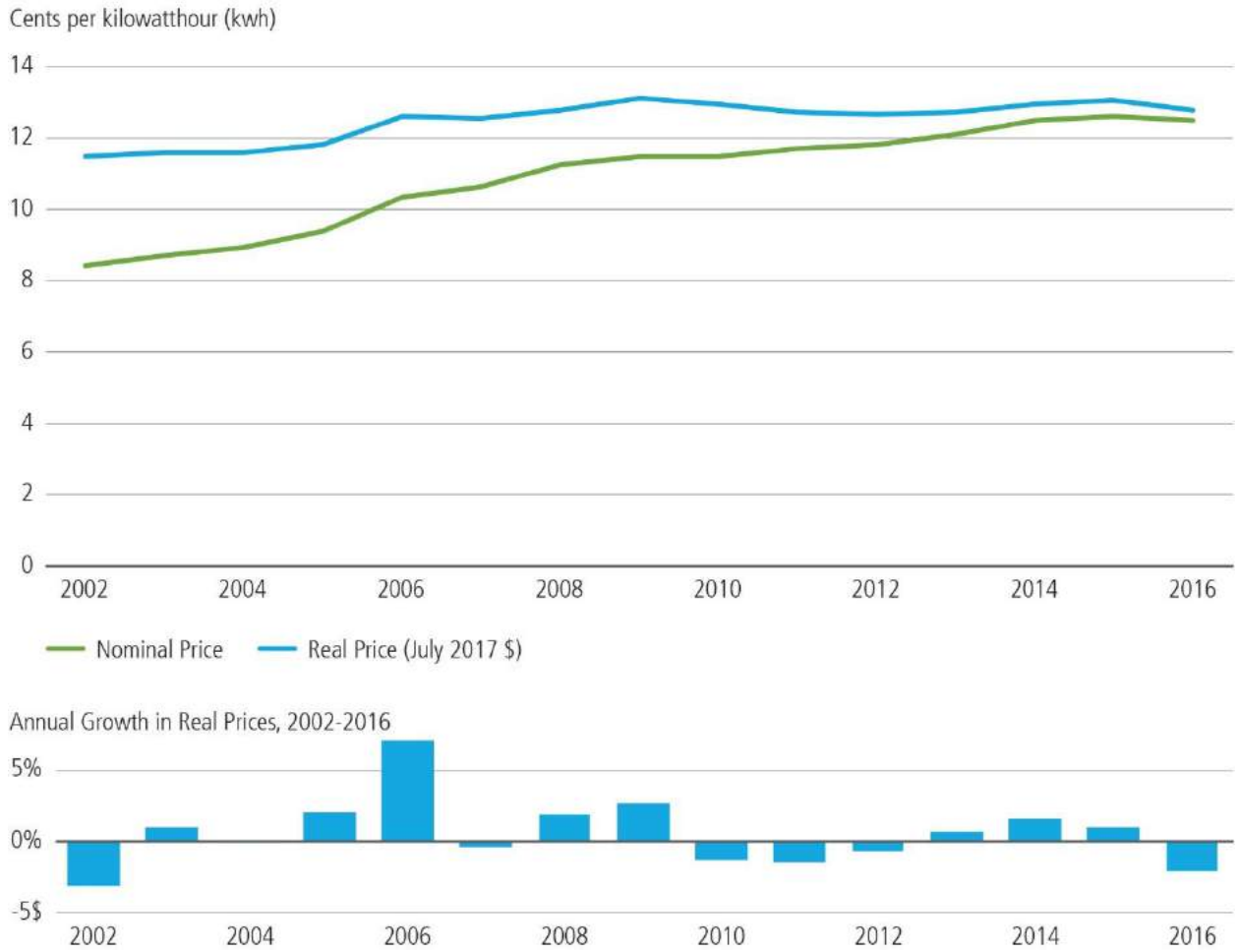
The wholesale-retail electricity price disconnect means that, in most areas, the conventional generation retirements can affect wholesale rates but have little or no immediately visible impact on retail rates.

[cccc] Many state, regional, and Federal policies can impact the expected profits for merchant generators, including environmental regulations; carbon trading programs; tax credits; and state procurements, mandates, or other mechanisms that take generation or demand-side resources out of markets available to merchants and/or subsidize those resources.

However, despite the difficulty in attributing retail price impacts to wholesale changes, considering the trends in both wholesale and retail prices can provide greater understanding of affordability.

On average, national retail electricity rates have been roughly flat for more than a decade, and rates have closely followed the historical average since 1960.[dddd] [438] Retail rates in nominal dollars have been increasing at a low annual rate for approximately two decades, while the real retail price has stayed relatively constant over the last decade, as shown in Figure 6.1. From 2011 to 2016, nominal residential prices increased at an average of 1.9 percent annually, about the same rate as overall inflation.[439] In 2016, the national average retail electricity price declined for the first time since 2002, with residential customers paying a national average of 12.55 cents/kWh.

Figure 6.1. Average U.S. Residential Sector Retail Electricity Prices over Time[440]

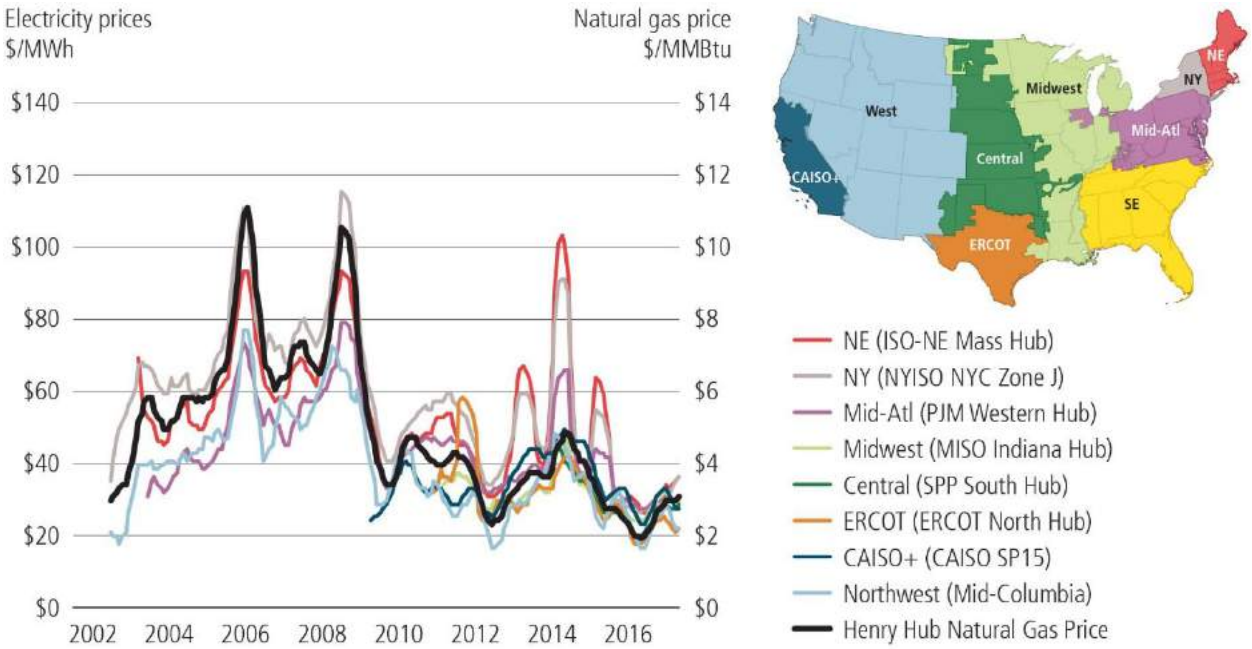


[dddd] The use of national averages for this analysis provides a broad picture, but limits insight into regional and state-level impacts of BPS changes that may lead to higher-than-average retail rate increases among some customers and utilities. National averages mean little to subsets of ratepayers seeing significant retail rate increases or those who have faced consistently high bills. Even use of state-level retail averages can mask exceptions that greatly vary from the average. For example, California residents who live near the coast enjoy a temperate climate with limited need for cooling or heating. In contrast, those living inland see very hot summers that require high use of air conditioning and thus see high electric bills. A more thorough analysis would consider affordability and rate increases at a more granular level.

Average retail prices vary widely across states and regions, with New England, California and the Mid-Atlantic paying the highest rates.[441] However, a comparison of electricity rates alone can be misleading; for instance, California's average residential electricity rate is over 18 cents/kWh (one of the highest in the Nation), but due to low average residential consumption, the average California electricity bill is only $95/month, ranking it in the bottom third of the Nation. By comparison, Washington state has the lowest average retail rates in the Nation at less than nine cents/kWh (less than half the average rate in California), but because of higher consumption, residential customers in that state see average bills of $95/month, the same average electricity bill as in California.[442] [443]

It is not yet clear what impact recent coal, nuclear, and natural gas plant retirements will have on customer bills in the future, nor how the continuing trend of retirements will affect the overall cost of the BPS, which will ultimately be borne by ratepayers. Natural gas generation has proven to be a strong competitor with coal and nuclear power because natural gas prices have fallen over the past decade. Wind and solar generation have also increased, and while their capital costs are much higher than those of natural gas (particularly if normalized by capacity factor), their marginal cost is nearly zero.[444] Changes in the BPS since 2002—lower demand, lower natural gas prices, and growth in VRE—have reduced wholesale electricity prices, as shown in Figure 6.2.[445]

Figure 6.2. Average Wholesale Electric Costs/MWh Have Fallen between 2002 and 2016[446]

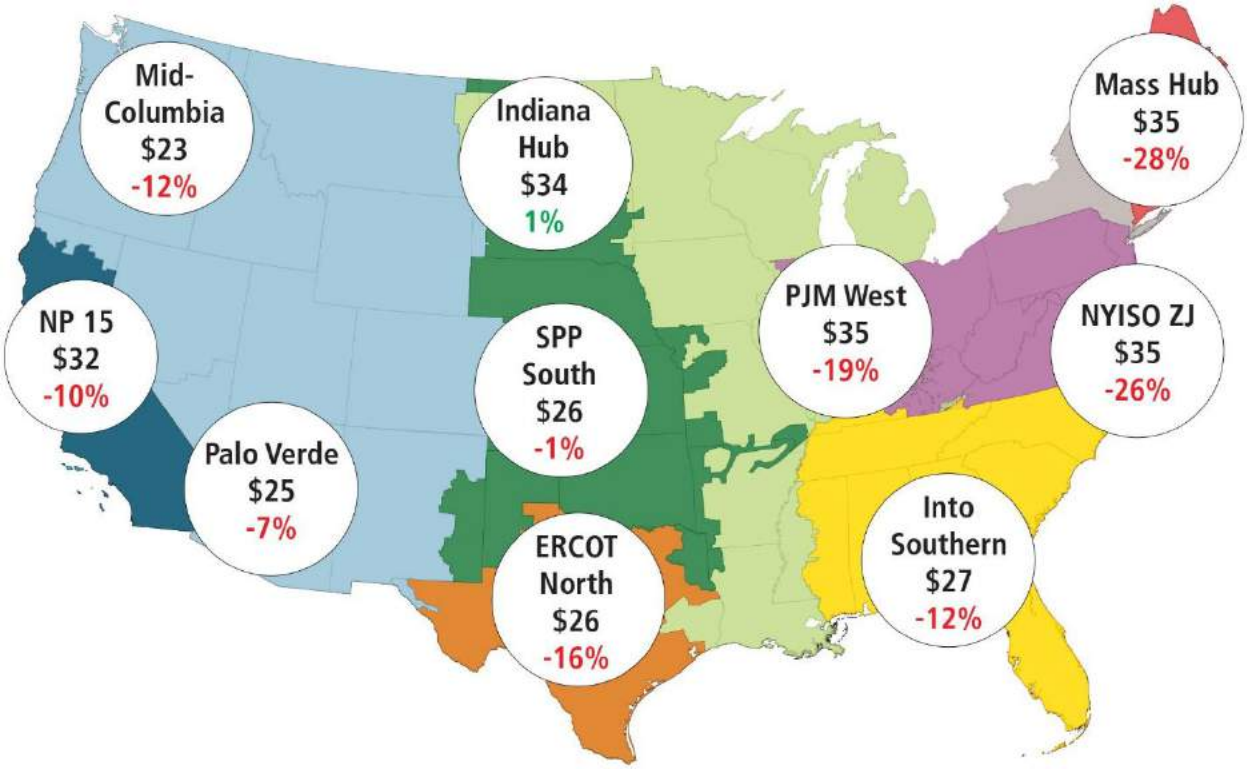


From 2002–2016, wholesale electricity prices have increasingly tracked natural gas prices, and as natural gas generation has increased over time, the differences in price between regions have also decreased (e.g., prices in NYISO and PJM are much closer in 2016 than in 2004).

Figure 6.3 illustrates wholesale prices at electricity trading hubs, emphasizing 2016 prices on a regional basis as derived by FERC staff.[eeee] FERC notes in its 2016 *State of the Markets* report that prices were down in 2016 from 2015, and that prices in PJM were the lowest they have been since the RTO formed in 1999.[447]

[eeee] Derived by FERC staff from S&P Global Intelligence data. Prices are a simple average of day-ahead, on-peak physical prices.

Figure 6.3. Day-Ahead, On-Peak Wholesale Electric Prices Reach Near-Record Lows in 2016[448]



FERC's most recent *State of the Markets* report shows that all areas of the United States are experiencing low wholesale electricity prices. In 2016, prices were highest in the Northeast, Mid-Atlantic, and Midwest and were lowest in the Northwest. Historically, wholesale prices would show much more regional variation. The dollar values are average 2016 day-ahead on peak prices; the percentages indicate the change from 2015 to 2016.

While wholesale electricity prices have tracked natural gas price trends, the impacts of other generation trends on affordability are less obvious.[449] Because coal, hydro, and nuclear plants have historically had relatively stable and predictable fuel costs, these power plants have provided a valuable hedge against the price volatility of natural gas and oil. Today, nuclear, hydro, and VRE all serve as hedges against generation whose fuel cost is more volatile and represents a larger portion of the total delivered price (i.e. natural gas and oil). For example, the variable operating, maintenance, and fuel costs of hydroelectric and nuclear average just $5/MWh and $12/MWh, respectively, compared to $41/MWh for NGCC and $34/MWh for coal.[450] Increasingly, VRE also performs a price stabilizing role—wind, solar PV, hydropower, and geothermal generation offer near zero-marginal-cost electricity. To the degree that VRE and nuclear can stabilize the short run cost of bulk power, those resources could also improve the month-to-month manageability of customer bills.

Among the nine regions examined in this study, the CAISO+, Midwest, ERCOT, and Central regions have the most non-hydro VRE generation today. RPS compliance costs were found to total $2.6 billion in

2014, averaging $12/MWh for VRE and equating to 1.3 percent of average retail electricity bills.[ffff] [451] The actual effects of zero-marginal cost electricity on consumers' bills is situational, and growth in VRE can drive additional costs, including transmission and integration costs.[452] [453] Because many utility-scale VRE plants are built in locations distant from load centers, they sometimes require major transmission additions to connect the remote generation to the rest of the grid and to load centers. Over the past five years, a portion of the 24,000 miles of new transmission built (about twice the number of miles added from 2006–2010) and $102 billion invested to strengthen the grid and interconnect new generation has been made to interconnect VRE.[454] [455] Transmission investments (regulated or merchant) can increase bulk power costs and therefore increase customers' retail bills to the extent that they are not offset by savings attributable to access to lower-cost generation or reduced congestion costs.

Higher levels of VRE penetration also require system integration services, such as additional ERS. It is unclear how the costs of these integration requirements will affect wholesale electricity costs as VRE penetrations continue to increase. In addition, as the PTC for wind generation expires and the ITC for residential solar PV installations reduces in the coming years, their costs relative to other resources will rise. However, declining wind and solar capital costs and higher productivity will likely somewhat offset these losses, albeit to an unknown degree.[456] [457] [458] [459]

Finally, several states have created subsidies to favor or retain nuclear generation. If such subsidies are being funded by taxpayer dollars – like the PTC and ITC – rather than a charge to electricity customers, this will affect wholesale costs in some way, but will probably have little discernable effect on the customers' retail electricity bills. However, if subsidies for power plant retention are funded as a direct charge to retail electricity customers, electricity bills could rise and affordability could decrease.

Overall, ISOs and RTOs face many challenges that ultimately affect the allocation of transmission and integration costs when they make decisions on how to spread those costs among cost-causers, reliability and other service providers, and consumers, as well as decisions on how to keep cost allocation practices up to date as the generation mix, transmission capacity, and load evolves over time.[460] [461] [462] [463]

6.3 Affordability Looking Forward

There appears to be little near-term risk that natural gas prices will rise significantly and thereby reduce electricity affordability. However, natural gas is an extractive commodity traded internationally—prices are affected by policies impacting how the resource is produced, and prices show periodic regional, seasonal, or local price spikes, and even sustained price increases. It is reasonable to expect continuing regional differentials between natural gas delivered costs, reflecting differences in proximity to natural gas production fields, production costs, and deliverability (including the effects of pipeline or liquefied natural gas deliverability constraints). If natural gas prices rise, wholesale electricity costs are likely to rise in regions where natural gas remains the marginal fuel in a significant number of hours. This would be true for both RTO/ISO and non-RTO/ISO regions. It is unclear how rising natural gas prices and

[ffff] Studies on RPS compliance costs do not fully capture the "all-in" costs that the ratepayer (and taxpayers) ultimately bear. These other costs are harder to measure, but may not be insignificant. They may be harder to quantify for many reasons, such as having multiple drivers behind those investments and various distribution-level grid modernization investments (e.g., smart meters and others that are touted to aid VRE integration). New transmission (other than the direct transmission interconnection charged to the renewable generation project and thus reflected in their PPA), as well as effects of VRE variability on the dispatchable fleet, are other examples of costs often not included in grid integration cost studies. Costs of various tax and other subsidies are also not counted.

additional VRE generation would affect the large-scale displacement of coal and nuclear generation, and ultimately, electricity affordability for affected consumers.

The variety of generation portfolios operating throughout the U.S. lends itself to further study. To date, limited work has focused on the affordability of the BPS as a system or portfolio—relatively more attention has focused on retail electricity prices[464] or the stand-alone cost of generation technologies (such as LCOE). Some research has focused on analysis of system-wide LCOE,[465] but more can be done.

Looking forward, another potential challenge to affordability is determining how the proliferation of distributed PV across much of the Nation is changing the cost structure for non-participating customers. A growing body of research considers whether and how distributed PV users continue to benefit from their grid connection for balancing services and energy storage, as well as how to reallocate utility energy, capital, and system costs and rates fairly among all users. Concerns about more customers installing distributed PV under net metering tariffs,[gggg] which potentially shifts costs and increases the burden on non-distributed PV customers, have caused multiple states to re-open their net metering tariff processes and, in some cases, implement new policies. However, some studies have quantified the retail rate impacts of net metering to all residential customers (i.e., participants and non-participants) and found that current and projected levels of net metering have very little impact, especially compared to broader drivers of retail rate increases in the electric industry.[466]

[gggg] According to the EIA, "net metering tariffs enable customers to use the electricity they generate in excess of their consumption at certain times to offset their use of electricity from the grid at other times. These tariffs are designed to encourage distributed renewable generation. These arrangements describe how an electric utility customer who installs a qualifying generator (typically a rooftop solar array, less often a small wind turbine, or a small combined heat-and-power system) will be compensated by their utility for the electricity they generate in excess of their consumption." https://www.eia.gov/todayinenergy/detail.php?id=6190

7 Policy Recommendations

The April 14 memo asked staff to "not only analyze problems but also provide concrete policy recommendations and solutions." To that end, DOE staff prepared a list of recommendations below. Some actions fit squarely within DOE's authority, while others might fall to other government agencies or private organizations.

Wholesale markets: FERC should expedite its efforts with states, RTO/ISOs, and other stakeholders to improve energy price formation in centrally-organized wholesale electricity markets. After several years of fact finding and technical conferences, the record now supports energy price formation reform, such as the proposals laid out by PJM[467] and others.[468] Further, negative offers should be mitigated to the broadest extent possible.

Valuation of Essential Reliability Services (ERS): Where feasible and within its statutory authority, FERC should study and make recommendations regarding efforts to require valuation of new and existing ERS by creating fuel-neutral markets and/or regulatory mechanisms that compensate grid participants for services that are necessary to support reliable grid operations. Pricing mechanisms or regulations should be fuel and technology neutral and centered on the reliability services provided. DOE should provide technical and policy support that strengthen and accelerate these efforts.

Bulk Power System (BPS) resilience: DOE should support utility, grid operator, and consumer efforts to enhance system resilience. Transmission planning entities should conduct periodic disaster-preparedness exercises involving electric utilities, regional offices of Federal agencies, and state agencies. NERC should consider adding resilience components to its mission statement and develop a program to work with its member utilities to broaden their use of emerging ways to better incorporate resilience. RTOs and ISOs should further define criteria for resilience, identify how to include resilience in business practices, and examine resilience-related impacts of their resource mix.

Promote Research and Development (R&D) of next-generation/21st century grid reliability and resilience tools: DOE should focus R&D efforts to enhance utility, grid operator, and consumer efforts to enhance system reliability and resilience. DOE R&D opportunities include the following activities:

- Develop grid technical tools to facilitate new-generation technologies' operations to support BPS reliability (e.g., by enabling technologies to provide ERS), and maximize use of the DOE national laboratories.
- Expand cooperation on grid reliability across North America, including working with NERC to further enhance the reliability of our shared BPS through technical engagement with Mexico and Canada.
- With the National Science Foundation, sponsor the development of new open-source software for the next-generation electric grid research community.
- Focus R&D on improving VRE integration through grid modernization technologies that can increase grid operational flexibility and reliability through a variety of innovations in sensors and controls, storage technology, grid integration, and advanced power electronics. The Grid Modernization Initiative should also consider additional applications of high-performance computing for grid modeling to advance grid resilience.

Support Federal and regional approaches to electricity workforce development and transition assistance: In partnership with other agencies and the private sector, DOE should facilitate programs

and regional approaches for electricity sector workforce development. Unemployed workers nearing but not yet eligible for retirement may have difficulty retraining after careers built on specialized skills that may be in declining demand. Where possible, Federal agencies should leverage existing government, nongovernment, labor, and industry workforce consortia.

Energy dominance: Executive Order 13783 (Promoting Energy Independence and Economic Growth) outlined an approach to promote the clean and safe development of energy resources while at the same time minimizing regulatory barriers to energy production, economic growth, and job creation. The Order called for a rescission of certain energy and climate related policies, rescinded specific reports, and ordered the review of key environmental regulations. While DOE is not the main agency tasked in the Order, it should continue to prioritize energy dominance and implementing the Executive Order broadly and quickly.

Infrastructure development: DOE and related Federal agencies should accelerate and reduce costs for the licensing, relicensing, and permitting of grid infrastructure such as nuclear, hydro, coal, advanced generation technologies, and transmission. DOE should review regulatory burdens for siting and permitting for generation and gas and electricity transmission infrastructure and should take actions to accelerate the process and reduce costs. Specific reforms could include the following:

- *Hydropower*: Encourage FERC to revisit the current licensing and relicensing process and minimize regulatory burden, particularly for small projects and pumped storage.
- *Nuclear Power*: Encourage the NRC to ensure the safety of existing and new nuclear facilities without unnecessarily adding to the operating costs and economic uncertainty of nuclear energy. Revisit nuclear safety rules under a risk-based approach.
- *Coal Generation*: Encourage EPA to allow coal-fired power plants to improve efficiency and reliability without triggering new regulatory approvals and associated costs. In a regulatory environment that would allow for improvement of the existing fleet, DOE should pursue a targeted R&D portfolio aiming at increasing efficiency.

Electric-gas coordination: Utilities, states, FERC, and DOE should support increased coordination between the electric and natural gas industries to address potential reliability and resilience concerns associated with organizational and infrastructure differences. DOE and FERC should support well-functioning commodity markets for natural gas by expeditiously processing liquefied natural gas export and cross-border natural gas pipeline applications.

8 Areas for Further Research

DOE staff identified several research topics that are relevant to the April 14 memo and merit further in-depth analysis. Some topics may be appropriate for offices within the Department, national laboratories, academia, other government agencies, or private organizations.

Market structure and pricing

- Study mechanisms for enabling equitable, value-based remuneration for desired grid attributes—such as ERS, fuel availability, high resilience, low emissions, flexibility, etc.—with alternative market and non-market structures. This research could assess potentially under-recognized contributions from baseload power plants, using fuel-neutral metrics and values relevant to analyze all resource options.
- Evaluate ongoing capacity market reforms. Several of the Nation's electricity markets use mandatory capacity markets to procure capacity for future years and ensure resource adequacy. The design of these constructs has been the subject of near-constant debate within the RTO/ISOs and before FERC. After undergoing substantial changes from 2014–2015, capacity markets have come under new scrutiny in light of recent actions by restructured states to preserve or promote certain resources or resource types and to further state policy goals.
- Explore market operations in a higher VRE/low marginal cost system, and examine recent changes in energy price trends—including the drivers of wholesale electricity prices in the context of limited load growth—quantifying the relative contributions of fossil fuel prices. With significant amounts of near-zero marginal cost generation available, security-constrained economic dispatch of BPS based on marginal costs may not sufficiently compensate resources for all fixed and variable costs. Academic and other research should be expanded in this area, to include capacity market reforms and the role of capacity markets in a higher VRE/low marginal cost system.

Reliability and resilience

- Develop policy metrics and tools for evaluating BPS-wide provision of resilience and considering all aspects of the electricity system that contribute to resilience, including regional generation characteristics, imports and exports, fuel supply and storage, transmission capability, DR, electricity storage, inertia, and other factors that determine the ability of grid operators to provide reliable electricity supplies.
- As PJM notes, "criteria for resilience are not explicitly defined or quantified today."[469] Each RTO/ISO should strive to explicitly define resilience on its system and conduct resource diversity assessments to more fully understand the resilience of different resource portfolios. Federal, state, and local work to define and support system-wide resilience is also needed.
- EIA and NERC should examine ways to improve power generator fuel delivery data collection; additional data on fuel deliveries and potential disruptions would further improve forecasting necessary for electric reliability planning.

Cost and affordability

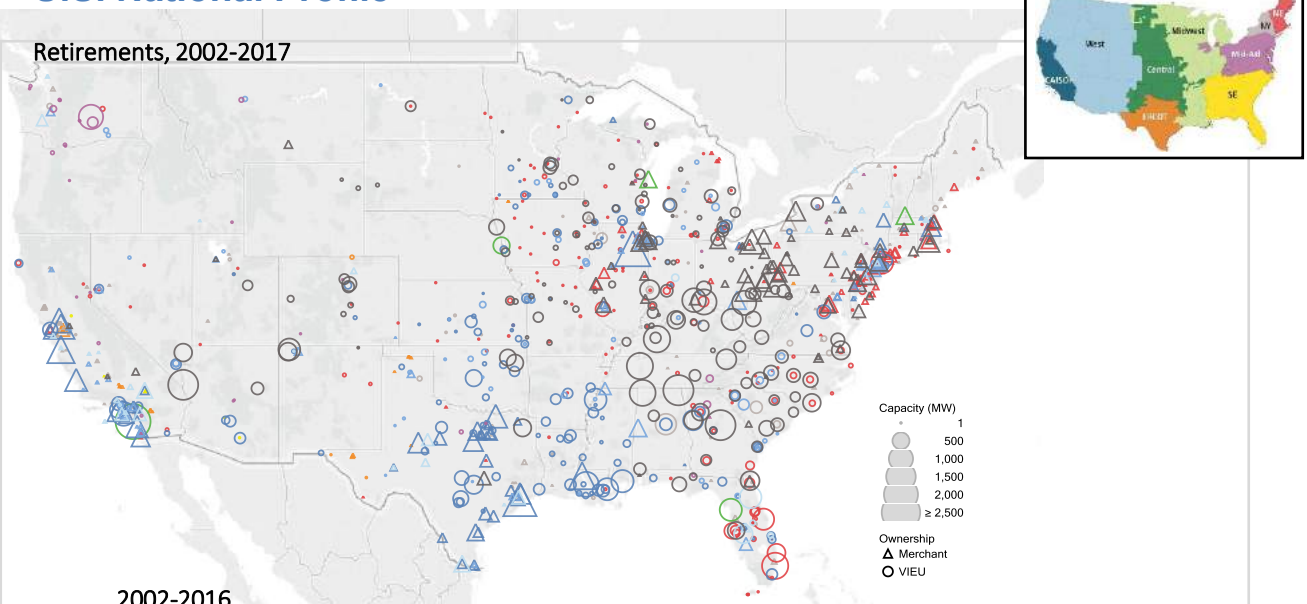
- Estimate the bulk power system-wide costs of different generation mixes, also considering the sensitivity of system costs to various fuel price fluctuations. Further, examine the relationship between wholesale and retail electricity rates to understand the present disconnect.
- On a regular basis, update the EIA analysis of subsidies and support for electricity production (most recently updated using FY 2013 data).[470]

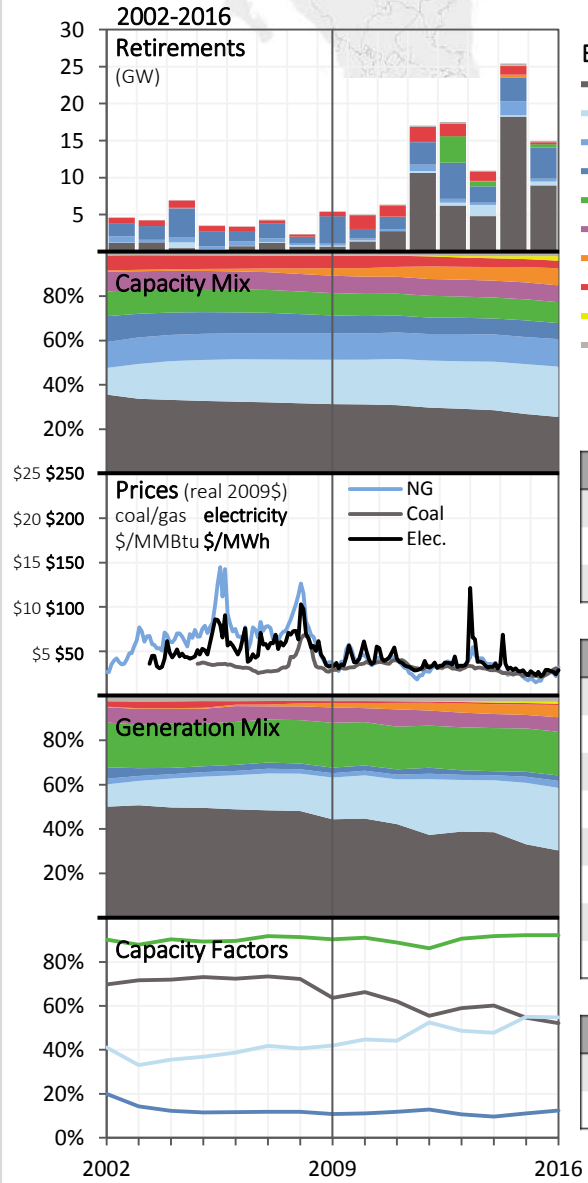
Regulatory

- Explore the potential for utilizing existing Federal authorities under the Federal Power Act and the DOE Organization Act, among others, to ensure system reliability and resilience.
- Explore costs and benefits of states applying cost-of-service regulation to specific at-risk plants that contribute to grid resilience. In centrally-organized wholesale markets, these resources may sometimes be unable to recoup all costs of generating electricity—especially capital investments that are needed to ensure long-term viability.

Appendix A: National and Regional Profiles

U.S. National Profile





Energy Sources

- Coal
- Natural Gas (CC)
- Natural Gas (CT)
- Natural Gas (ST)
- Nuclear
- Hydro
- Wind
- Oil
- Solar
- Other

Notes:
Capacity values are summer capacity. Data for utility-scale resources only (1+ MW nameplate capacity). Natural gas technologies: CC = combined cycle, CT = combustion turbine, ST = steam turbine. Ownership type: VIEU = vertically integrated electric utility. Map includes 2017 Q1 actual and Q2-4 announced retirements. Prices: Natural gas = Henry Hub, Coal = Central App., Electricity = PJM Western Hub.
*Total % Capacity Reduction calculation: retired capacity / (retired capacity + 2016 operational capacity)

Total Capacity & Generation

	2002	2016
Capacity (MW)	884,930	1,056,710
Generation (GWh)	3,860,853	4,085,765

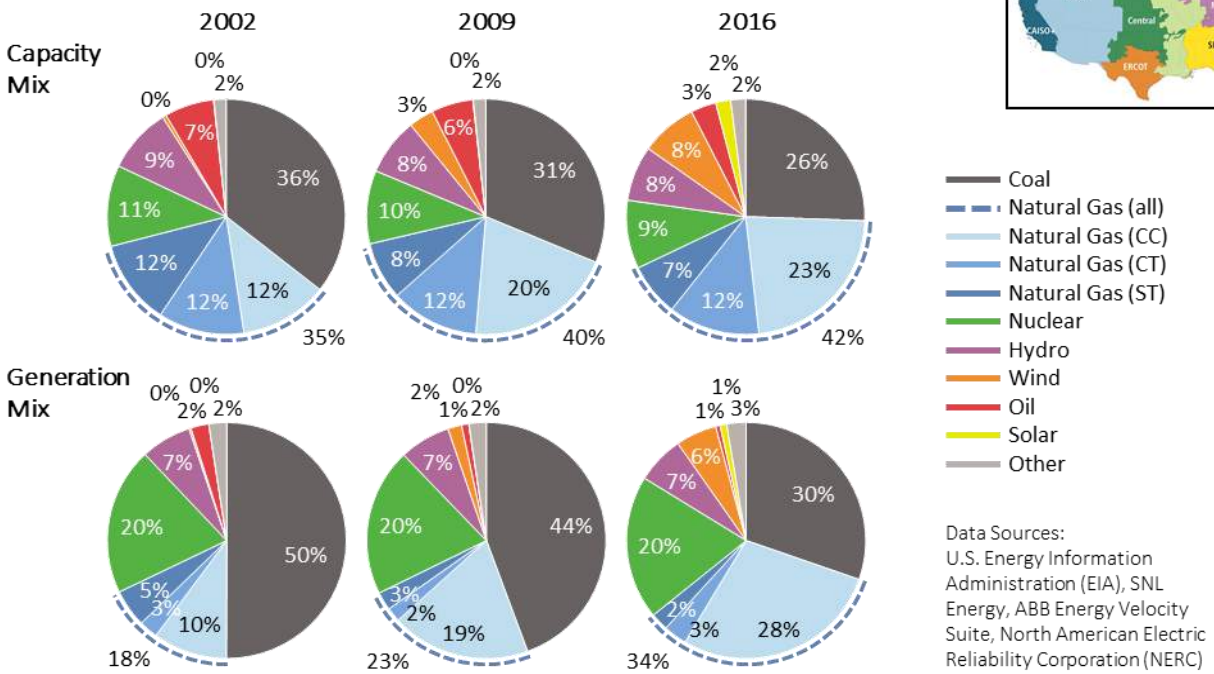
Retirements by Energy Source, 2002-2016

	# of Generators	MW
Coal	531	59,392
Natural Gas	965	50,593
Nuclear	6	4,667
Oil	1,083	14,980
Hydro	140	283
Other (all other sources)	471	2,147
*Total % Cap. Reduction**	*11.1%*	132,062

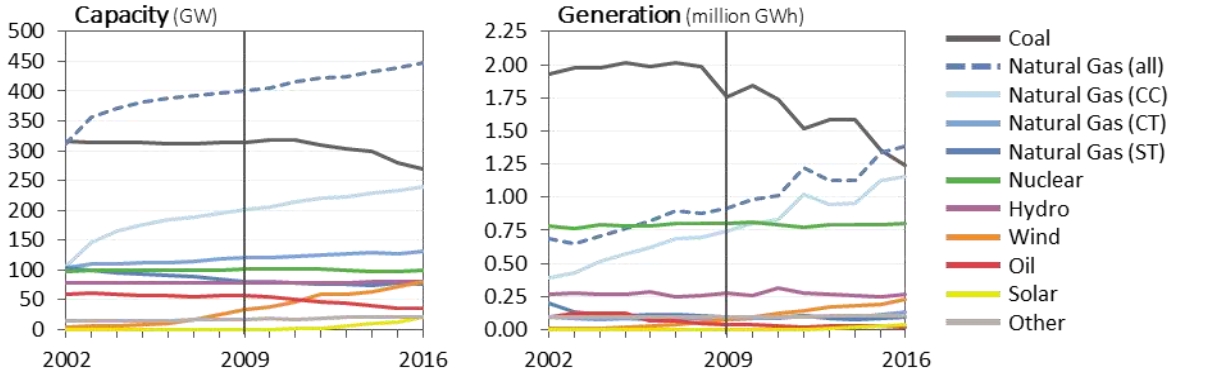
NERC Reserve Margin, 2017 (2016 LTRA)

	Target	Actual
Total NERC Area	--	23.58%

U.S. National Profile



Data Sources:
U.S. Energy Information Administration (EIA), SNL Energy, ABB Energy Velocity Suite, North American Electric Reliability Corporation (NERC)



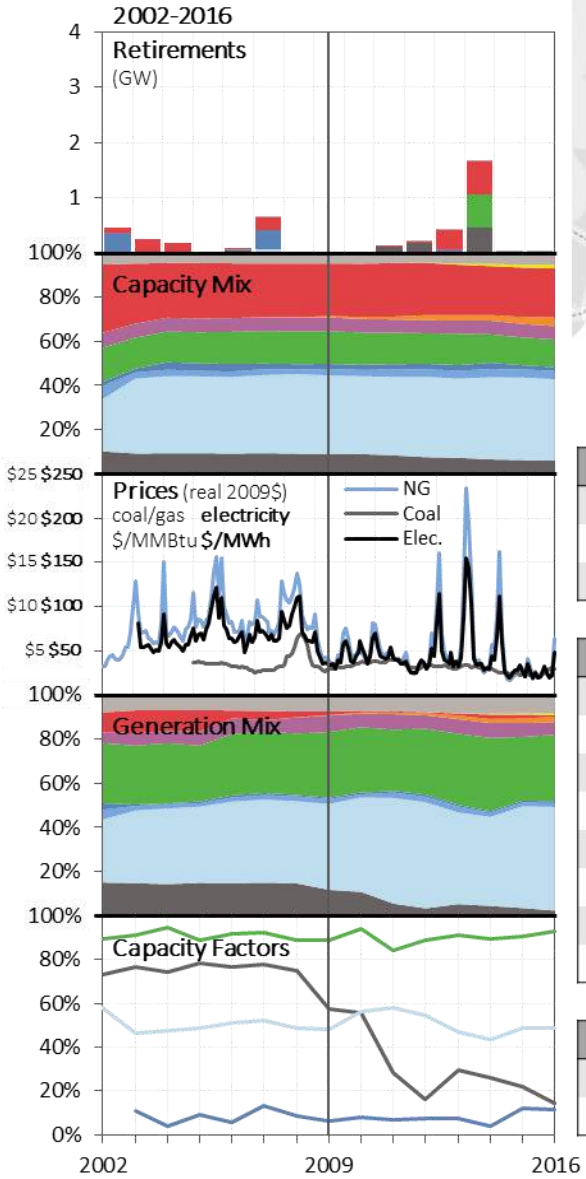
Capacity & Generation by Energy Source, 2002 & 2016

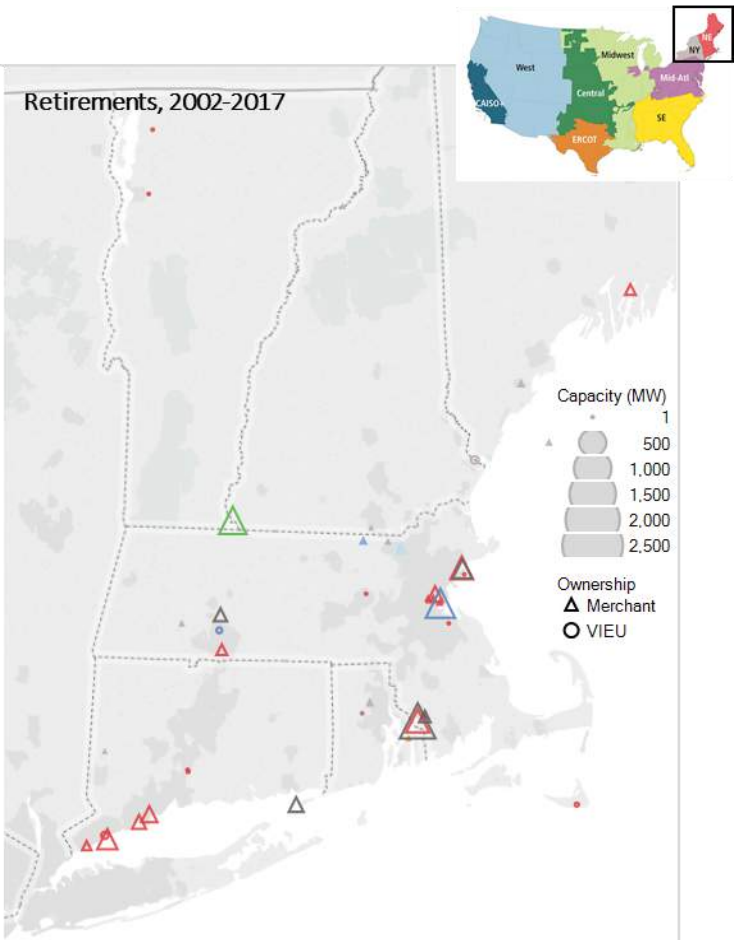
	Capacity				Generation			
Energy Source	**2002 GW**	**%**	**2016 GW**	**%**	**2002 thous. GWh**	**%**	**2016 thous. GWh**	**%**
Coal	315.4	*36%*	270.1	*26%*	1,933.1	*50%*	1,240.1	*30%*
Natural Gas	312.5	*35%*	447.0	*42%*	685.4	*18%*	1,380.3	*34%*
Combined Cycle (CC)	106.1	*12%*	239.5	*23%*	387.7	*10%*	1,152.0	*28%*
Combustion Turbine (CT)	103.4	*12%*	131.0	*12%*	98.8	*3%*	129.6	*3%*
Steam Turbine (ST)	103.0	*12%*	76.4	*7%*	198.9	*5%*	98.6	*2%*
Nuclear	98.7	*11%*	99.3	*9%*	780.1	*20%*	805.3	*20%*
Hydro	79.4	*9%*	80.0	*8%*	264.3	*7%*	265.8	*7%*
Wind	4.4	*0%*	81.3	*8%*	10.4	*0%*	226.9	*6%*
Oil	59.7	*7%*	36.4	*3%*	94.5	*2%*	23.9	*1%*
Solar	0.4	*0%*	21.5	*2%*	0.6	*0%*	36.8	*1%*
Other	14.6	*2%*	21.2	*2%*	92.5	*2%*	106.7	*3%*
Total	**884.9**	*100%*	**1,056.7**	*100%*	**3,860.9**	*100%*	**4,085.8**	*100%*

New England Regional Profile

Energy Sources
- Coal
- Natural Gas (CC)
- Natural Gas (CT)
- Natural Gas (ST)
- Nuclear
- Hydro
- Wind
- Oil
- Solar
- Other

Notes:
Capacity values are summer capacity. Data for utility-scale resources only (1+ MW nameplate capacity). Natural gas technologies: CC = combined cycle, CT = combustion turbine, ST = steam turbine. Ownership type: VIEU = vertically integrated electric utility. Map includes 2017 Q1 actual and Q2-4 announced retirements. Prices: Natural gas = Algon. Gates, Coal = Central App., Electricity = ISO-NE Mass Hub. *Total % Capacity Reduction calculation: retired capacity / (retired capacity + 2016 operational capacity)



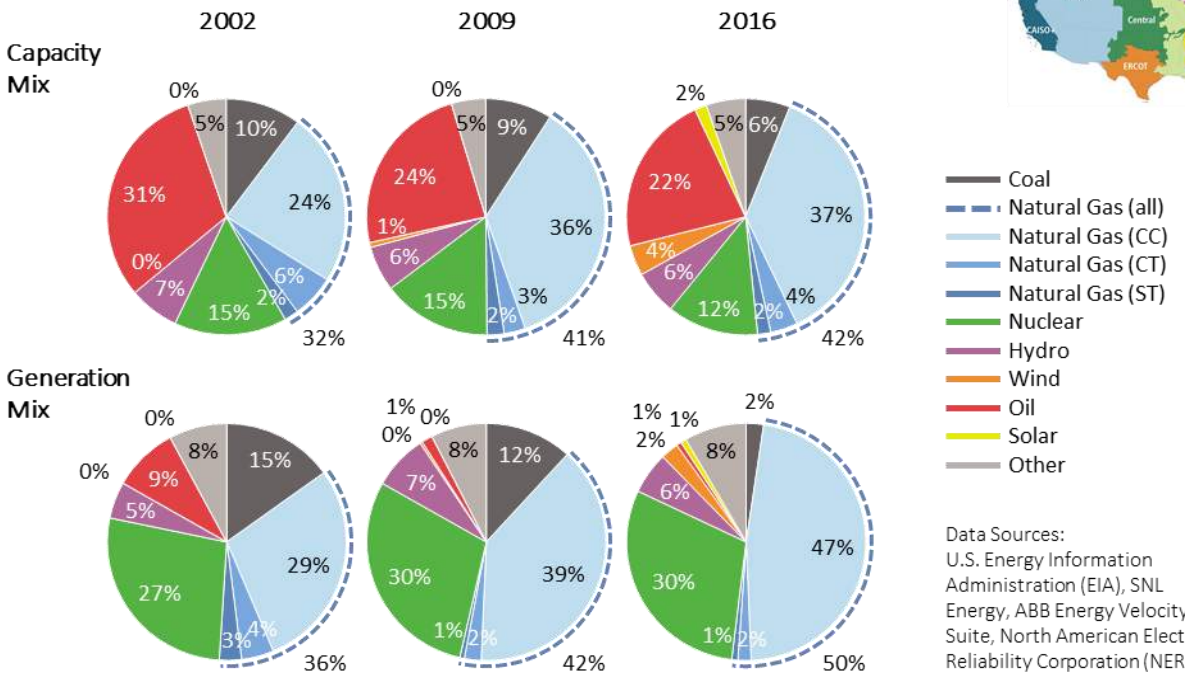


Total Capacity & Generation	2002	2016
Capacity (MW)	28,338	32,303
Generation (GWh)	124,613	108,802

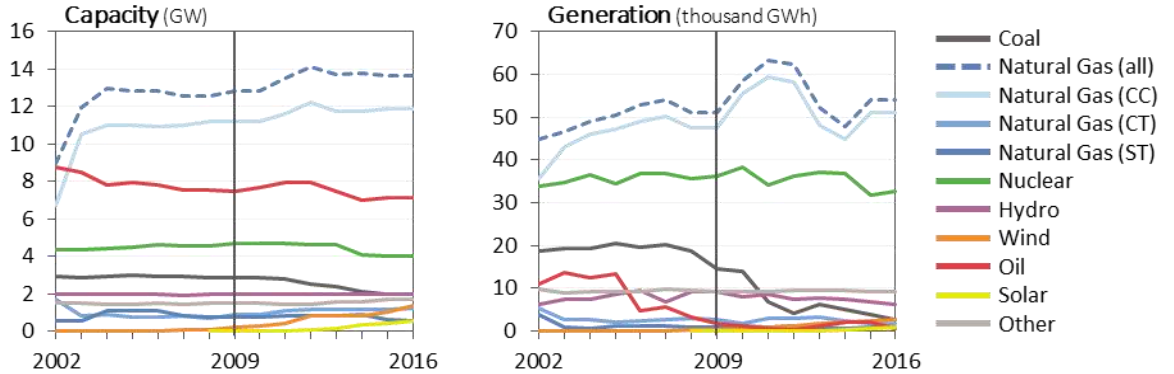
Retirements by Energy Source, 2002-2016	# of Generators	MW
Coal	7	784
Natural Gas	14	837
Nuclear	1	612
Oil	74	1,808
Hydro	50	27
Other (all other sources)	45	140
*Total % Cap. Reduction**	*11.5%*	4,209

NERC Reserve Margin, 2017 (2016 LTRA)	Target	Actual
NPCC-New England	16.74%	20.32%

New England Regional Profile



Data Sources:
U.S. Energy Information Administration (EIA), SNL Energy, ABB Energy Velocity Suite, North American Electric Reliability Corporation (NERC)



Capacity & Generation by Energy Source, 2002 & 2016

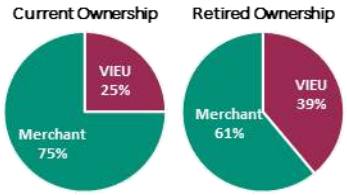
Energy Source	Capacity 2002 GW	Capacity 2002 %	Capacity 2016 GW	Capacity 2016 %	Generation 2002 thous. GWh	Generation 2002 %	Generation 2016 thous. GWh	Generation 2016 %
Coal	2.9	*10%*	2.0	*6%*	18.8	*15%*	2.6	*2%*
Natural Gas	8.9	*32%*	13.7	*42%*	44.8	*36%*	54.0	*50%*
Combined Cycle (CC)	6.7	*24%*	11.9	*37%*	35.6	*29%*	51.1	*47%*
Combustion Turbine (CT)	1.7	*6%*	1.2	*4%*	5.4	*4%*	1.9	*2%*
Steam Turbine (ST)	0.6	*2%*	0.6	*2%*	3.7	*3%*	0.9	*1%*
Nuclear	4.3	*15%*	4.0	*12%*	33.9	*27%*	32.8	*30%*
Hydro	1.9	*7%*	2.0	*6%*	6.2	*5%*	6.2	*6%*
Wind	0.0	*0%*	1.3	*4%*	0.0	*0%*	2.6	*2%*
Oil	8.7	*31%*	7.1	*22%*	11.1	*9%*	0.7	*1%*
Solar	0.0	*0%*	0.5	*2%*	0.0	*0%*	0.8	*1%*
Other	1.5	*5%*	1.7	*5%*	9.8	*8%*	9.1	*8%*
Total	**28.3**	*100%*	**32.3**	*100%*	**124.6**	*100%*	**108.8**	*100%*

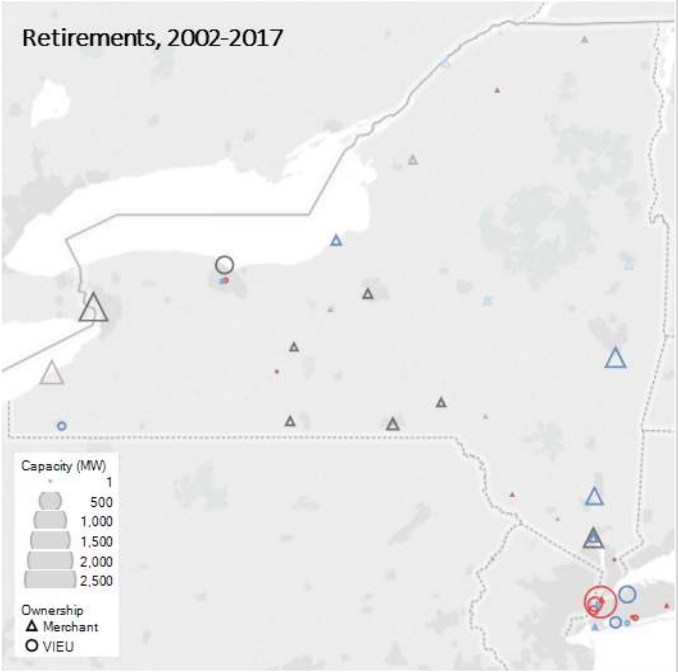
New York Regional Profile

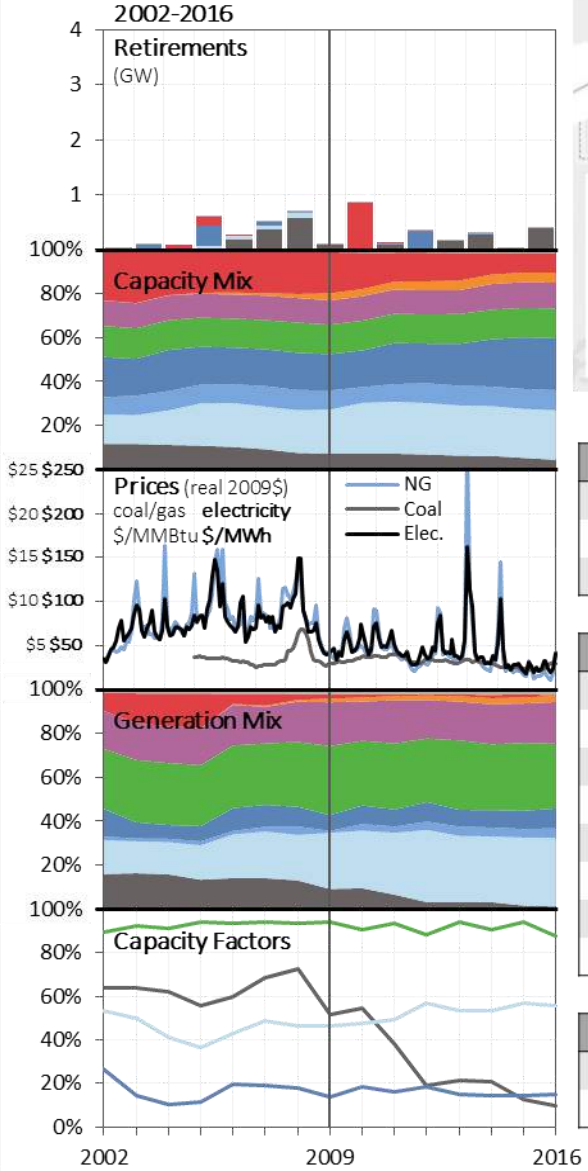
Energy Sources

- Coal
- Natural Gas (CC)
- Natural Gas (CT)
- Natural Gas (ST)
- Nuclear
- Hydro
- Wind
- Oil
- Solar
- Other

Notes:
Capacity values are summer capacity. Data for utility-scale resources only (1+ MW nameplate capacity). Natural gas technologies: CC = combined cycle, CT = combustion turbine, ST = steam turbine. Ownership type: VIEU = vertically integrated electric utility. Map includes 2017 Q1 actual and Q2-4 announced retirements. Prices: Natural gas = Transco Z6 NY, Coal = Central App., Electricity = NYISO NYC Zone J. *Total % Capacity Reduction calculation: retired capacity / (retired capacity + 2016 operational capacity)





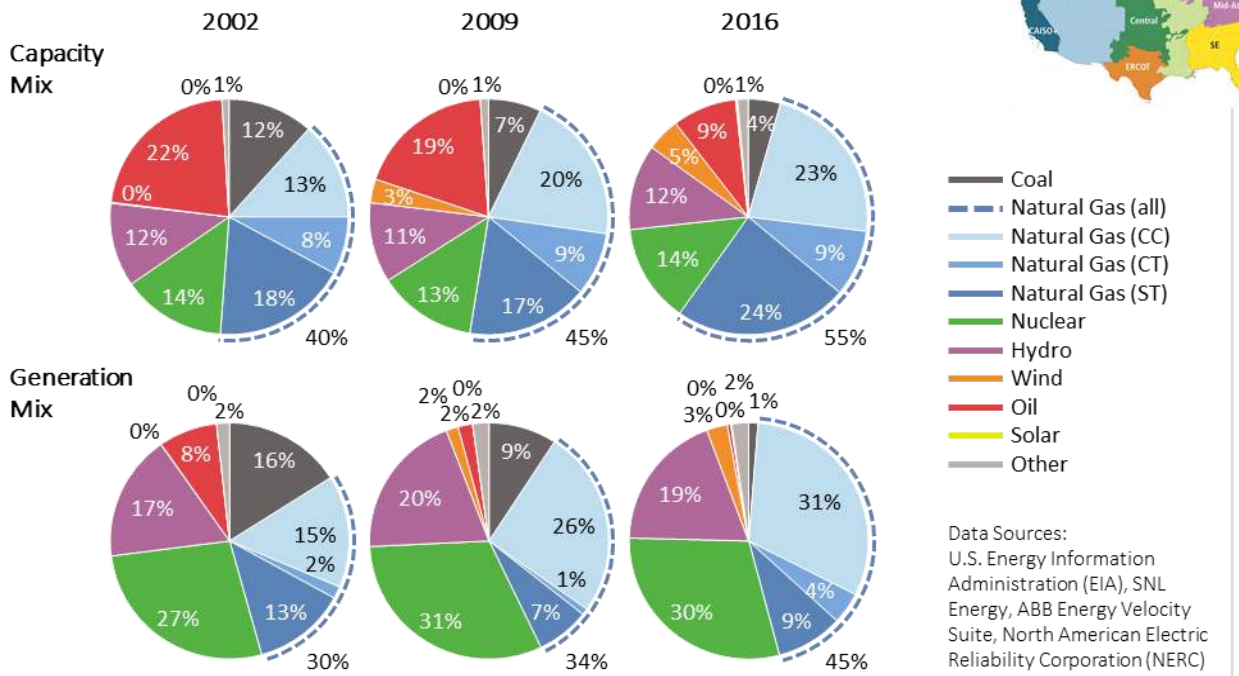


Total Capacity & Generation	2002	2016
Capacity (MW)	35,642	39,975
Generation (GWh)	145,126	140,728

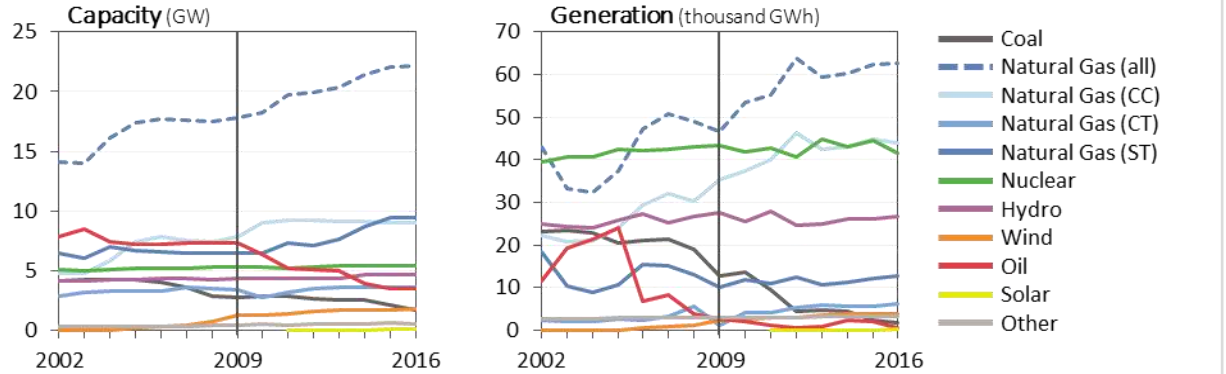
Retirements by Energy Source, 2002-2016	# of Generators	MW
Coal	26	2,129
Natural Gas	37	1,202
Nuclear	0	0
Oil	17	1,139
Hydro	13	15
Other (all other sources)	24	45
*Total % Cap. Reduction**	*10.2%*	**4,529**

NERC Reserve Margin, 2017 (2016 LTRA)	Target	Actual
NPCC-New York	15.00%	23.35%

New York Regional Profile



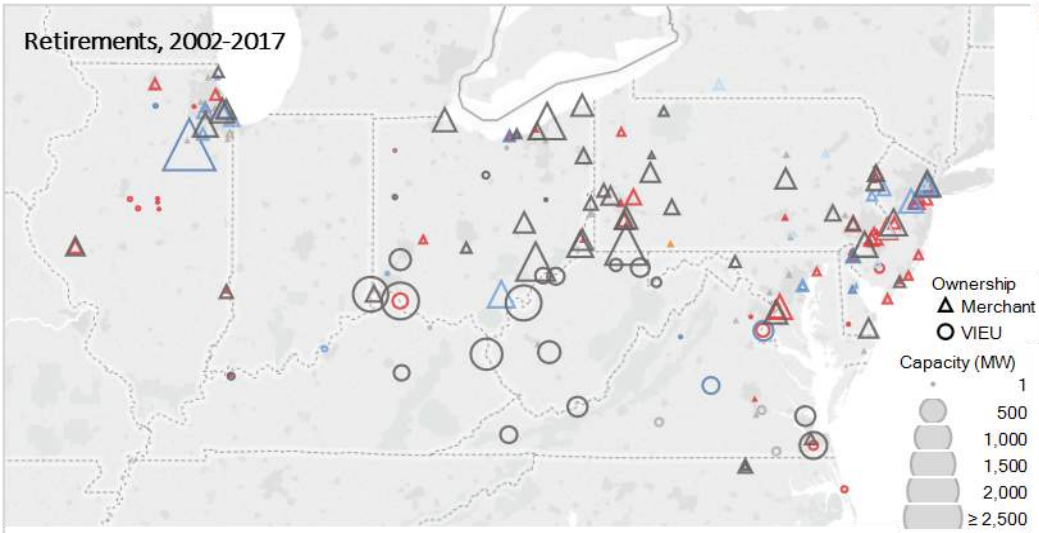
Data Sources:
U.S. Energy Information Administration (EIA), SNL Energy, ABB Energy Velocity Suite, North American Electric Reliability Corporation (NERC)

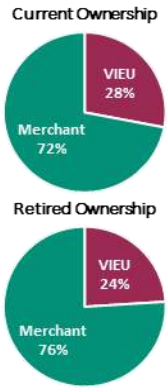


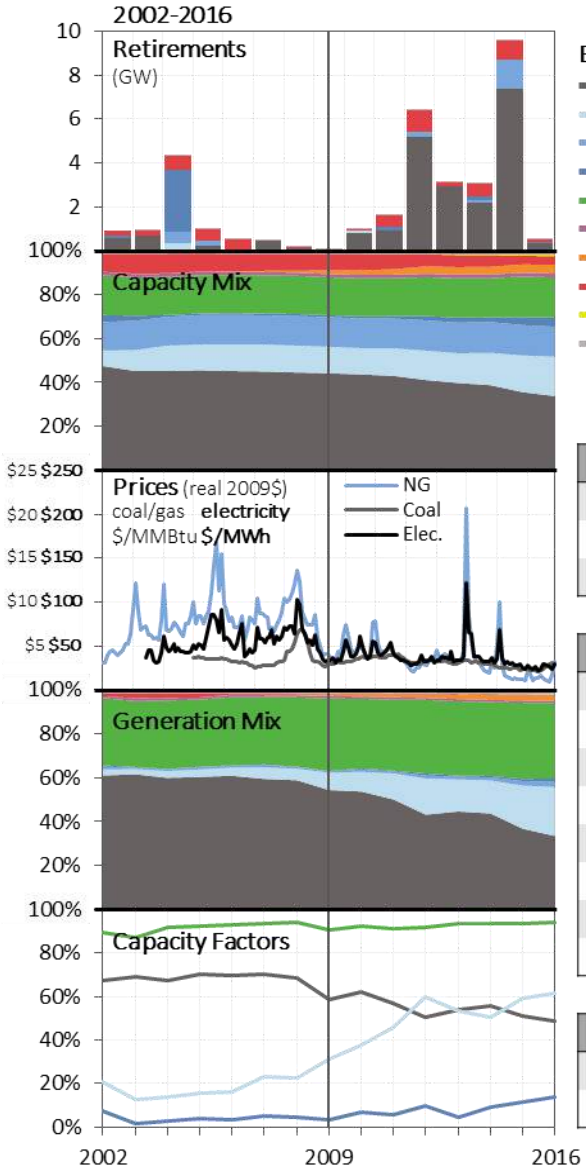
Capacity & Generation by Energy Source, 2002 & 2016

Energy Source	Capacity 2002 GW	Capacity 2002 %	Capacity 2016 GW	Capacity 2016 %	Generation 2002 thous. GWh	Generation 2002 %	Generation 2016 thous. GWh	Generation 2016 %
Coal	4.1	*12%*	1.7	*4%*	23.2	*16%*	1.8	*1%*
Natural Gas	14.1	*40%*	22.1	*55%*	43.0	*30%*	62.8	*45%*
Combined Cycle (CC)	4.8	*13%*	9.0	*23%*	22.3	*15%*	43.9	*31%*
Combustion Turbine (CT)	2.8	*8%*	3.7	*9%*	2.4	*2%*	6.1	*4%*
Steam Turbine (ST)	6.5	*18%*	9.5	*24%*	18.3	*13%*	12.7	*9%*
Nuclear	5.0	*14%*	5.4	*14%*	39.6	*27%*	41.6	*30%*
Hydro	4.1	*12%*	4.7	*12%*	25.0	*17%*	26.6	*19%*
Wind	0.0	*0%*	1.8	*5%*	0.1	*0%*	3.9	*3%*
Oil	7.9	*22%*	3.5	*9%*	11.6	*8%*	0.7	*0%*
Solar	0.0	*0%*	0.1	*0%*	0.0	*0%*	0.2	*0%*
Other	0.3	*1%*	0.6	*1%*	2.5	*2%*	3.2	*2%*
Total	**35.6**	*100%*	**40.0**	*100%*	**145.1**	*100%*	**140.7**	*100%*

Mid-Atlantic Regional Profile







Energy Sources

- Coal
- Natural Gas (CC)
- Natural Gas (CT)
- Natural Gas (ST)
- Nuclear
- Hydro
- Wind
- Oil
- Solar
- Other

Notes:
Capacity values are summer capacity. Data for utility-scale resources only (1+ MW nameplate capacity). Natural gas technologies: CC = combined cycle, CT = combustion turbine, ST = steam turbine. Ownership type: VIEU = vertically integrated electric utility. Map includes 2017 Q1 actual and Q2-4 announced retirements. Prices: Natural gas = TETCO M3, Coal = Central App., Electricity = PJM Western Hub.
*Total % Capacity Reduction calculation: retired capacity / (retired capacity + 2016 operational capacity)

Total Capacity & Generation

	2002	2016
Capacity (MW)	180,697	186,759
Generation (GWh)	833,011	810,922

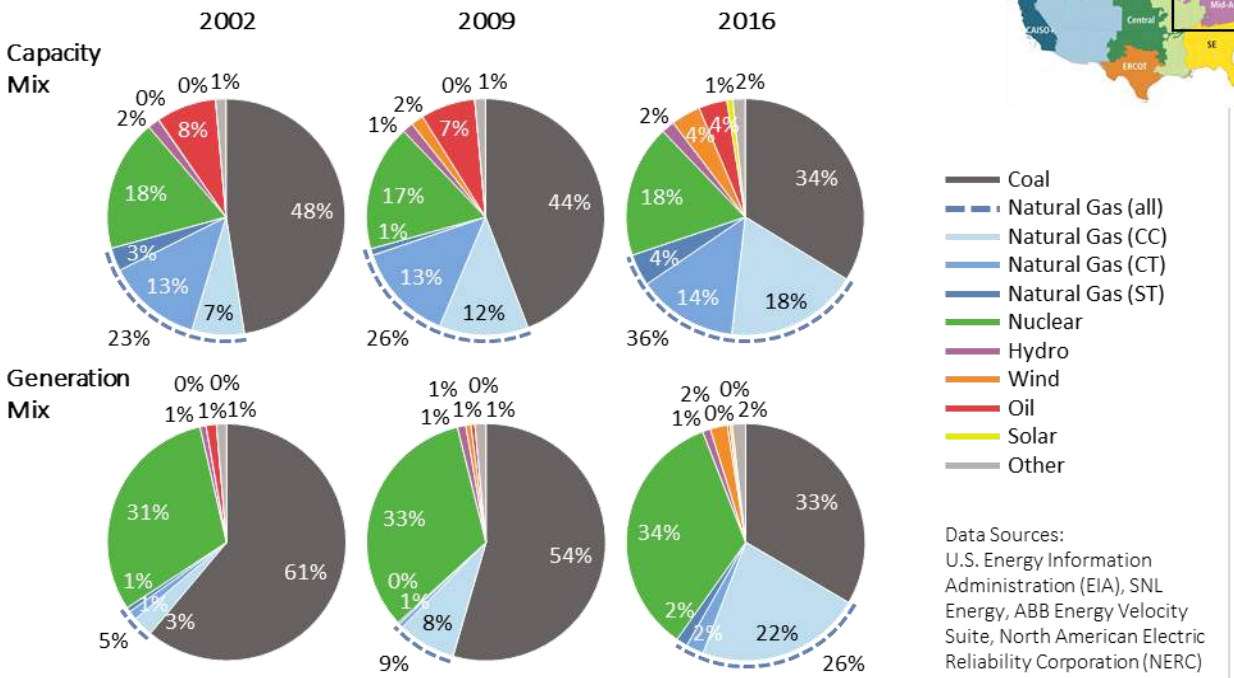
Retirements by Energy Source, 2002-2016

	# of Generators	MW
Coal	163	21,791
Natural Gas	152	6,315
Nuclear	0	0
Oil	173	5,326
Hydro	3	2
Other (all other sources)	95	224
*Total % Cap. Reduction**	*15.3%*	33,657

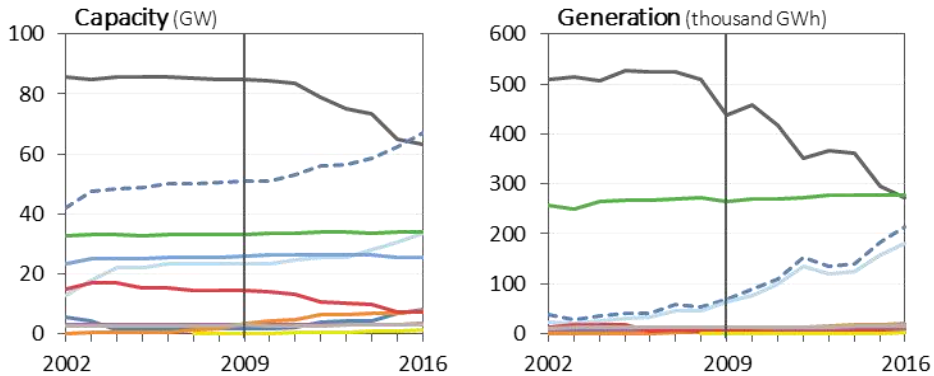
NERC Reserve Margin, 2017 (2016 LTRA)

	Target	Actual
PJM	16.50%	31.11%

Mid-Atlantic Regional Profile



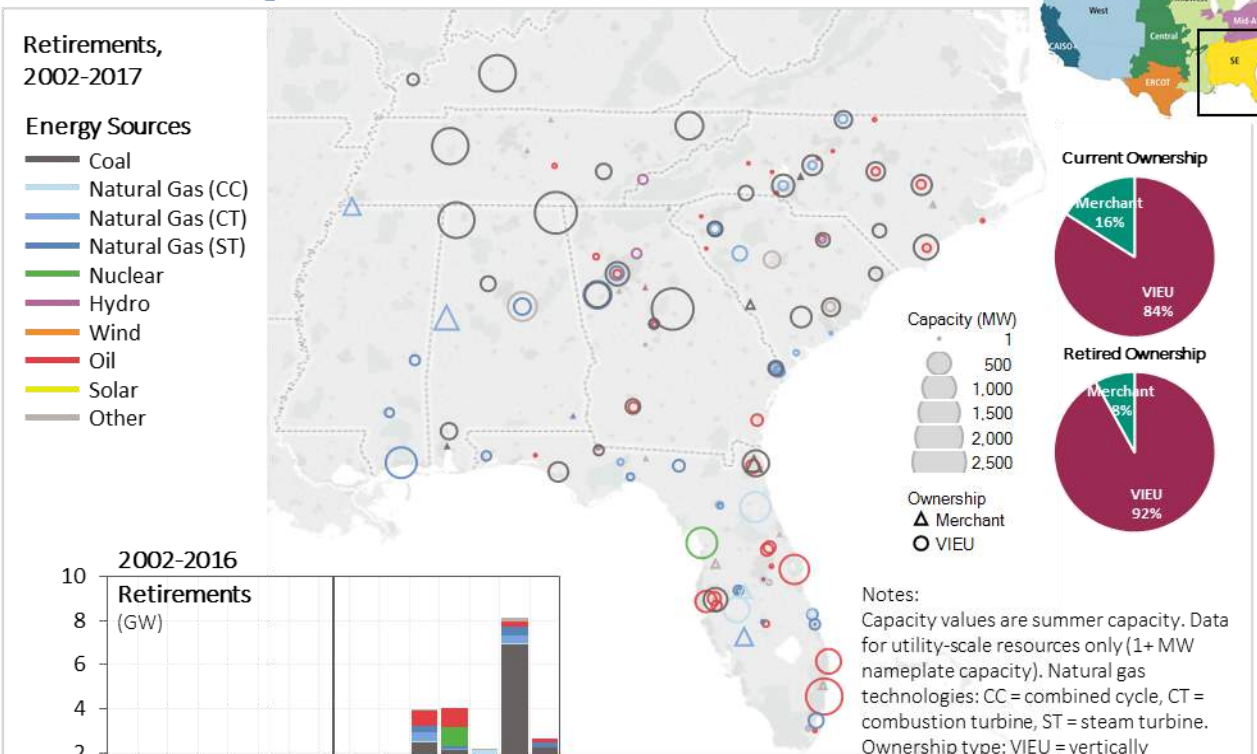
Data Sources:
U.S. Energy Information Administration (EIA), SNL Energy, ABB Energy Velocity Suite, North American Electric Reliability Corporation (NERC)

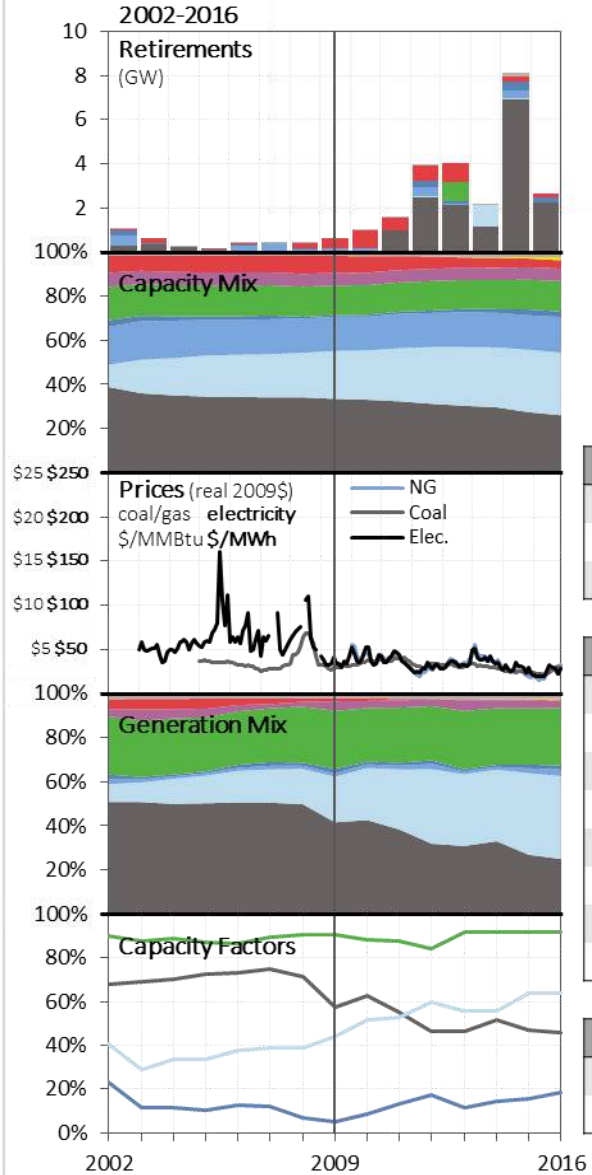


Capacity & Generation by Energy Source, 2002 & 2016

Energy Source	Capacity 2002 GW	Capacity 2002 %	Capacity 2016 GW	Capacity 2016 %	Generation 2002 thous. GWh	Generation 2002 %	Generation 2016 thous. GWh	Generation 2016 %
Coal	85.9	*48%*	63.1	*34%*	508.5	*61%*	271.6	*33%*
Natural Gas	41.9	*23%*	67.2	*36%*	38.7	*5%*	212.9	*26%*
Combined Cycle (CC)	12.8	*7%*	33.6	*18%*	23.3	*3%*	181.1	*22%*
Combustion Turbine (CT)	23.3	*13%*	25.4	*14%*	10.1	*1%*	19.4	*2%*
Steam Turbine (ST)	5.7	*3%*	8.1	*4%*	5.3	*1%*	12.4	*2%*
Nuclear	32.6	*18%*	33.8	*18%*	255.9	*31%*	278.8	*34%*
Hydro	2.9	*2%*	3.3	*2%*	6.8	*1%*	8.7	*1%*
Wind	0.1	*0%*	7.5	*4%*	0.1	*0%*	18.9	*2%*
Oil	14.8	*8%*	7.2	*4%*	11.7	*1%*	2.7	*0%*
Solar	0.0	*0%*	1.5	*1%*	0.0	*0%*	2.5	*0%*
Other	2.6	*1%*	3.1	*2%*	11.3	*1%*	14.7	*2%*
Total	**180.7**	*100%*	**186.8**	*100%*	**833.0**	*100%*	**810.9**	*100%*

Southeast Regional Profile





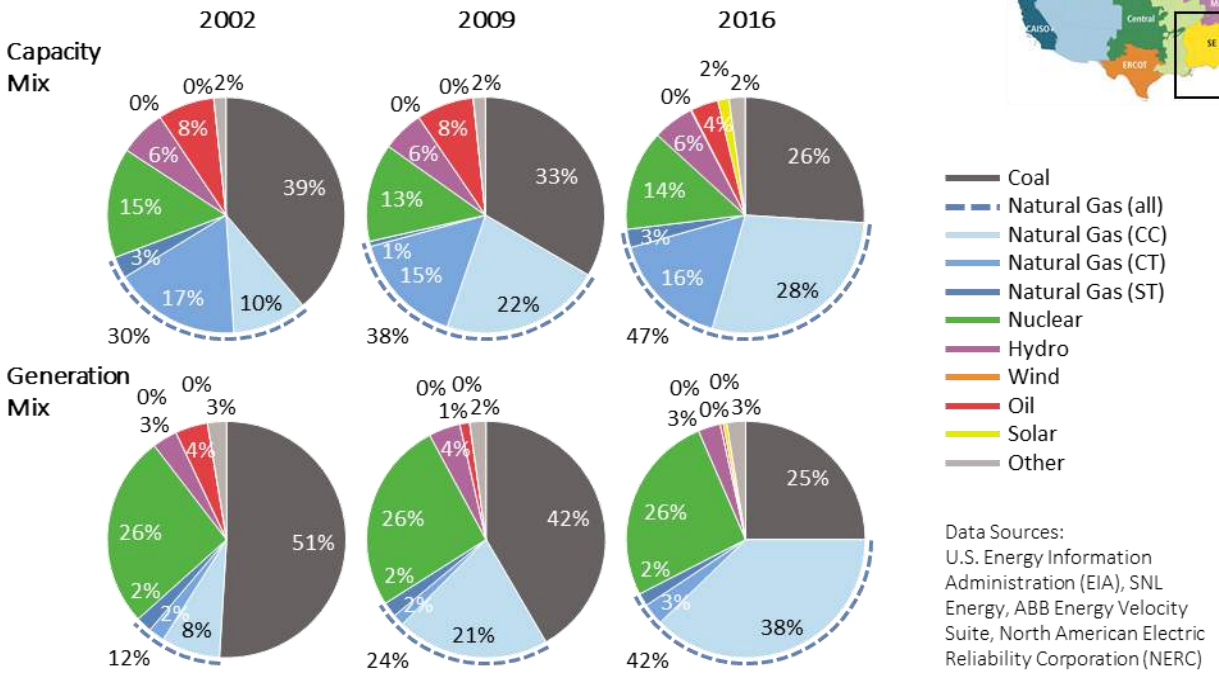
Notes:
Capacity values are summer capacity. Data for utility-scale resources only (1+ MW nameplate capacity). Natural gas technologies: CC = combined cycle, CT = combustion turbine, ST = steam turbine. Ownership type: VIEU = vertically integrated electric utility. Map includes 2017 Q1 actual and Q2-4 announced retirements. Prices: Natural gas = Transco Z4, Coal = Central App., Electricity = Into Southern.
*Total % Capacity Reduction calculation: retired capacity / (retired capacity + 2016 operational capacity)

Total Capacity & Generation	2002	2016
Capacity (MW)	181,536	209,753
Generation (GWh)	824,381	886,610

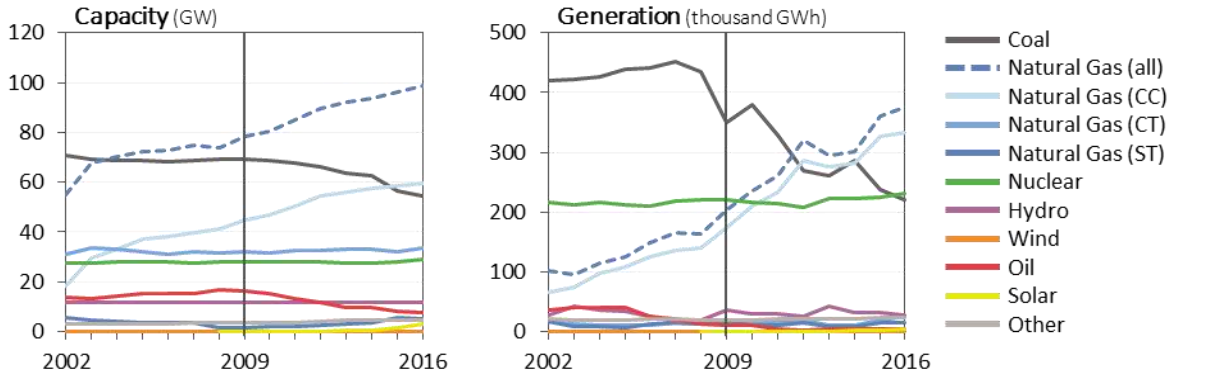
Retirements by Energy Source, 2002-2016	# of Generators	MW
Coal	120	16,588
Natural Gas	126	5,140
Nuclear	1	860
Oil	100	4,371
Hydro	6	3
Other (all other sources)	22	206
*Total % Cap. Reduction**	*11.5%*	27,169

NERC Reserve Margin, 2017 (2016 LTRA)	Target	Actual
SERC/FRCC	15.00%	20.02-31.91%

Southeast Regional Profile



Data Sources:
U.S. Energy Information Administration (EIA), SNL Energy, ABB Energy Velocity Suite, North American Electric Reliability Corporation (NERC)



Capacity & Generation by Energy Source, 2002 & 2016

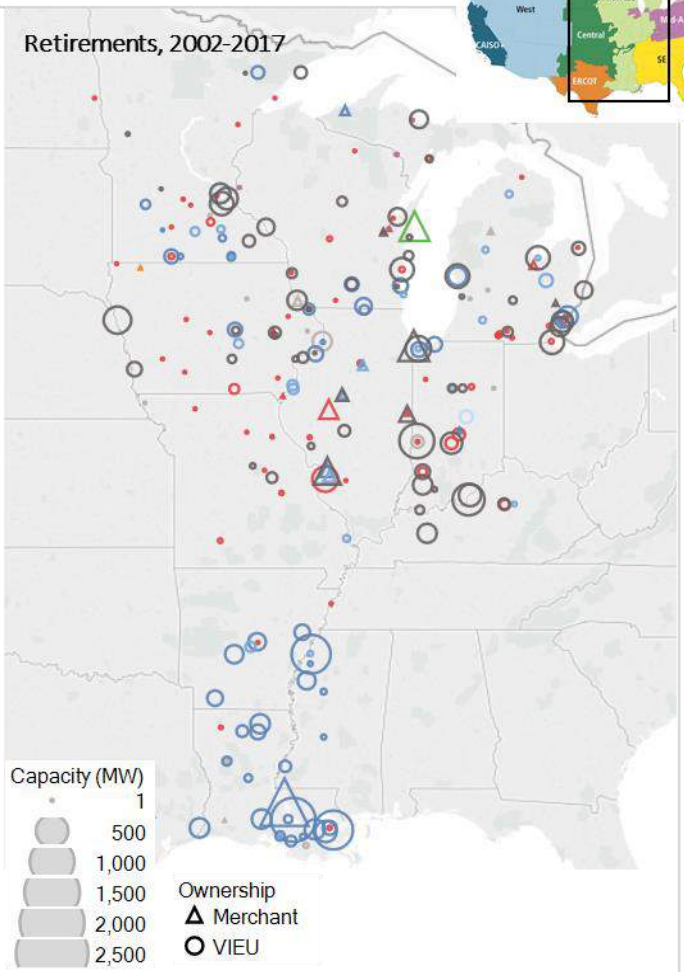
Energy Source	Capacity 2002 GW	Capacity 2002 %	Capacity 2016 GW	Capacity 2016 %	Generation 2002 thous. GWh	Generation 2002 %	Generation 2016 thous. GWh	Generation 2016 %
Coal	70.5	*39%*	54.6	*26%*	420.1	*51%*	221.7	*25%*
Natural Gas	55.0	*30%*	98.7	*47%*	101.6	*12%*	375.8	*42%*
Combined Cycle (CC)	18.4	*10%*	59.6	*28%*	65.9	*8%*	334.0	*38%*
Combustion Turbine (CT)	31.2	*17%*	33.8	*16%*	18.0	*2%*	26.2	*3%*
Steam Turbine (ST)	5.4	*3%*	5.3	*3%*	17.8	*2%*	15.6	*2%*
Nuclear	27.5	*15%*	28.9	*14%*	217.2	*26%*	231.9	*26%*
Hydro	11.6	*6%*	11.7	*6%*	28.0	*3%*	26.9	*3%*
Wind	0.0	*0%*	0.2	*0%*	0.0	*0%*	0.0	*0%*
Oil	14.0	*8%*	7.9	*4%*	36.3	*4%*	3.6	*0%*
Solar	0.0	*0%*	3.2	*2%*	0.0	*0%*	4.3	*0%*
Other	3.0	*2%*	4.6	*2%*	21.2	*3%*	22.4	*3%*
Total	**181.5**	*100%*	**209.8**	*100%*	**824.4**	*100%*	**886.6**	*100%*

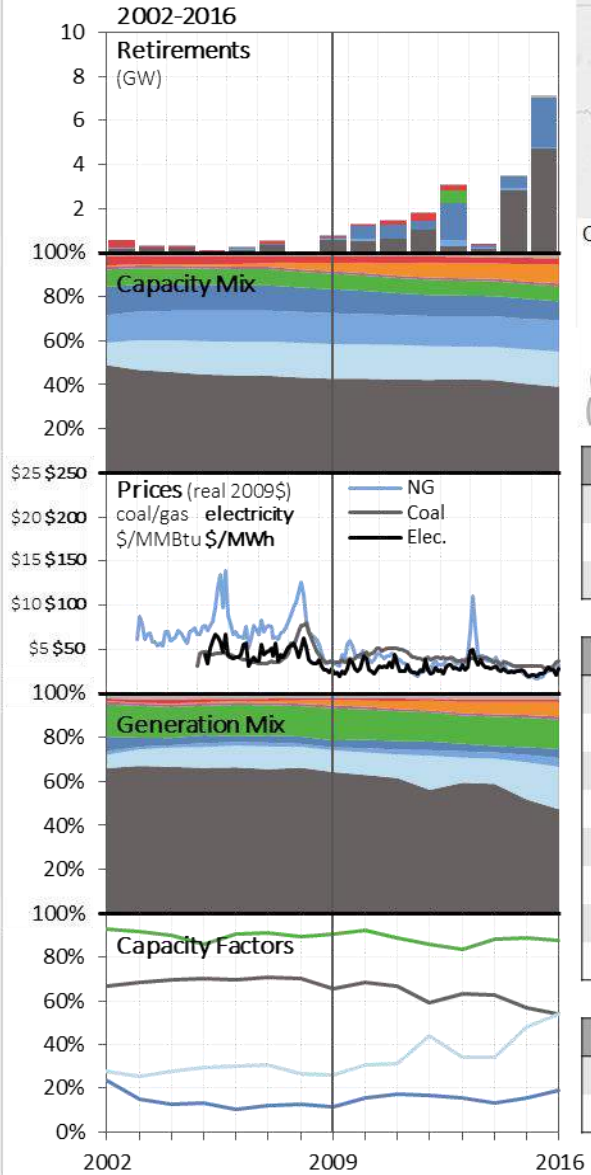
Midwest Regional Profile

Energy Sources

- Coal
- Natural Gas (CC)
- Natural Gas (CT)
- Natural Gas (ST)
- Nuclear
- Hydro
- Wind
- Oil
- Solar
- Other

Notes:
Capacity values are summer capacity. Data for utility-scale resources only (1+ MW nameplate capacity). Natural gas technologies: CC = combined cycle, CT = combustion turbine, ST = steam turbine. Ownership type: VIEU = vertically integrated electric utility. Map includes 2017 Q1 actual and Q2-4 announced retirements. Prices: Natural gas = Chicago, Coal = Powder River Basin, Electricity = MISO Illinois Hub. *Total % Capacity Reduction calculation: retired capacity / (retired capacity + 2016 operational capacity)



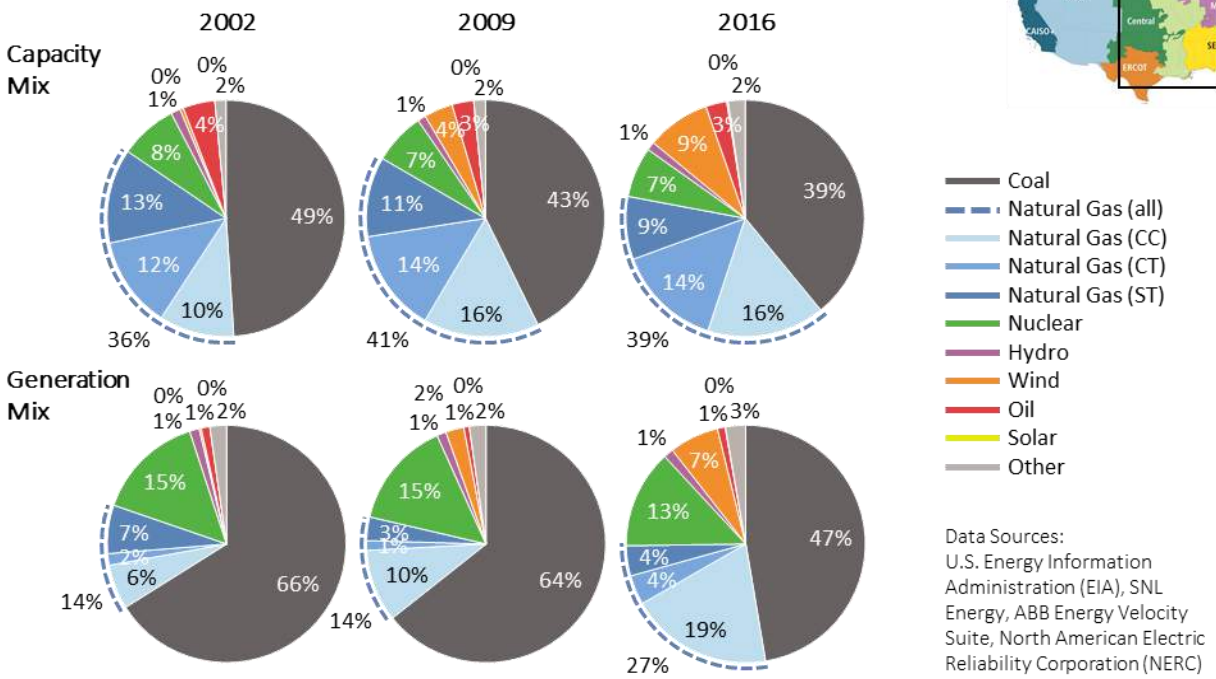


Total Capacity & Generation	2002	2016
Capacity (MW)	163,917	187,957
Generation (GWh)	710,131	744,323

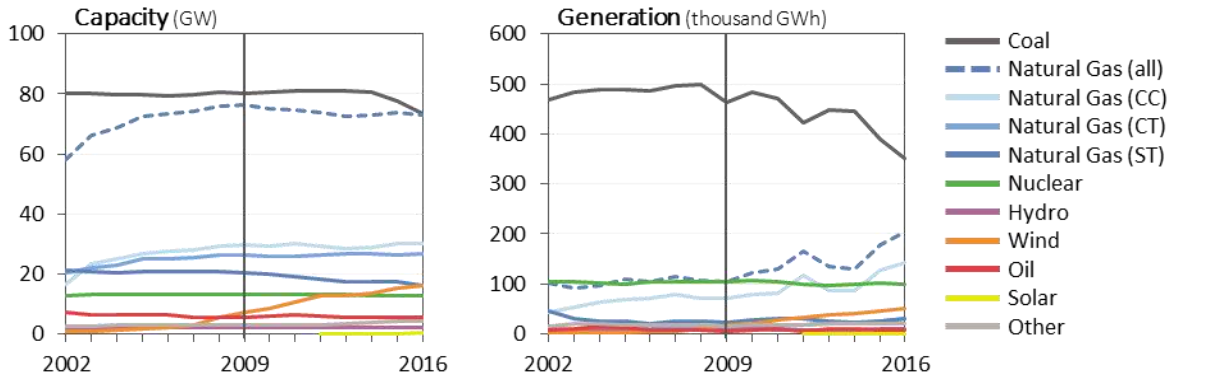
Retirements by Energy Source, 2002-2016	# of Generators	MW
Coal	151	11,815
Natural Gas	178	7,277
Nuclear	1	566
Oil	323	1,412
Hydro	17	15
Other (all other sources)	56	213
*Total % Cap. Reduction**	*10.2%*	**21,297**

NERC Reserve Margin, 2017 (2016 LTRA)	Target	Actual
MISO	15.20%	18.09%

Midwest Regional Profile



Data Sources:
U.S. Energy Information Administration (EIA), SNL Energy, ABB Energy Velocity Suite, North American Electric Reliability Corporation (NERC)



Capacity & Generation by Energy Source, 2002 & 2016

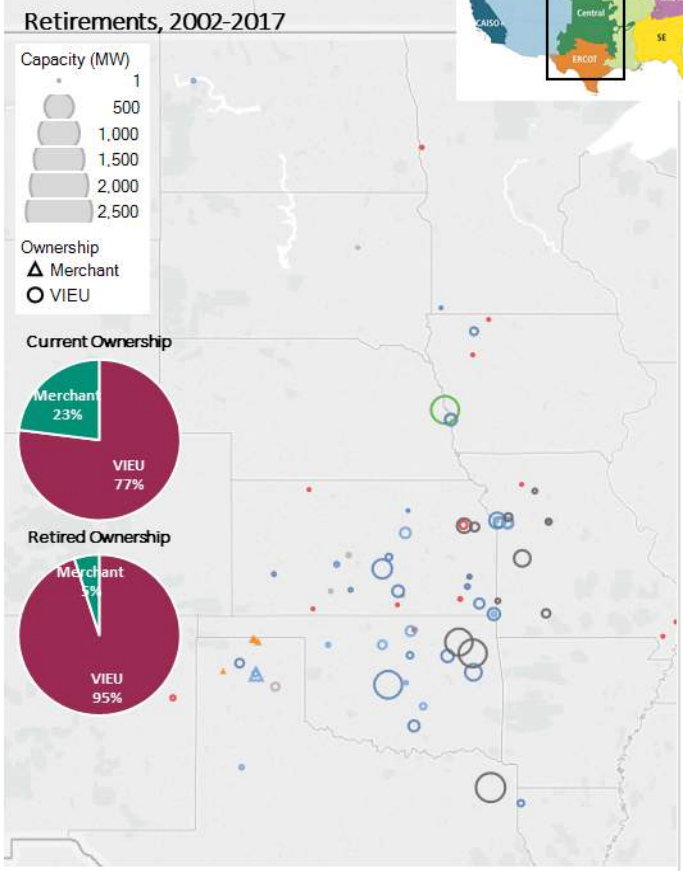
Energy Source	Capacity 2002 GW	%	Capacity 2016 GW	%	Generation 2002 thous. GWh	%	Generation 2016 thous. GWh	%
Coal	80.3	*49%*	73.5	*39%*	469.0	*66%*	352.5	*47%*
Natural Gas	58.3	*36%*	73.1	*39%*	101.2	*14%*	204.0	*27%*
Combined Cycle (CC)	16.7	*10%*	30.0	*16%*	43.0	*6%*	143.7	*19%*
Combustion Turbine (CT)	20.5	*12%*	26.9	*14%*	11.3	*2%*	29.8	*4%*
Steam Turbine (ST)	21.2	*13%*	16.1	*9%*	46.9	*7%*	30.5	*4%*
Nuclear	12.8	*8%*	12.9	*7%*	104.3	*15%*	99.7	*13%*
Hydro	2.1	*1%*	2.2	*1%*	9.3	*1%*	9.9	*1%*
Wind	0.8	*0%*	16.3	*9%*	1.9	*0%*	49.8	*7%*
Oil	7.1	*4%*	5.4	*3%*	8.4	*1%*	7.9	*1%*
Solar	0.0	*0%*	0.3	*0%*	0.0	*0%*	0.3	*0%*
Other	2.5	*2%*	4.3	*2%*	16.0	*2%*	20.2	*3%*
Total	**163.9**	*100%*	**188.0**	*100%*	**710.1**	*100%*	**744.3**	*100%*

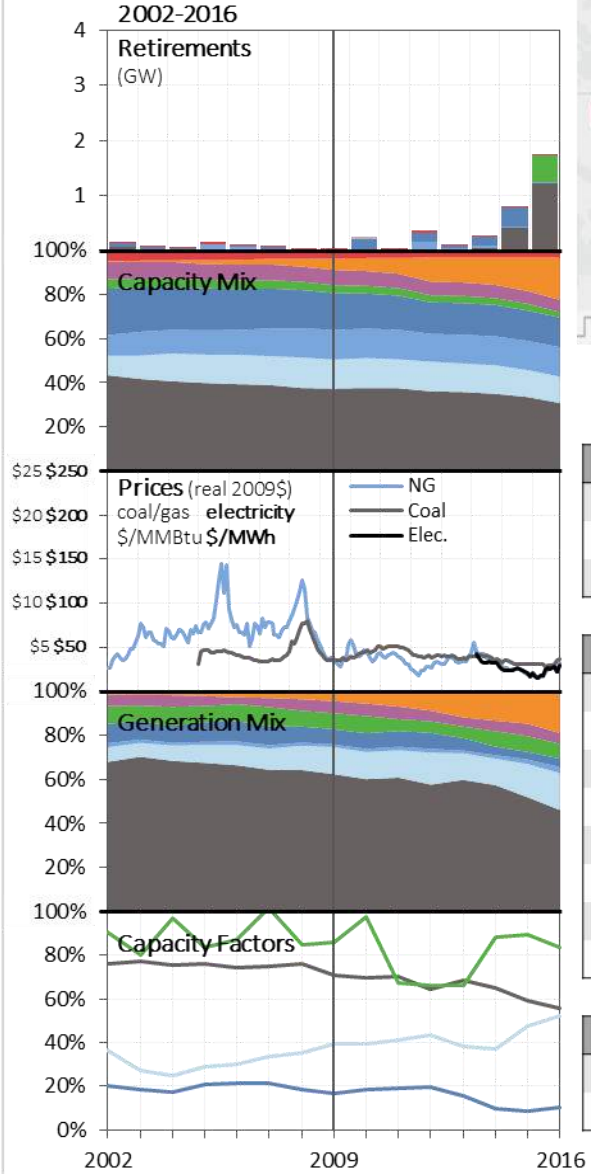
Central Regional Profile

Energy Sources

- Coal
- Natural Gas (CC)
- Natural Gas (CT)
- Natural Gas (ST)
- Nuclear
- Hydro
- Wind
- Oil
- Solar
- Other

Notes:
Capacity values are summer capacity. Data for utility-scale resources only (1+ MW nameplate capacity). Natural gas technologies: CC = combined cycle, CT = combustion turbine, ST = steam turbine. Ownership type: VIEU = vertically integrated electric utility. Map includes 2017 Q1 actual and Q2-4 announced retirements. Prices: Natural gas = Henry Hub, Coal = Powder River Basin, Electricity = SPP South Hub. *Total % Capacity Reduction calculation: retired capacity / (retired capacity + 2016 operational capacity)



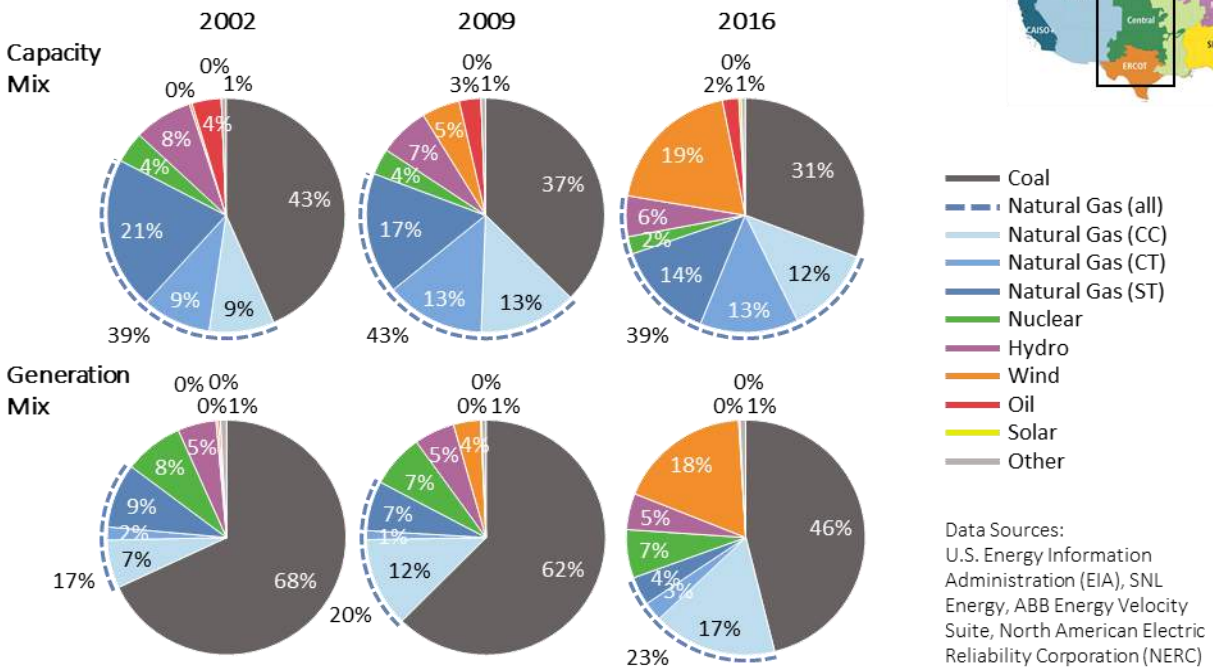


Total Capacity & Generation	2002	2016
Capacity (MW)	55,948	80,672
Generation (GWh)	237,790	264,354

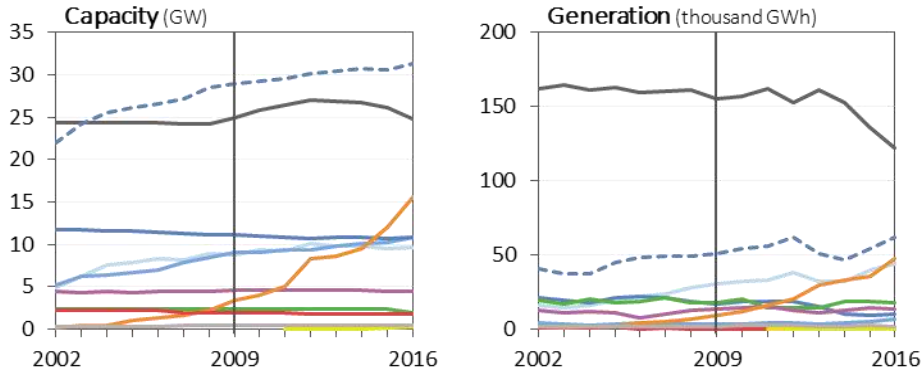
Retirements by Energy Source, 2002-2016	# of Generators	MW
Coal	22	1,749
Natural Gas	107	1,678
Nuclear	1	478
Oil	149	218
Hydro	0	0
Other (all other sources)	7	44
*Total % Cap. Reduction**	***4.9%***	**4,167**

NERC Reserve Margin, 2017 (2016 LTRA)	Target	Actual
SPP	12.00%	27.16%

Central Regional Profile



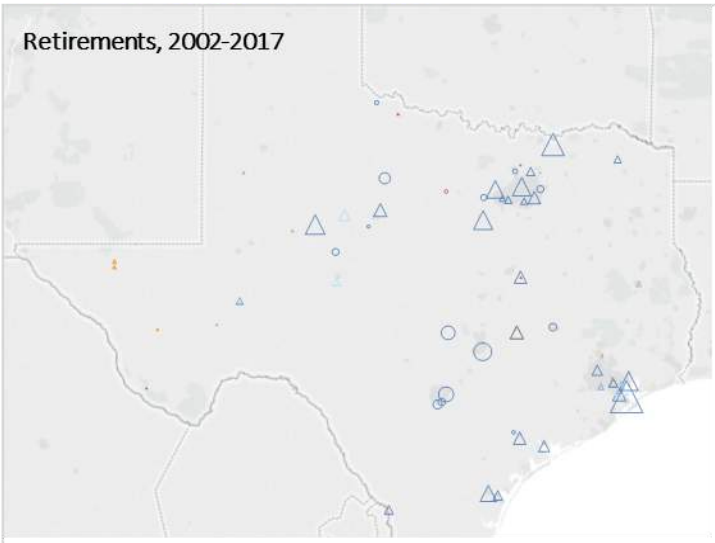
Data Sources:
U.S. Energy Information Administration (EIA), SNL Energy, ABB Energy Velocity Suite, North American Electric Reliability Corporation (NERC)

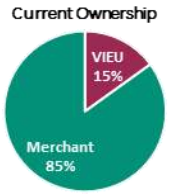


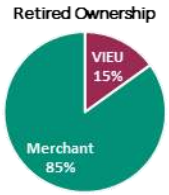
Capacity & Generation by Energy Source, 2002 & 2016

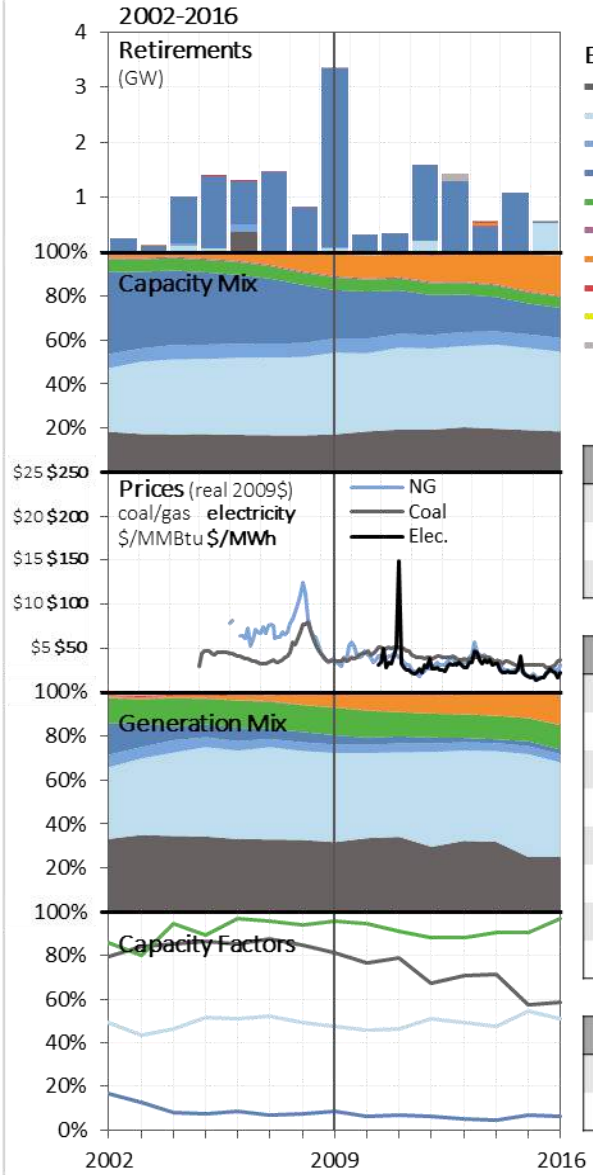
Energy Source	Capacity 2002 GW	%	Capacity 2016 GW	%	Generation 2002 thous. GWh	%	Generation 2016 thous. GWh	%
Coal	24.3	*43%*	24.8	*31%*	161.7	*68%*	121.9	*46%*
Natural Gas	22.0	*39%*	31.4	*39%*	41.1	*17%*	61.7	*23%*
Combined Cycle (CC)	4.9	*9%*	9.7	*12%*	15.8	*7%*	44.3	*17%*
Combustion Turbine (CT)	5.3	*9%*	10.8	*13%*	4.3	*2%*	6.9	*3%*
Steam Turbine (ST)	11.8	*21%*	10.9	*14%*	21.1	*9%*	10.4	*4%*
Nuclear	2.4	*4%*	1.9	*2%*	19.2	*8%*	17.6	*7%*
Hydro	4.5	*8%*	4.5	*6%*	12.4	*5%*	13.2	*5%*
Wind	0.2	*0%*	15.5	*19%*	0.7	*0%*	47.5	*18%*
Oil	2.2	*4%*	1.8	*2%*	0.7	*0%*	0.1	*0%*
Solar	0.0	*0%*	0.3	*0%*	0.0	*0%*	0.3	*0%*
Other	0.4	*1%*	0.4	*1%*	1.9	*1%*	2.1	*1%*
Total	**55.9**	*100%*	**80.7**	*100%*	**237.8**	*100%*	**264.4**	*100%*

ERCOT Regional Profile









Energy Sources

- Coal
- Natural Gas (CC)
- Natural Gas (CT)
- Natural Gas (ST)
- Nuclear
- Hydro
- Wind
- Oil
- Solar
- Other

Notes:
Capacity values are summer capacity. Data for utility-scale resources only (1+ MW nameplate capacity). Natural gas technologies: CC = combined cycle, CT = combustion turbine, ST = steam turbine. Ownership type: VIEU = vertically integrated electric utility. Map includes 2017 Q1 actual and Q2-4 announced retirements. Prices: Natural gas = Houston Ship Channel, Coal = Powder River Basin, Electricity = ERCOT North Hub.
*Total % Capacity Reduction calculation: retired capacity / (retired capacity + 2016 operational capacity)

Total Capacity & Generation

	2002	2016
Capacity (MW)	80,762	101,310
Generation (GWh)	312,059	382,003

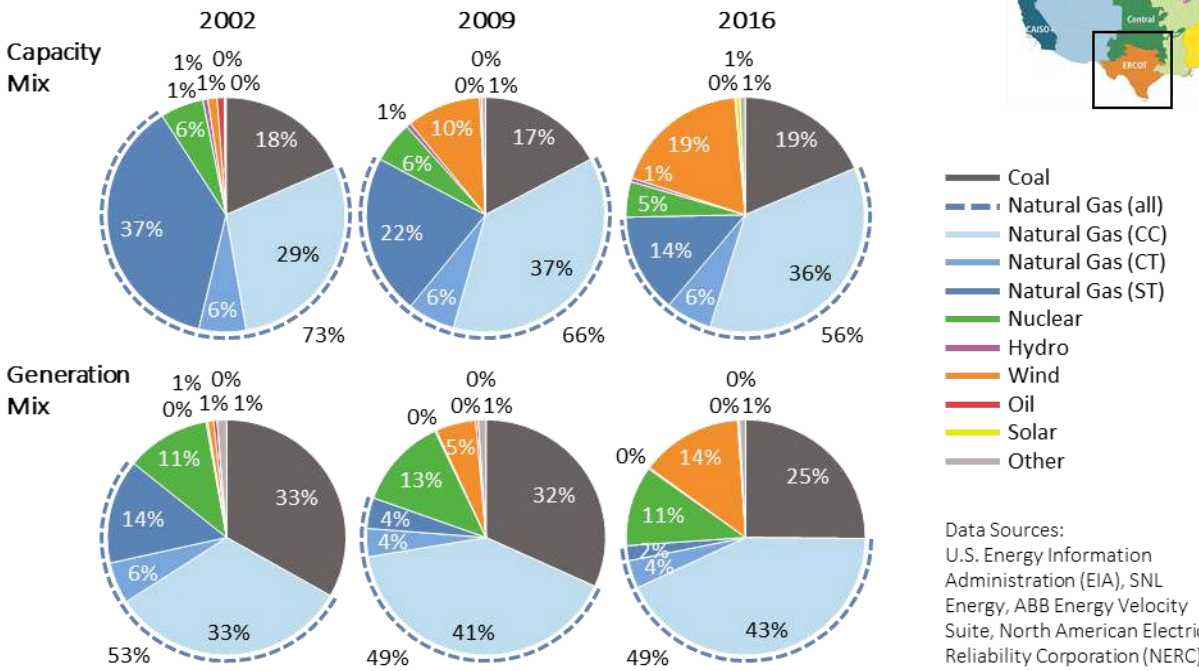
Retirements by Energy Source, 2002-2016

	# of Generators	MW
Coal	3	363
Natural Gas	155	14,894
Nuclear	0	0
Oil	10	17
Hydro	6	26
Other (all other sources)	23	234
*Total % Cap. Reduction**	*13.3%*	15,534

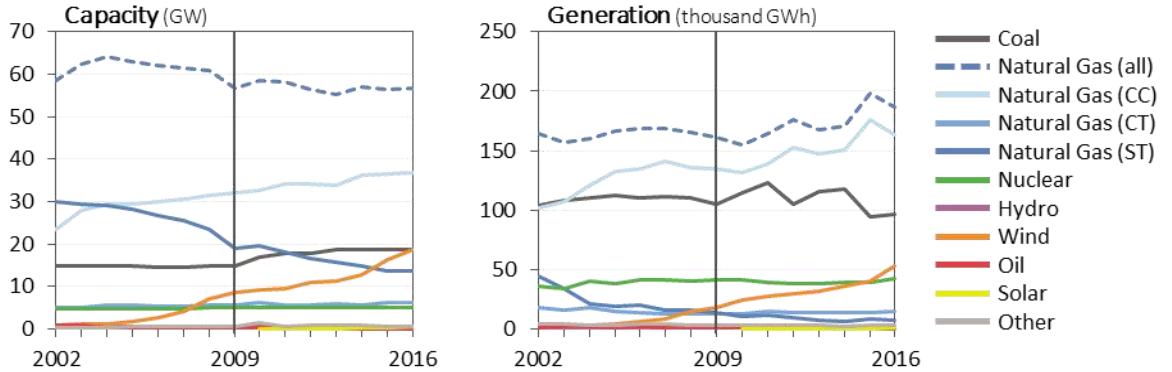
NERC Reserve Margin, 2017 (2016 LTRA)

	Target	Actual
ERCOT	13.75%	17.45%

ERCOT Regional Profile



Data Sources:
U.S. Energy Information Administration (EIA), SNL Energy, ABB Energy Velocity Suite, North American Electric Reliability Corporation (NERC)



Capacity & Generation by Energy Source, 2002 & 2016

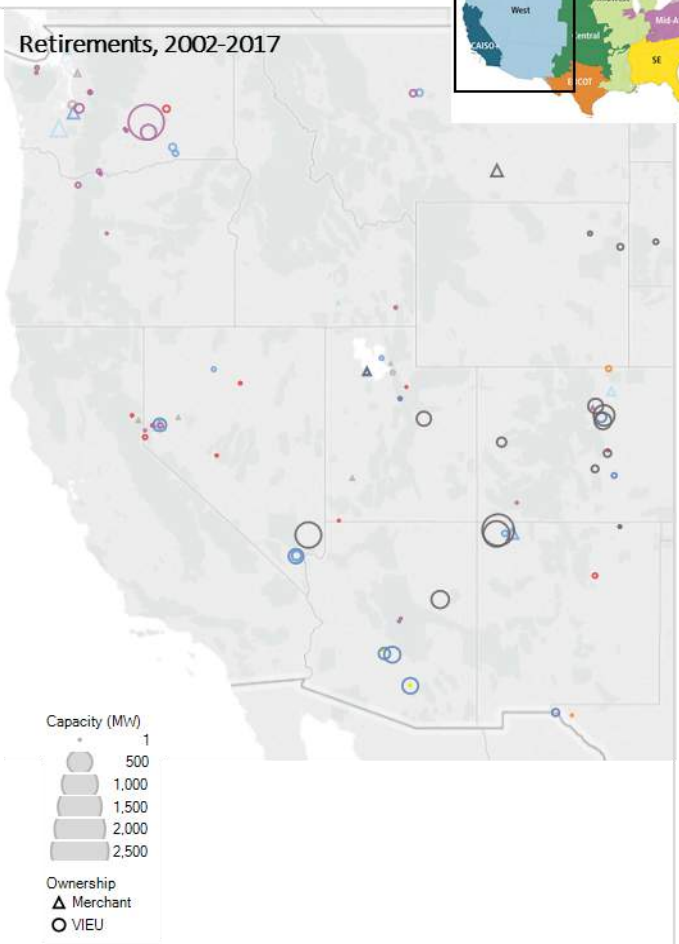
Energy Source	Capacity 2002 GW	Capacity 2002 %	Capacity 2016 GW	Capacity 2016 %	Generation 2002 thous. GWh	Generation 2002 %	Generation 2016 thous. GWh	Generation 2016 %
Coal	14.9	*18%*	18.8	*19%*	103.8	*33%*	96.1	*25%*
Natural Gas	58.6	*73%*	56.9	*56%*	164.1	*53%*	186.2	*49%*
Combined Cycle (CC)	23.3	*29%*	36.7	*36%*	101.6	*33%*	163.7	*43%*
Combustion Turbine (CT)	5.2	*6%*	6.4	*6%*	17.7	*6%*	14.6	*4%*
Steam Turbine (ST)	30.1	*37%*	13.8	*14%*	44.7	*14%*	7.9	*2%*
Nuclear	4.7	*6%*	5.0	*5%*	35.6	*11%*	42.1	*11%*
Hydro	0.6	*1%*	0.5	*1%*	0.7	*0%*	0.8	*0%*
Wind	1.0	*1%*	18.8	*19%*	2.4	*1%*	52.7	*14%*
Oil	0.8	*1%*	0.1	*0%*	1.6	*1%*	0.2	*0%*
Solar	0.0	*0%*	0.6	*1%*	0.0	*0%*	0.7	*0%*
Other	0.2	*0%*	0.7	*1%*	3.9	*1%*	3.2	*1%*
Total	**80.8**	*100%*	**101.3**	*100%*	**312.1**	*100%*	**382.0**	*100%*

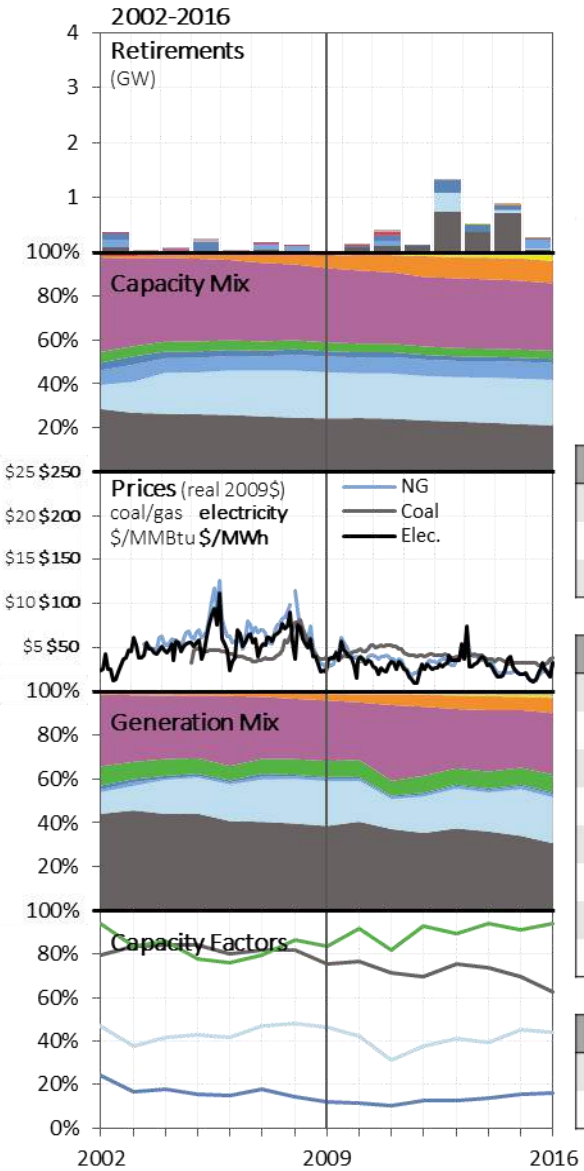
West Regional Profile

Energy Sources

- Coal
- Natural Gas (CC)
- Natural Gas (CT)
- Natural Gas (ST)
- Nuclear
- Hydro
- Wind
- Oil
- Solar
- Other

Notes:
Capacity values are summer capacity. Data for utility-scale resources only (1+ MW nameplate capacity). Natural gas technologies: CC = combined cycle, CT = combustion turbine, ST = steam turbine. Ownership type: VIEU = vertically integrated electric utility. Map includes 2017 Q1 actual and Q2-4 announced retirements. Prices: Natural gas = NW Sumas, Coal = Powder River Basin, Electricity = Mid-Columbia. *Total % Capacity Reduction calculation: retired capacity / (retired capacity + 2016 operational capacity)



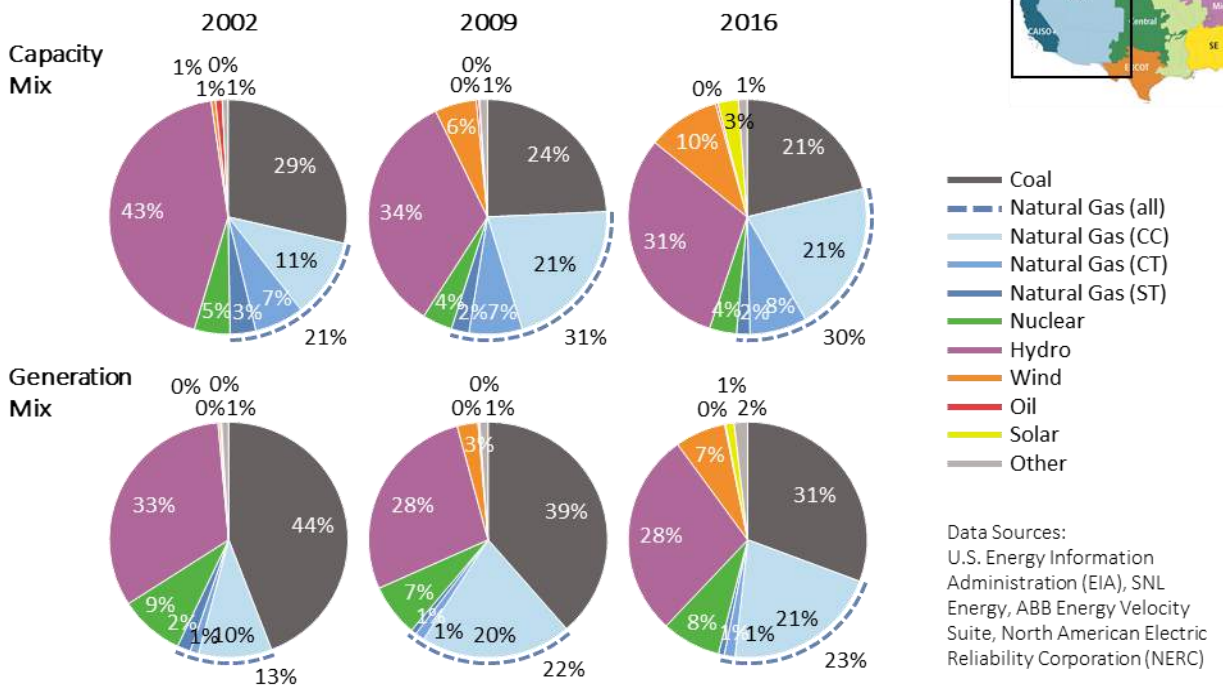


Total Capacity & Generation	2002	2016
Capacity (MW)	99,795	138,238
Generation (GWh)	452,765	524,861

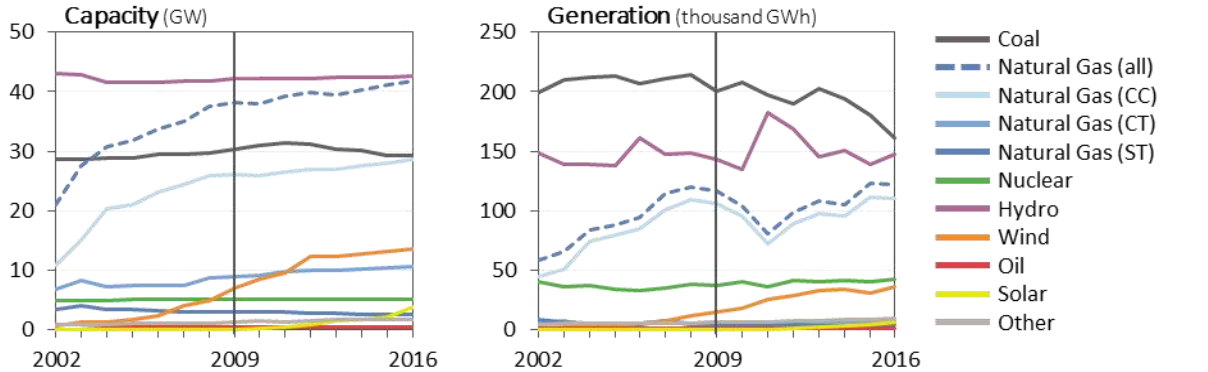
Retirements by Energy Source, 2002-2016	# of Generators	MW
Coal	29	2,292
Natural Gas	81	1,900
Nuclear	0	0
Oil	70	141
Hydro	38	171
Other (all other sources)	48	180
*Total % Cap. Reduction**	*3.3%*	4,683

NERC Reserve Margin, 2017 (2016 LTRA)	Target	Actual
WECC	15.90%	26.80%

West Regional Profile



Data Sources: U.S. Energy Information Administration (EIA), SNL Energy, ABB Energy Velocity Suite, North American Electric Reliability Corporation (NERC)



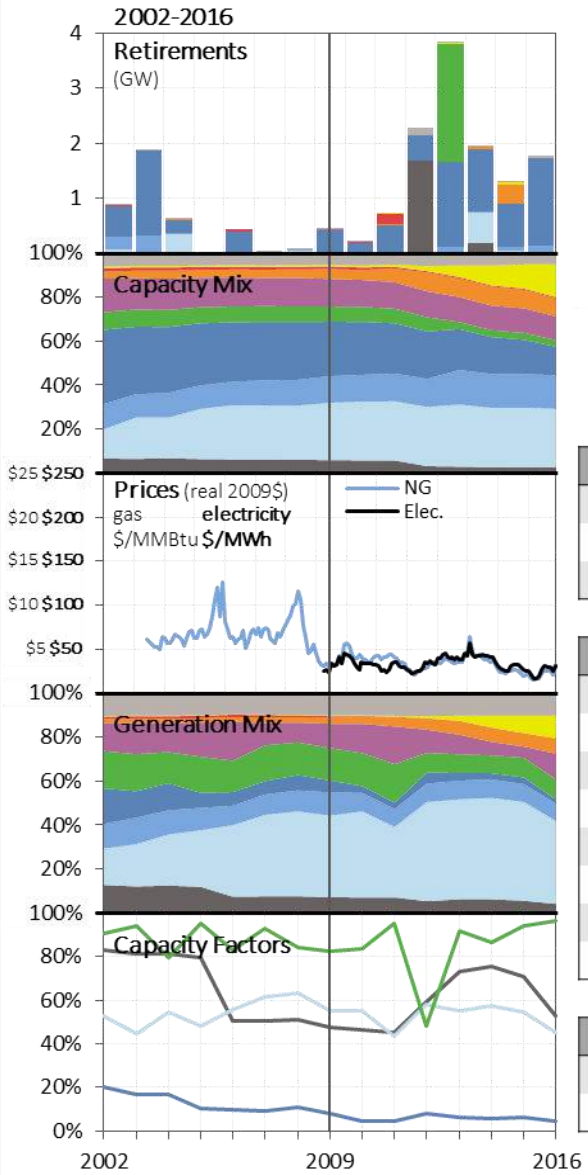
Capacity & Generation by Energy Source, 2002 & 2016

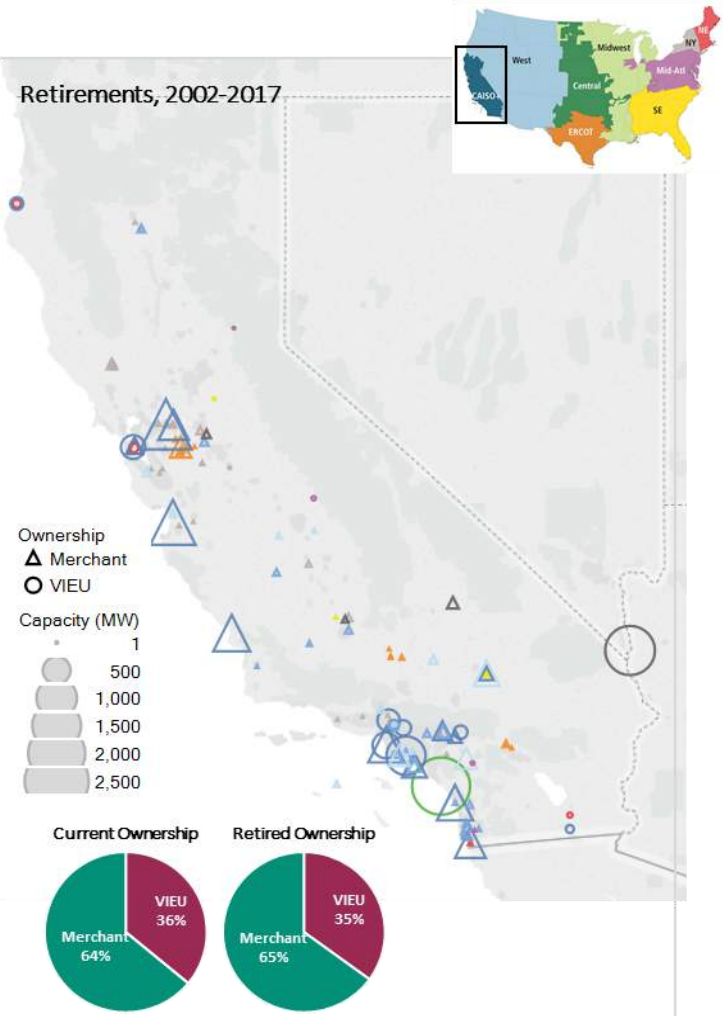
Energy Source	Capacity 2002 GW	%	Capacity 2016 GW	%	Generation 2002 thous. GWh	%	Generation 2016 thous. GWh	%
Coal	28.6	*29%*	29.3	*21%*	199.9	*44%*	161.3	*31%*
Natural Gas	21.1	*21%*	41.8	*30%*	58.4	*13%*	121.8	*23%*
Combined Cycle (CC)	10.9	*11%*	28.6	*21%*	44.9	*10%*	110.0	*21%*
Combustion Turbine (CT)	6.7	*7%*	10.7	*8%*	5.2	*1%*	7.7	*1%*
Steam Turbine (ST)	3.5	*3%*	2.5	*2%*	8.3	*2%*	4.1	*1%*
Nuclear	4.8	*5%*	5.1	*4%*	39.9	*9%*	42.0	*8%*
Hydro	43.0	*43%*	42.6	*31%*	148.1	*33%*	147.3	*28%*
Wind	0.6	*1%*	13.6	*10%*	1.4	*0%*	36.1	*7%*
Oil	0.9	*1%*	0.4	*0%*	0.8	*0%*	0.7	*0%*
Solar	0.0	*0%*	3.8	*3%*	0.0	*0%*	6.0	*1%*
Other	0.8	*1%*	1.6	*1%*	4.3	*1%*	9.6	*2%*
Total	**99.8**	*100%*	**138.2**	*100%*	**452.8**	*100%*	**524.9**	*100%*

CAISO+ Regional Profile

Energy Sources
- Coal
- Natural Gas (CC)
- Natural Gas (CT)
- Natural Gas (ST)
- Nuclear
- Hydro
- Wind
- Oil
- Solar
- Other

Notes:
Capacity values are summer capacity. Data for utility-scale resources only (1+ MW nameplate capacity). Natural gas technologies: CC = combined cycle, CT = combustion turbine, ST = steam turbine. Ownership type: VIEU = vertically integrated electric utility. Map includes 2017 Q1 actual and Q2-4 announced retirements. Prices: Natural gas = SoCal Border, Electricity = CAISO SP15. *Total % Capacity Reduction calculation: retired capacity / (retired capacity + 2016 operational capacity)



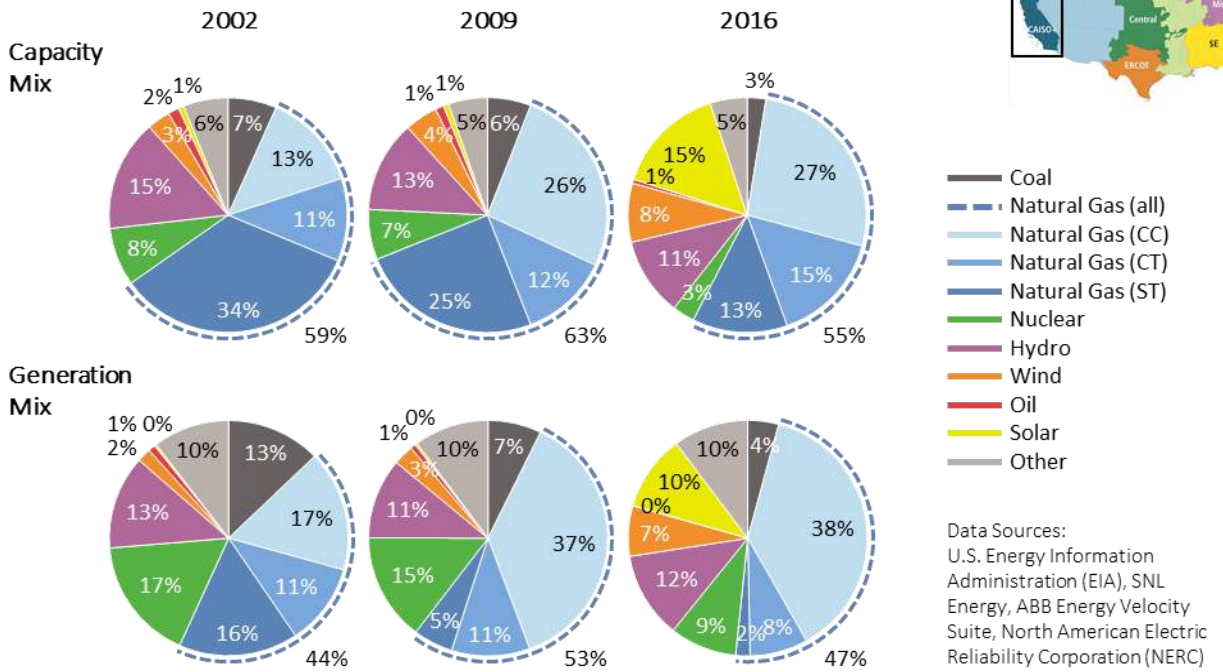


Total Capacity & Generation	2002	2016
Capacity (MW)	54,022	74,431
Generation (GWh)	203,028	208,137

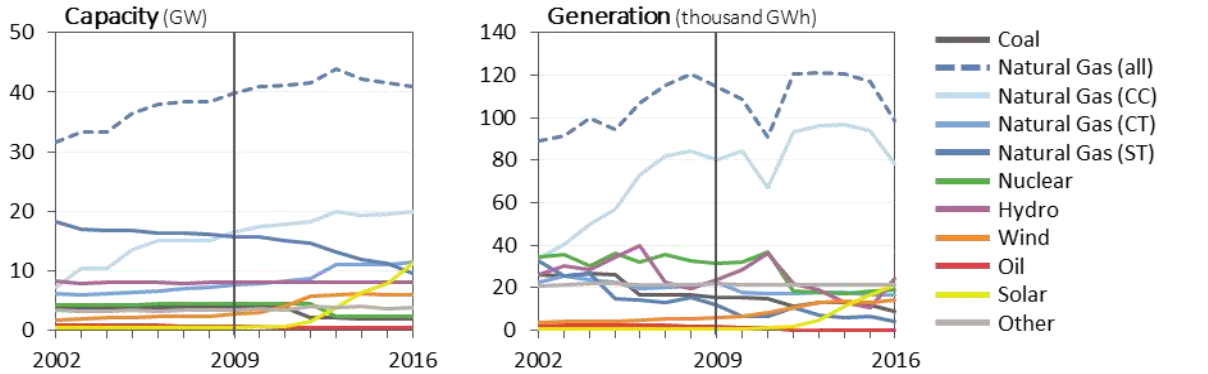
Retirements by Energy Source, 2002-2016	# of Generators	MW
Coal	7	1,855
Natural Gas	111	11,272
Nuclear	2	2,150
Oil	12	315
Hydro	7	26
Other (all other sources)	146	832
*Total % Cap. Reduction**	*18.1%*	16,450

NERC Reserve Margin, 2017 (2016 LTRA)	Target	Actual
CAISO	19.50%	24.40%

CAISO+ Regional Profile



Data Sources:
U.S. Energy Information Administration (EIA), SNL Energy, ABB Energy Velocity Suite, North American Electric Reliability Corporation (NERC)



Capacity & Generation by Energy Source, 2002 & 2016

Energy Source	Capacity 2002 GW	Capacity 2002 %	Capacity 2016 GW	Capacity 2016 %	Generation 2002 thous. GWh	Generation 2002 %	Generation 2016 thous. GWh	Generation 2016 %
Coal	3.6	*7%*	1.9	*3%*	26.0	*13%*	8.7	*4%*
Natural Gas	31.6	*59%*	40.9	*55%*	89.2	*44%*	98.8	*47%*
Combined Cycle (CC)	7.2	*13%*	19.9	*27%*	33.6	*17%*	78.3	*38%*
Combustion Turbine (CT)	6.2	*11%*	11.4	*15%*	22.7	*11%*	16.4	*8%*
Steam Turbine (ST)	18.3	*34%*	9.6	*13%*	32.9	*16%*	4.0	*2%*
Nuclear	4.3	*8%*	2.2	*3%*	34.4	*17%*	18.9	*9%*
Hydro	8.3	*15%*	8.0	*11%*	26.1	*13%*	24.6	*12%*
Wind	1.7	*3%*	6.0	*8%*	3.8	*2%*	14.4	*7%*
Oil	0.8	*2%*	0.4	*1%*	2.0	*1%*	0.1	*0%*
Solar	0.4	*1%*	11.2	*15%*	0.6	*0%*	21.5	*10%*
Other	3.3	*6%*	3.7	*5%*	21.0	*10%*	21.2	*10%*
Total	**54.0**	*100%*	**74.4**	*100%*	**203.0**	*100%*	**208.1**	*100%*

Appendix B: VRE Integration Studies

Numerous technical studies on electricity systems in most regions of the Nation have concluded that significantly higher levels of VRE can be successfully integrated without compromising resource adequacy.[hhhh] Demonstrating resource adequacy is essential, but achieving the modeled levels of VRE penetration requires a full consideration of "all-in" costs, land use, siting, and other environmental impacts; sustainable economics for non-wind and solar resources; for some studies, required changes at the distribution level; wholesale market design and organizational changes; spending on relevant transmission and distribution grid modernization activities; and ensuring all aspects of operational reliability.[iiii] These caveats are non-trivial, as they would be for any substantial major changes in the electric power system.

Table B-1. VRE Integration Studies [471]

Region	VRE Pen.	Author	Study Year	Study Title
United States	50%	NREL	2012	*Renewable Electricity Futures Study*
Western Interconnection	33%	NREL	2013	*Western Wind and Solar Integration Study: Phase 2*
	33%	GE Energy	2014	*Western Wind and Solar Integration Study Phase 3 – Frequency Response and Transient Stability*
	33%	GE Energy	2015	*Western Wind and Solar Integration Study Phase 3A: Low Levels of Synchronous Generation*
	35%	E3 and NREL	2015	*Western Interconnection Flexibility Assessment*
	52%	NREL	2015	*Renewable Electricity Futures: Operational Analysis of the Western Interconnection at Very High Renewable Penetrations*
CAISO	12%	CAISO	2010	*Integration of Renewable Resources at 20% RPS*
	50%[#]	GE Energy	2011	*California ISO Frequency Response Study*
	37%	E3	2014	*Investigating a Higher Renewables Portfolio Standard in California*

[hhhh] However, these studies (particularly those examining high VRE levels) may often assume (or ignore) modeled conditions that could be difficult and/or costly to achieve in practice, such as a large transmission buildout that may face siting or other obstacles, ability of non-wind and solar plants to remain financially viable and thus available, institutional changes, or, for one study, synchronization of all three interconnections.

[iiii] Operational reliability (which includes ensuring a set of ERS are maintained to help the electric system react to sudden stability disruptions or unanticipated losses of system components in real-time) is just as important as the resource adequacy aspect of BPS reliability. But modeling all needed aspects of operational reliability is very difficult computationally, and so not usually examined in its totality in these studies. For example, NREL in its Renewable Electricity Futures Study states, "The study did not conduct a full reliability analysis, which would include sub-hourly, stability, and AC power flow analysis." In fact, page xviii of that study qualitatively concludes "Additional challenges to power system planning and operation would arise in a high renewable electricity future, including management of low-demand periods." http://www.nrel.gov/docs/fy12osti/52409-1.pdf

	45%	NREL	2016	*Low-Carbon Grid Study*
West	35%	GE Energy	2010	*Western Wind and Solar Integration Study: Phase 1*
	17%	LBNL, ANL, NREL	2013	*Integrating Solar PV in Utility System Operations*
	30%	Xcel Energy	2011	*Wind Induced Coal Plant Cycling Costs and the Implications of Wind Curtailment for Public Service of Colorado*
	18%*	Navigant, Sandia, PNNL	2011	*Large-Scale Solar Integration Study*
	17%	Idaho Power	2014	*Solar Integration Study Report*
	9%	Portland General Electric	2014	*2013 Integrated Resource Plan: Appendix D PGE Wind Integration Study Phase 4*
	47%*	PacifiCorp	2017	*2017 Integrated Resource Plan*
ERCOT	17%	GE Energy	2008	*Analysis of Wind Generation Impact on ERCOT Ancillary Services Requirements*
	47%	Brattle	2013	*Exploring Natural Gas and Renewables in ERCOT Part II: Future Generation Scenarios for Texas*
Eastern Interconnection	30%	EnerNex	2011	*Eastern Wind Integration and Transmission Study*
	25%#	GE Energy	2013	*Eastern Frequency Response Study*
	30%	NREL	2016	*Eastern Renewable Generation Integration Study*
Central	40%	EnerNex et al.	2010	*Nebraska Statewide Wind Integration Study*
	40%	Charles River Associates	2010	*SPP WITF Wind Integration Study*
	60%#	SPP	2016	*2016 Wind Integration Study*
Central and Southeast	20%	EPRI and LCG	2011	*DOE: Integrating Midwest Wind Energy into Southeast Electricity Markets*
Southeast	7%	PNNL	2014	*Duke Energy Photovoltaic Integration Study: Carolinas Service Areas*
Mid-Atlantic	30%	GE Energy	2014	*PJM Renewable Integration Study*
	21%	Navigant	2016	*Virginia Solar Pathways Project: Study 2 - Solar PV Generation System Integration Impacts*
Midwest	50%	GE Energy	2014	*Minnesota Renewable Energy Integration and Transmission Study*
	37%*	Northern States Power	2015	*2015 Resource Plan: Appendix E – Renewable Energy*
New York	12%	NYISO	2010	*Growing Wind: Final Report of the NYISO 2010 Wind Generation Study*
	15%	NYISO	2016	*Solar Impact on Grid Operations-An Initial Assessment*
New England	24%	GE Energy	2010	*New England Wind Integration Study*

Hawaii	20%	NREL and GE Energy	2013	*Hawaii Solar Integration Study*

Notes: VRE penetration listed as percentage of annual energy (i.e. MWH, not MW), except where marked (# indicates instantaneous penetration, * indicates VRE nameplate as percentage of peak load); VRE includes only wind and solar.

Appendix C: Power Plant Cycling

Traditional baseload power plants were designed to operate primarily at constant output levels with limited cycling.[472] As the electricity system continues to evolve and market conditions change, these plants are increasingly following load or being required to more frequently adjust the load and the on/off dispatch of their units. The extra costs incurred to do so can affect a plant's retirement decision.

Every time a power plant is turned off and on, the boiler, steam lines, turbine, and auxiliary components go through unavoidably large thermal and pressure stresses, which cause damage.[473] This damage is made worse for high-temperature components by the phenomenon called creep-fatigue interaction. While cycling-related increases in failure rates may not be noted immediately, critical components will eventually start to fail. Shorter component life expectancies will result in higher plant equivalent forced outage rates[jjj] and/or higher capital and maintenance costs to replace components at or near the end of their service lives.[474] In addition, it may result in shortened overall plant life. How soon these detrimental effects will occur depends on the amount of creep damage present and the specific types and frequency of the cycling.

Several VRE integration studies, including those performed by NREL and the Western Electricity Coordinating Council, have recognized that high penetration of VRE into the wholesale electricity markets could increase cycling of conventional power plants.[475] Today, coal unit cycling does occur with current levels of wind and solar.[kkk] [476] [477] [478] The retirement of many of the older, smaller coal-fired units that have provided cycling operation in the past will require more flexibility in the remaining coal fleet through improved technologies.[479]

General Electric has also studied the effects of cycling on power plant maintenance and operations and observes the following:

- Wear-and-tear cycling costs can increase with the changing power portfolio or fuel prices.
- These costs are generator-specific. They can impact financial viability of generators.
- Incorporating cycling costs into commitment and dispatch decisions can change these decisions.
- Solar and wind generation resources have different impacts on cycling.
- Operational and/or physical changes to coal/gas plants can increase flexibility. Retrofits have the potential to increase overall profitability. [480]

The cycling issues described above have similar impacts on gas-fired steam and older, combined-cycle generators. Some coal and NGCC units can (and have) made capital investments to improve their cycling performance to remain competitive.[481]

[jjj] NERC defines equivalent forced outage rates as "the probability that a unit will not meet its demand periods for generating requirements because of forced outages or deratings." http://www.nerc.com/pa/RAPA/Pages/SummerVsWinterEFORdRates.aspx

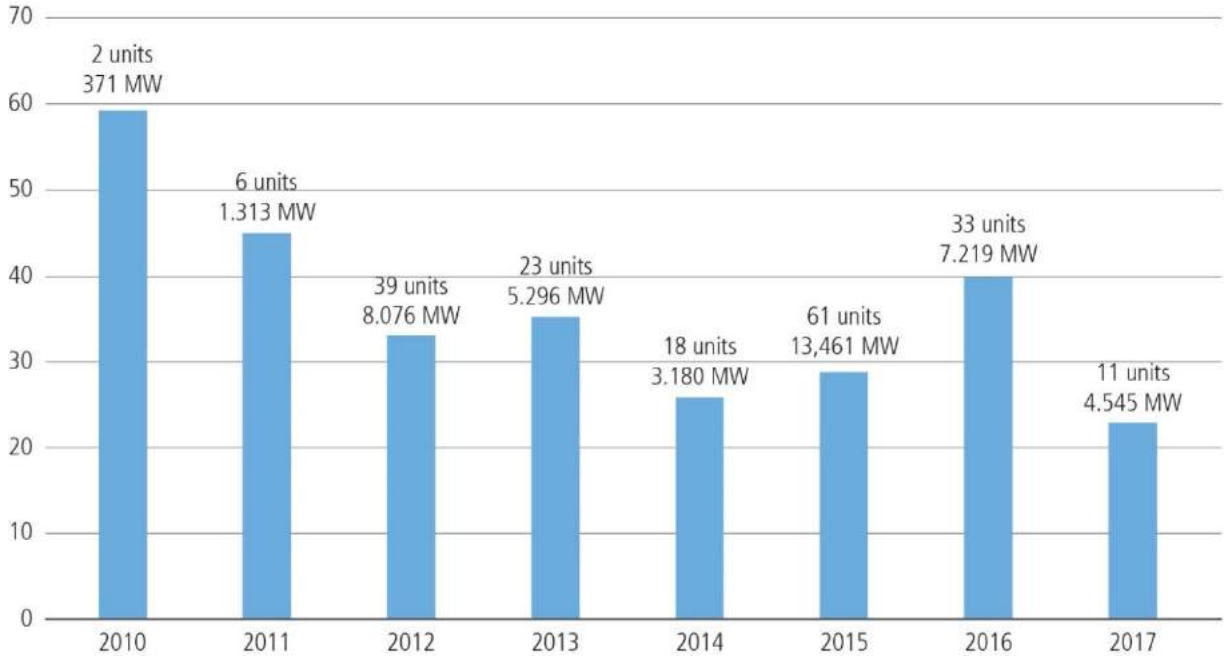
[kkk] "Existing thermal generation plants are being forced to cycle more with the addition of intermittent wind generation and low variable cost base-load generation." http://www.energy-tech.com/ram/article_65131bb2-42d0-11e6-8c80-e729cc172758.html

Existing U.S. nuclear power plants were designed with a similar goal of operations at a set generation output, and—with few exceptions—they were not designed with flexible operation modes. Fuel is loaded in 18-month or 24-month cycles, thus keeping the marginal cost of operation low. The U.S. Nuclear Regulatory Commission prohibits nuclear power plant control systems from interfacing or being automatically controlled from grid network control systems,[482] so what limited load following is allowed must be scheduled from one to three days in advance and is in small increments of power output.[483]

Nuclear units receive no benefit to load following or ramping, as they do not save on fuel costs. Like fossil plants, ramping a nuclear plant will also result in more wear and tear due to thermal gradients and mechanical stresses and will likely increase capital expenditures. Less restrictive, but still carefully controlled, nuclear load following is permitted and utilized in other countries, such as France, for which nuclear has a higher percentage of electricity output on the system.

A review of the literature about coal plant cycling by Argonne National Laboratory[484] reports that coal plant heat rates increase with plant age, while plant availability decreases. Cycling and load following exacerbate the effects of plant aging and reduce component life.[485] These operational patterns impose higher costs (including maintenance and fuel costs), as well as lower capacity factors (Figure 8.1).[IIII]

Figure 8.1. Average Three-Year Capacity Factors for Retired U.S. Coal Plants[486]



Plants that have retired since 2010 tended to have lower average capacity factors.

[IIII] A lower capacity factor means fixed costs are spread over fewer operating hours (i.e. megawatt-hours), which in turn means higher unit costs ($/megawatt-hour).

Endnotes

[1] "Frequently Asked Questions: How Many Power Plants Are There in the United States?," Energy Information Administration, accessed October 19, 2016, http://www.eia.gov/tools/faqs/faq.cfm?id=65&t=2, quoted in Department of Energy (DOE), Transforming the Nation's Electricity System: The Second Installment of The Quadrennial Energy Review (Washington, DC: DOE, January 2017), https://www.energy.gov/sites/prod/files/2017/02/f34/Quadrennial%20Energy%20Review--Second%20Installment%20%28Full%20Report%29.pdf.

[2] Ellen Flynn Giles and Kathy L. Brown, eds., *2015 UDI Directory of Electric Power Producers and Distributors: 123rd Edition of the Electrical World Directory* (New York, NY: Platts, 2014), vi–vii, https://www.platts.com/im.platts.content/downloads/udi/eppd/eppddir.pdf, quoted in Department of Energy (DOE), *Transforming the Nation's Electricity System: The Second Installment of The Quadrennial Energy Review* (Washington, DC: DOE, January 2017), https://www.energy.gov/sites/prod/files/2017/02/f34/Quadrennial%20Energy%20Review--Second%20Installment%20%28Full%20Report%29.pdf.

[3] Julia Pyper, "The US Solar Market Is Now 1 Million Installations Strong," *Greentech Media*, April 21, 2016, https://www.greentechmedia.com/articles/read/The-U.S.-Solar-Market-Now-One-Million-Installations-Strong, quoted in Department of Energy (DOE), *Transforming the Nation's Electricity System: The Second Installment of The Quadrennial Energy Review* (Washington, DC: DOE, January 2017), https://www.energy.gov/sites/prod/files/2017/02/f34/Quadrennial%20Energy%20Review--Second%20Installment%20%28Full%20Report%29.pdf.

[4] "Electric Substations," Platts, generated March 6, 2009, http://www.platts.com/IM.Platts.Content/ProductsServices/Products/gismetadata/substatn.pdf quoted Department of Energy (DOE), *Transforming the Nation's Electricity System: The Second Installment of The Quadrennial Energy Review* (Washington, DC: DOE, January 2017), https://www.energy.gov/sites/prod/files/2017/02/f34/Quadrennial%20Energy%20Review--Second%20Installment%20%28Full%20Report%29.pdf.

[5] Ellen Flynn Giles and Kathy L. Brown, eds., *2015 UDI Directory of Electric Power Producers and Distributors: 123rd Edition of the Electrical World Directory* (New York, NY: Platts, 2014), vi–vii, https://www.platts.com/im.platts.content/downloads/udi/eppd/eppddir.pdf, quoted in Department of Energy (DOE), *Transforming the Nation's Electricity System: The Second Installment of The Quadrennial Energy Review* (Washington, DC: DOE, January 2017), https://www.energy.gov/sites/prod/files/2017/02/f34/Quadrennial%20Energy%20Review--Second%20Installment%20%28Full%20Report%29.pdf.

[6] Ellen Flynn Giles and Kathy L. Brown, eds., *2015 UDI Directory of Electric Power Producers and Distributors: 123rd Edition of the Electrical World Directory* (New York, NY: Platts, 2014), vi, https://www.platts.com/im.platts.content/downloads/udi/eppd/eppddir.pdf, quoted in Department of Energy (DOE), *Transforming the Nation's Electricity System: The Second Installment of The Quadrennial Energy Review* (Washington, DC: DOE, January 2017), https://www.energy.gov/sites/prod/files/2017/02/f34/Quadrennial%20Energy%20Review--Second%20Installment%20%28Full%20Report%29.pdf.

[7] "Electric Power Sales, Revenue, and Energy Efficiency Form EIA-861 Detailed Data Files," Energy Information Administration, last modified October 6, 2016, https://www.eia.gov/electricity/data/eia861/, as quoted in Department of Energy (DOE), *Transforming the Nation's Electricity System: The Second Installment of The Quadrennial Energy Review* (Washington, DC: DOE, January 2017), https://www.energy.gov/sites/prod/files/2017/02/f34/Quadrennial%20Energy%20Review--Second%20Installment%20%28Full%20Report%29.pdf.

[8] International Monetary Fund, *World Economic Outlook Database, Entire Dataset, by Country Groups, GDP, Current Prices* (International Monetary Fund, April 2016), https://www.imf.org/external/pubs/ft/weo/2016/01/weodata/download.aspx, quoted in Department of Energy (DOE), *Transforming the Nation's Electricity System: The Second Installment of The Quadrennial Energy Review* (Washington, DC: DOE, January 2017), https://www.energy.gov/sites/prod/files/2017/02/f34/Quadrennial%20Energy%20Review--Second%20Installment%20%28Full%20Report%29.pdf.

[9] Sara Hoff, "U.S. Electric System Is Made Up of Interconnections and Balancing Authorities," *Today In Energy*, Energy Information Administration, July 20, 2017, https://www.eia.gov/todayinenergy/detail.php?id=27152.

[10] EIA, Internal Analysis, June 2017.

[11] PJM Interconnection, "PJM Provides the Following Documents and Information for the Department's Consideration as It Prepares Its Report in Response to the Secretary's Memorandum of April 14, 2017," sent by PJM Interconnection to the Department of Energy, May 3, 2017.

[12] North American Electric Reliability Corporation (NERC), "Synopsis of NERC Reliability Assessments, the Changing Resource Mix, and the Impacts of Conventional Generation Retirements," unpublished materials submitted to the Department of Energy, May 9, 2017.

[13] Adapted from Federal Energy Regulatory Commission (FERC), *Reliability Primer* (Washington, DC: FERC, December 2016), 15, https://www.ferc.gov/legal/staff-reports/2016/reliability-primer.pdf.

[14] *Merriam-Webster*, s.v. "premature," https://www.merriam-webster.com/dictionary/premature.

[15] North American Electric Reliability Corporation (NERC), "Synopsis of NERC Reliability Assessments, the Changing Resource Mix, and the Impacts of Conventional Generation Retirements," unpublished materials submitted to the Department of Energy, May 9, 2017.

[16] SANS Industrial Control Systems and Electricity Information Sharing and Analysis Center (E-ISAC), *Analysis of the Cyber Attack on the Ukrainian Power Grid: Defense Use Case* (Washington, DC: E-ISAC, March 2016), https://ics.sans.org/media/E-ISAC_SANS_Ukraine_DUC_5.pdf.

[17] "Form EIA-860m: Preliminary Monthly Electric Generator Inventory," Energy Information Administration, March 2017, https://www.eia.gov/electricity/data/eia860m/.

[18] Energy Information Administration, "Alaska State Profile and Energy Estimates," October 2016, https://www.eia.gov/state/analysis.php?sid=AK.

[19] Gerry Cauley (President and CEO, North American Electric Reliability Corporation), letter to Energy Secretary Rick Perry, May 9, 2017.

[20] Energy Information Administration (EIA), *Monthly Energy Review* (Washington, DC: EIA, June 2017), DOE/EIA-0035(2017/6), Table 7.2a, https://www.eia.gov/totalenergy/data/monthly/#electricity.

[21] Energy Information Administration (EIA), *Monthly Energy Review* (Washington, DC: EIA, June 2017), DOE/EIA-0035(2017/6), Table 7.6, https://www.eia.gov/totalenergy/data/monthly/#electricity.

[22] "Form EIA-860m: Preliminary Monthly Electric Generator Inventory," Energy Information Administration, March 2017, https://www.eia.gov/electricity/data/eia860m/, and internal analysis, June 2017.

[23] Energy Information Administration (EIA), *Electric Power Monthly* (Washington, DC: EIA, June 2017). https://www.eia.gov/electricity/monthly/.

[24] N. Kumar, P. Besuner, S. Lefton, D. Agan, and D. Hilleman, *Power Plant Cycling Costs* (Golden, CO: National Renewable Energy Laboratory, April 2012), iv, http://www.nrel.gov/docs/fy12osti/55433.pdf.

[25] Department of Energy (DOE), *Transforming the Nation's Electricity System: The Second Installment of the Quadrennial Energy Review* (Washington, DC: DOE, January 2017), 3-73, https://www.energy.gov/sites/prod/files/2017/02/f34/Quadrennial%20Energy%20Review--Second%20Installment%20%28Full%20Report%29.pdf.

[26] "Form EIA-860m: Preliminary Monthly Electric Generator Inventory," Energy Information Administration, March 2017, https://www.eia.gov/electricity/data/eia860m/.

[27] "Form EIA-860m: Preliminary Monthly Electric Generator Inventory," Energy Information Administration, March 2017, https://www.eia.gov/electricity/data/eia860m/.

[28] Massachusetts et al. v. Environmental Protection Agency et al., 549 U.S. 497 (2007), https://www.law.cornell.edu/supct/html/05-1120.ZS.html.

[29] "Form EIA-860m: Preliminary Monthly Electric Generator Inventory," Energy Information Administration, March 2017, https://www.eia.gov/electricity/data/eia860m/.

[30] U.S. Energy Information Administration, "EIA-860 Electric Power Annual: Existing Capacity by Energy Source, by Producer, by State Back to 2000," November 2016, https://www.eia.gov/electricity/data.php#gencapacity.

[31] Energy Information Administration (EIA), "Monthly Update to Annual Electric Generator Report," March 2017, https://www.eia.gov/electricity/data/eia860m/.

[32] Scott Jell, "Most coal plants in the United States were built before 1990," Today in Energy, Energy Information Administration, April 17, 2017, https://www.eia.gov/todayinenergy/detail.php?id=30812.

[33] Energy Information Administration (EIA), *Monthly Energy Review* (Washington, DC: EIA, July 2017), Table 6.2, https://www.eia.gov/totalenergy/data/monthly/pdf/sec6_4.pdf.

[34] "Form EIA-860m: Preliminary Monthly Electric Generator Inventory" Energy Information Administration, March 2017, https://www.eia.gov/electricity/data/eia860m/.

[35] U.S. Energy Information Administration, "Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2017," April 2017, https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf.

[36] "Form EIA-860m: Preliminary Monthly Electric Generator Inventory," Energy Information Administration, March 2017, https://www. eia.gov/electricity/data/eia860m/.

[37] Scott Jell, "Most Coal Plants in the United States Were Built before 1990," *Today in Energy*, Energy Information Administration, April 17, 2017, https://www.eia.gov/todayinenergy/detail.php?id=30812.

[38] Richard J. Campbell, *Increasing the Efficiency of Existing Coal-Fired Power Plants* (Washington, DC: Congressional Research Service, December 20, 2013), R43343, https://fas.org/sgp/crs/misc/R43343.pdf.

[39] Energy Information Administration, "Today in Energy: Most coal plants in the United States were built before 1990," Accessed July 2017, https://www.eia.gov/todayinenergy/detail.php?id=30812.

[40] Energy Information Administration (EIA), "Monthly Update to Annual Electric Generator Report," March 2017, https://www.eia.gov/electricity/data/eia860m/.

[41] Energy Information Administration (EIA), "Monthly Update to Annual Electric Generator Report," March 2017, https://www.eia.gov/electricity/data/eia860m/.

[42] Owen Comstock, "Coal Made Up More Than 80% of Retired Electricity Generating Capacity in 2015," *Today in Energy,* Energy Information Administration, March 8, 2016, https://www.eia.gov/todayinenergy/detail.php?id=25272.

[43] Energy Information Administration, "Update on Retirements of Coal-Fired Power Plants" (presented to Secretary Ernest Moniz, November 8, 2016).

[44] Energy Information Administration (EIA), "Monthly Update to Annual Electric Generator Report," March 2017, https://www.eia.gov/electricity/data/eia860m/.

[45] Owen Comstock, "Coal Made Up More Than 80% of Retired Electricity Generating Capacity in 2015," *Today in Energy,* Energy Information Administration, March 8, 2016, https://www.eia.gov/todayinenergy/detail.php?id=25272.

[46] "Table B-1. Employees on Nonfarm Payrolls by Industry Sector and Selected Industry Detail," Department of Labor, Bureau of Labor Statistics, accessed November 4, 2016, http://www.bls.gov/news.release/empsit.t17.htm.

[47] Energy Information Administration, "U.S. Coal Flow, 2016," accessed August 7, 2017, https://www.eia.gov/totalenergy/data/monthly/pdf/flow/coal.pdf

[48] Energy Information Administration (EIA), *Monthly Energy Review* (Washington, DC: EIA, December 2016), Tables 3.7, 4.3, and 6.7, http://www.eia.gov/totalenergy/data/monthly/.

[49] "Quarterly Census of Employment and Wages," Department of Labor, Bureau of Labor Statistics, accessed August 4, 2017, http://www.bls.gov/cew/.

[50] Ed Malley, "Coal Power Plant Post-Retirement Options," POWER, September 1, 2016, http://www.powermag.com/coal-power-plant-post-retirement-options/.

[51] Augustine Kwon, "Natural Gas Generators Make Up the Largest Share of Overall U.S. Generation Capacity," *Today in Energy*, Energy Information Administration, April 20, 2017, https://www.eia.gov/todayinenergy/detail.php?id=30872.

[52] "Form EIA-860m: Preliminary Monthly Electric Generator Inventory," Energy Information Administration, March 2017, https://www. eia.gov/electricity/data/eia860m/.

[53] Augustine Kwon, "Natural Gas Generators Make Up the Largest Share of Overall U.S. Generation Capacity," *Today in Energy*, Energy Information Administration, April 20, 2017, https://www.eia.gov/todayinenergy/detail.php?id=30872.

[54] Energy Information Administration (EIA) analysis of data from "Form EIA-860," EIA, https://www.eia.gov/electricity/data/eia860/, and "Form EIA-923," EIA, https://www.eia.gov/electricity/data/eia923/.

[55] David Hurlbut, Scott Haase, Clayton Barrows, Lori Bird, Greg Brinkman, Jeff Cook, Megan Day, Victor Diakov, Elaine Hale, et al., *Navajo Generating Station & Federal Resource Planning: Volume 1: Sectoral, Technical, and Economic Trends* (Golden, CO: National Renewable Energy Laboratory, November 2016), NREL/TP-6A20-66506, http://www.nrel.gov/docs/fy17osti/66506.pdf.

[56] Energy Information Administration (EIA), *Electric Power Monthly* (Washington, DC: EIA, May 2017), Table 6.7.A, https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_6_07_a.

[57] Energy Information Administration (EIA), "Monthly Update to Annual Electric Generator Report," March 2017, https://www.eia.gov/electricity/data/eia860m/

[58] "Most Generator Retirements over the Past Decade Were Older Natural Gas-Fired Units," *Today in Energy*, Energy Information Administration, December 13, 2011, https://www.eia.gov/todayinenergy/detail.php?id=4290.

[59] Department of Energy (DOE), *Transforming the Nation's Electricity System: The Second Installment of The Quadrennial Energy Review* (Washington, DC: DOE, January 2017), 3-20, https://www.energy.gov/sites/prod/files/2017/02/f34/Quadrennial%20Energy%20Review--Second%20Installment%20%28Full%20Report%29.pdf.

[60] Michael Mobilia, "Most U.S. Nuclear Power Plants Were Built between 1970 and 1990," *Today in Energy*, Energy Information Administration, April 27, 2017, https://www.eia.gov/todayinenergy/detail.php?id=30972.

[61] "Form EIA-860m: Preliminary Monthly Electric Generator Inventory," Energy Information Administration, March 2017, https://www. eia.gov/electricity/data/eia860m/.

[62] Energy Information Administration (EIA), "Monthly Update to Annual Electric Generator Report," March 2017, https://www.eia.gov/electricity/data/eia860m/.

[63] U.S. Nuclear Regulatory Commission, "Backgrounder on Power Uprates for Nuclear Plants," April 2016, https://www.nrc.gov/reading-rm/doc-collections/fact-sheets/power-uprates.html.

[64] Nuclear Energy Institute (NEI), "Environment Emissions Prevented," August 2017, https://www.nei.org/Knowledge-Center/Nuclear-Statistics/Environment-Emissions-Prevented.

[65] Nuclear Energy Institute, *Nuclear Energy's Economic Benefits—Current and Future* (Washington, DC: Nuclear Energy Institute, April 2014), https://www.nei.org/corporatesite/media/filefolder/policy/papers/jobs.pdf.

[66] Department of Energy (DOE), *Transforming the Nation's Electricity System: The Second Installment of The Quadrennial Energy Review* (Washington, DC: DOE, January 2017), https://www.energy.gov/sites/prod/files/2017/02/f34/Quadrennial%20Energy%20Review--Second%20Installment%20%28Full%20Report%29.pdf.

[67] Webber, Michael W. University of Texas. "Why the withering nuclear power industry threatens US national security", The Conversation, August 10, 2017, https://theconversation.com/why-the-withering-nuclear-power-industry-threatens-us-national-security-82351

[68] Robert Walton, "Exelon, New York Regulators Defend Nuclear Credits under Clean Energy Standard," *Utility Dive*, February 1, 2017, http://www.utilitydive.com/news/exelon-new-york-regulators-defend-nuclear-credits-under-clean-energy-stand/435232/.

[69] Robert Walton, "Exelon, New York Regulators Defend Nuclear Credits under Clean Energy Standard," *Utility Dive*, February 1, 2017, http://www.utilitydive.com/news/exelon-new-york-regulators-defend-nuclear-credits-under-clean-energy-stand/435232/.

[70] Ronaldo Szilard, Phil Sharpe, Edward Kee, Edward Davis, and Eugene Grencheck, *Economic and Market Challenges Facing the U.S. Nuclear Commercial Fleet Energy* (Idaho National Laboratory and Center for Advanced Energy Studies, September 2016), https://gain.inl.gov/Shared%20Documents/Economics-Nuclear-Fleet.pdf.

[71] Ronaldo Szilard, Phil Sharpe, Edward Kee, Edward Davis, and Eugene Grencheck, Economic and Market Challenges Facing the U.S. Nuclear Commercial Fleet Energy (Idaho National Laboratory and Center for Advanced Energy Studies, September 2016), https://gain.inl.gov/Shared%20Documents/Economics-Nuclear-Fleet.pdf.

[72] Nuclear Energy Institute, "Nuclear by the Numbers," February 2017, https://www.nei.org/CorporateSite/media/filefolder/Policy/Wall%20Street/Nuclear_by_the_Numbers.pdf?ext=.pdf.

[73] Energy Information Agency, Today in Energy "Three Mile Island is the latest nuclear power plant to announce retirement plans," June 13, 2017, https://www.eia.gov/todayinenergy/detail.php?id=31612.

[74] : Energy Information Agency, Today in Energy "Three Mile Island is the latest nuclear power plant to announce retirement plans," June 13, 2017, https://www.eia.gov/todayinenergy/detail.php?id=31612.

[75] "Status of License Renewal Applications and Industry Activities," Nuclear Regulatory Commission, last modified June 27, 2017, https://www.nrc.gov/reactors/operating/licensing/renewal/applications.html.

[76] "Status of License Renewal Applications and Industry Activities," Nuclear Regulatory Commission, last modified June 27, 2017, https://www.nrc.gov/reactors/operating/licensing/renewal/applications.html.

[77] "U.S. Nuclear Operating Plant Basic Information," Nuclear Energy Institute, last modified April 2017, https://www.nei.org/Knowledge-Center/Nuclear-Statistics/US-Nuclear-Power-Plants/US-Nuclear-Operating-Plant-Basic-Information.

[78] Nuclear Energy Institute "Nuclear Costs in Context" April 2017. www.nei.org/Master-Document-Folder/Backgrounders/White-Papers/Nuclear-Costs-in-Context.

[79] Nicholas Steckler, "Half of U.S. Nuclear Power Plants are Underwater," Bloomberg New Energy Finance, June 13, 2017

[80] Nuclear Regulatory Commission, "Status of License Renewal Applications and Industry Activities," June 27, 2017, https://www.nrc.gov/reactors/operating/licensing/renewal/applications.html.

[81] Nuclear Energy Institute, "License Renewal of Nuclear Power Plants," November 2016, https://www.nei.org/Master-Document-Folder/Backgrounders/Fact-Sheets/License-Renewal-of-Nuclear-Power-Plants.

[82] Light Water Reactor Sustainability Program, U.S. Department of Energy Office of Nuclear Energy (Estimate provided by senior program staff).

[83] Chris Mudrick, "Industry Perspective: Overcoming Revenue Challenges" (presented at the Energy Information Administration's 2017 Energy Conference, Washington, DC, June 26, 2017), https://www.eia.gov/conference/2017/pdf/presentations/chris_mudrick.pdf.

[84] S. Nuclear Regulatory Commission, "Status of License Renewal Applications and Industry Activities," June 27, 2017, https://www.nrc.gov/reactors/operating/licensing/renewal/applications.html.

[85] Energy Information Agency, Today in Energy "Three Mile Island is the latest nuclear power plant to announce retirement plans," June 13, 2017, https://www.eia.gov/todayinenergy/detail.php?id=31612.

[86] Nuclear Energy Institute, "Nuclear by the Numbers," February 2017, https://www.nei.org/CorporateSite/media/filefolder/Policy/Wall%20Street/Nuclear_by_the_Numbers.pdf?ext=.pdf.

[87] Department of Energy (DOE), *Transforming the Nation's Electricity System: The Second Installment of The Quadrennial Energy Review* (Washington, DC: DOE, January 2017), 3-16, https://www.energy.gov/sites/prod/files/2017/02/f34/Quadrennial%20Energy%20Review--Second%20Installment%20%28Full%20Report%29.pdf.

[88] Office of Energy Efficiency & Renewable Energy, "2014 Hydropower Market Report," April 2015, https://energy.gov/sites/prod/files/2015/05/f22/2014%20Hydropower%20Market%20Report_20150512_rev6.pdf

[89] R. Uria-Martinez, P. O'Connor, and M. Johnson, "Hydropower Market Report: 2017 Update (April)," Oak Ridge National Laboratory, April 2017, https://energy.gov/eere/water/downloads/2014-hydropower-market-report.

[90] Energy Information Administration (EIA), *Monthly Energy Review* (Washington, DC: EIA, June 2016), http://www.eia.gov/totalenergy/data/monthly.

[91] Department of Energy (DOE), *Transforming the Nation's Electricity System: The Second Installment of The Quadrennial Energy Review* (Washington, DC: DOE, January 2017), 3-16, https://www.energy.gov/sites/prod/files/2017/02/f34/Quadrennial%20Energy%20Review--Second%20Installment%20%28Full%20Report%29.pdf.

[92] Allen McFarland, "Hydroelectric Generators Are among the United States' Oldest Power Plants," *Today in Energy*, Energy Information Administration, March 13, 2017, https://www.eia.gov/todayinenergy/detail.php?id=30312.

[93] Department of Energy (DOE), *Hydropower Vision: A New Chapter for America's First Renewable Electricity Source* (Oak Ridge, TN: DOE, 2016), https://energy.gov/sites/prod/files/2016/10/f33/HydropowerVision-10262016_0.pdf.

[94] R. Uria-Martinez, P. O'Connor, and M. Johnson, *2014 Hydropower Market Report* (Department of Energy, Wind and Water Power Technologies Office, April 2015), https://energy.gov/eere/water/downloads/2014-hydropower-market-report.

[95] J. Snell, D. Prowse, and K. Adams, "The Changing Role of Hydropower: From Cheap Local Energy Supply to Strategic Regional Resource," *International Journal of Water Resources Development* 30, no. 1 (2014): 121–134, http://dx.doi.org/10.1080/07900627.2013.860771.

[96] Department of Energy (DOE), *Hydropower Vision: A New Chapter for America's First Renewable Electricity Source* (Oak Ridge, TN: DOE, 2016), https://energy.gov/sites/prod/files/2016/10/f33/HydropowerVision-10262016_0.pdf.

[97] R. Uria-Martinez, P. O'Connor, and M. Johnson, *2014 Hydropower Market Report* (Department of Energy, Wind and Water Power Technologies Office, April 2015), https://energy.gov/eere/water/downloads/2014-hydropower-market-report.

[98] R. Uria-Martinez, P. O'Connor, and M. Johnson, "Hydropower Market Report: 2017 Update (April)," Oak Ridge National Laboratory, April 2017, https://energy.gov/eere/water/downloads/2014-hydropower-market-report.

[99] FERC, "Annual Charges," https://www.ferc.gov/industries/hydropower/annual-charges.asp

[100] U.S. Energy Information Administration (EIA), "Monthly Updated to the Annual Electric Generator Report," Form EIA-860m, March 2017, https://www.eia.gov/electricity/data/eia860m/

[101] Allen McFarland, "Total U.S. Energy Production Falls in 2016 after Six Consecutive Years of Increases," *Today in Energy*, Energy Information Administration, March, 31, 2017, https://www.eia.gov/todayinenergy/detail.php?id=30592.

[102] "Henry Hub Natural Gas Spot Price," Energy Information Administration, data from Thomson Reuters, last modified August 2, 2017, https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm.

[103] "Henry Hub Natural Gas Spot Price" Energy Information Administration, data from Thomson Reuters, last modified August 2, 2017, https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm.

[104] Energy Information Administration, *Trends in U.S. Oil and Natural Gas Upstream Costs* (Washington, DC: EIA, March 2016), 5, https://www.eia.gov/analysis/studies/drilling/pdf/upstream.pdf.

[105] Energy Information Administration (EIA), *Electric Power Monthly* (Washington, DC: EIA, May 2017), Table 6.7a, https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_6_07_a.

[106] SNL Energy, obtained by DOE using their database of electricity spot prices and Intercontinental Exchange natural gas spot prices taken from ABB's Energy Velocity Suite.

[107] Energy Information Administration, "Henry Hub Natural Gas Spot Price," Accessed July 2017, https://www.eia.gov/dnav/ng/hist/rngwhhdM.htm.

[108] Energy Information Administration (EIA), *Capital Cost Estimates for Utility Scale Electricity Generating Plants* (Washington, DC: EIA, November 2016), Table 1, https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capcost_assumption.pdf.

[109] "Assessment of Relative Benefit/Impact: Which Is the Best Generation Technology?" Electric Power Research Institute, http://sites.epri.com/refcard/comparison.html.

[110] Energy Information Administration (EIA), *Monthly Energy Review* (Washington, DC: EIA, July 2017), https://www.eia.gov/totalenergy/data/monthly/#electricity.

[111]Chinese University of Hong Kong, "Single Cycle Gas Turbine Power Plant," CLP Power Hong Kong Ltd. and the Hongkong Electric Co. Ltd., 2014, http://www.hk-phy.org/energy/power/elect_phy/flash/powerplant_e.html.

[112] Tyler Hodge, "Average Utilization for Natural Gas Combined-Cycle Plants Exceeded Coal Plants in 2015," *Today in Energy,* Energy Information Administration, April 4, 2016, https://www.eia.gov/todayinenergy/detail.php?id=25652.

[113] EPSA Analysis: Cara Marcy, Jeffrey Logan, James McCall, Francisco Flores-Espino, Aaron Bloom, Jørn Aabakken, Wesley Cole, Thomas Jenkins, Gian Porro, Chang Liu, et al., *Electricity Generation Baseline Report* (Golden, CO: National Renewable Energy Laboratory, October 2016), https://energy.gov/epsa/downloads/electricity-generation-baseline-report.

[114] Jaime López, "Combustion Engine vs Gas Turbine: Ramp Rate," Wärtsilä, accessed December 15, 2016, http://www.wartsila.com/energy/learning-center/technical-comparisons/combustion-engine-vs-gas-turbine-ramp-rate.

[115] International Energy Agency (IEA) Environmental Projects Ltd, *Operating Flexibility of Power Plants with CCS* (Cheltenham, UK: IEA Environmental Projects Ltd, June 2012), 14, http://hub.globalccsinstitute.com/sites/default/files/publications/104631/operating-flexibility-power-plants-ccs.pdf.

[116] Energy Information Administration (EIA), Monthly Energy Review (Washington, DC: EIA, June 2017), https://www.eia.gov/totalenergy/data/monthly/pdf/sec13_6.pdf. Data from EIA, "Form EIA-923: Power Plant Operations Report" and predecessor form(s), including "Form EIA-90: Power Plant Report," "Form EIA-920: Combined Heat and Power Plant Report," and "Form EIA-860: Annual Electric Generator Report."

[117] "Form EIA-860m: Preliminary Monthly Electric Generator Inventory," Energy Information Administration, March 2017, https://www.eia.gov/electricity/data/eia860m/.

Energy Information Administration (EIA), *Monthly Energy Review* (Washington, DC: EIA, July 2017), Table A6, https://www.eia.gov/totalenergy/data/monthly/pdf/sec13_6.pdf; data from "Form EIA-923: Power Plant Operations

Report" and predecessor form(s), including "Form EIA-906: Power Plant Report," "Form EIA-920: Combined Heat and Power Plant Report," and "Form EIA-860: Annual Electric Generator Report."

[118] "Form EIA-860m: Preliminary Monthly Electric Generator Inventory," Energy Information Administration, March 2017, https://www.eia.gov/electricity/data/eia860m/.

[119] "Form EIA-860m: Preliminary Monthly Electric Generator Inventory," Energy Information Administration, March 2017, https://www.eia.gov/electricity/data/eia860m/.

[120] Kristine Harmon and Daniel Shea, *State Options to Keep Nuclear Power in the Generation Mix* (Denver, CO: National Conference of State Legislatures, January 2017), http://www.ncsl.org/Portals/1/Documents/energy/StateOptions_NuclearPower_f05_WEB.pdf.

[121] "Administrative Consent Order in the Matter of Exelon Generation Company, LLC. Oyster Creek Generating Station," State of New Jersey Department of Environmental Protection, December 9, 2010, http://www.nj.gov/dep/barnegatbay/docs/aco_oyster.creek.pdf.

[122] Cooling Water Intake Rule, 79 Fed. Reg. 48299 (2014) (40 C.F.R. § 122, 125), https://www.federalregister.gov/documents/2014/08/15/2014-12164/national-pollutant-discharge-elimination-system-final-regulations-to-establish-requirements-for.

[123] "Memorandum: Clean Water Act Section 316(b) Regulations for Cooling Water Intake Structures at Existing Facilities: NPDES Permitting Process When Federally-Listed Threatened and Endangered Species and/or Designated Critical Habitat Are or May Be Present," Environmental Protection Agency, December 11, 2014, https://www.epa.gov/sites/production/files/2015-04/documents/cooling-water_esa-instructional-memo_12-11-2014.pdf.

[124] Cooling Water Intake Rule, 79 Fed. Reg. 48299 (2014) (40 C.F.R. § 122, 125), https://www.federalregister.gov/documents/2014/08/15/2014-12164/national-pollutant-discharge-elimination-system-final-regulations-to-establish-requirements-for

[125] "Cross-State Air Pollution Rule (CSAPR) Basics," Environmental Protection Agency, accessed October 13, 2016, https://www.epa.gov/csapr/cross-state-air-pollution-rule-csapr-basics.

[126] "Cross-State Air Pollution Rule (CSAPR) Basics," Environmental Protection Agency, accessed October 13, 2016, https://www.epa.gov/csapr/cross-state-air-pollution-rule-csapr-basics.

[127] Steam Electric Effluent Limitations Guidelines, 39 Fed. Reg. 8294 (1974) (40 C.F.R. § 423), https://www.epa.gov/eg/steam-electric-power-generating-effluent-guidelines-documents-related-1974-initial-rulemaking.

[128] Mercury and Air Toxics Standards, 77 Fed. Reg. 9304 (2012) (40 C.F.R. § 60, 63).

[129] "EPA Announces Mercury and Air Toxics Standards (MATS) for Power Plants – Technical Information," Environmental Protection Agency, December 21, 2011, https://www.epa.gov/mats/epa-announces-mercury-and-air-toxics-standards-mats-power-plants-technical-information.

[130] Coal Combustion Residuals Rule, 80 Fed. Reg. 21302 (2015) (40 C.F.R. § 257, 261).

[131] Carbon Pollution Emission Guidelines for Existing Stationary Sources, 80 Fed. Reg. 64662 (2015) (40 C.F.R. § 60).

[132] Fitch Ratings, *Time to Retire? U.S. Coal Plants in Environmental Crosshairs* (Fitch Ratings, February 28, 2011).

[133] ABB Ventyx Velocity Suite dataset. Accessed August 2017.

[134] The National Coal Council, *Reliable & Resilient, The Value of Our Existing Coal Fleet: An Assessment of Measures to Improve Reliability & Efficiency While Reducing Emissions* (Washington, DC: The National Coal Council, May 2014), 2–3, http://www.nationalcoalcouncil.org/reports/1407/NCCValueExistingCoalFleet.pdf.

[135] Fitch Ratings, *Time to Retire? U.S. Coal Plants in Environmental Crosshairs* (Fitch Ratings, February 28, 2011).

[136] Dale Probasco and Bob Ruhlman, "Coal-Fired Generation Cost and Performance Trends," *Power,* May 1, 2011, http://www.powermag.com/coal-fired-generation-cost-and-performance-trends/?pagenum=3.

[137] "27 Gigawatts of Coal-Fired Capacity to Retire over Next Five Years," *Today in Energy,* Energy Information Administration, July 27, 2012, https://www.eia.gov/todayinenergy/detail.php?id=7290.

[138] Michael Leff, "Coal-Fired Power Plant Operators Consider Emissions Compliance Strategies," *Today in Energy,* Energy Information Administration, March 28, 2014, https://www.eia.gov/todayinenergy/detail.php?id=15611.

[139] Sara Hoff and Jonathan DeVilbiss, "EIA Electricity Generator Data Show Power Industry Response to EPA Mercury Limits," *Today in Energy*, July 7, 2016, https://www.eia.gov/todayinenergy/detail.php?id=26972.

[140] James E. McCarthy, *EPA's Utility MACT: Will the Lights Go Out?* (Washington, DC: Congressional Research Service, January 9, 2012), R42144, 4, https://www.eenews.net/assets/2012/01/19/document_gw_03.pdf.

[141] Sara Hoff and Jonathan DeVilbiss, "EIA Electricity Generator Data Show Power Industry Response to EPA Mercury Limits," *Today in Energy*, July 7, 2016, https://www.eia.gov/todayinenergy/detail.php?id=26972.

[142] "New Source Review (NSR) Permitting," Environmental Protection Agency, accessed July 13, 2017, https://www.epa.gov/nsr.

[143] The National Coal Council, *Leveling the Playing Field: Policy Parity for Carbon Capture and Storage Technologies* (Washington, DC: The National Coal Council, November 2015), http://www.nationalcoalcouncil.org/studies/2015/Leveling-the-Playing-Field-for-Low-Carbon-Coal-Fall-2015.pdf

[144] The National Coal Council, *Reliable & Resilient, The Value of Our Existing Coal Fleet: An Assessment of Measures to Improve Reliability & Efficiency While Reducing Emissions* (Washington, DC: The National Coal Council, May 2014), 5, http://www.nationalcoalcouncil.org/reports/1407/NCCValueExistingCoalFleet.pdf.

[145] Environmental Protection Agency (EPA), *New Source Review: Report to the President* (EPA, June 2002), 1, https://www.epa.gov/sites/production/files/2015-08/documents/nsr_report_to_president.pdf.

[146] Steven F. Hayward, "Making Sense of 'New Source Review,'" American Enterprise Institute, July 1, 2003, http://www.aei.org/publication/making-sense-of-new-source-review/.

[147] Sue Tierney, "EPA Proposed Utility Air Toxics Rule—Managing Compliance in Reliable Ways," Congressional Staff Briefing, May 9, 2011, quoted in James McCarthy and Claudia Copeland, *EPA's Regulation of Coal-Fired Power: Is a "Train Wreck" Coming?* (Washington, DC: Congressional Research Service, August 8, 2011), AR-1162, https://www3.epa.gov/region1/npdes/merrimackstation/pdfs/ar/AR-1162.pdf.

[148] Energy Information Administration, "Update on Retirements of Coal-Fired Power Plants" (presented to Secretary Ernest Moniz, November 8, 2016).

[149] Guggenheim Securities, as reported in David Schlissel, *The Beginning of the End: Fundamental Changes in Energy Markets Are Undermining the Financial Viability of Coal-Fired Power Plants in Texas* (Institute for Energy Economics and Financial Analysis, September 2016), http://ieefa.org/wp-content/uploads/2016/09/The-Beginning-of-the-End_September-2016.pdf.

[150] U.S. Energy Information Administration, "Annual Energy Outlook 2014 with projections to 2040: Table A9. Electricity generating capacity (gigawatts)," April 2014, page A-20, https://www.eia.gov/outlooks/archive/aeo14/pdf/0383(2014).pdf.

[151] Energy Information Administration, "Update on Retirements of Coal-Fired Power Plants" (presented to Secretary Ernest Moniz, November 8, 2016).

[152] "Frequently Asked Questions: How Much Carbon Dioxide Is Produced When Different Fuels Are Burned?," Energy Information Administration, June 8, 2017, https://www.eia.gov/tools/faqs/faq.php?id=73&t=11.

[153] Warren Lasher, *Summary of Impacts of Environmental Regulations in the ERCOT Region* (Electric Reliability Council of Texas, March 31, 2015), https://www.ferc.gov/CalendarFiles/20150327133925-Lasher,%20ERCOT.pdf.

[154] Energy Information Administration (EIA), *Electric Power Annual 2015* (Washington, DC: EIA, 2016), Table 8.2, https://www.eia.gov/electricity/annual/html/epa_08_02.html.

[155] "Form EIA-860m: Preliminary Monthly Electric Generator Inventory," Energy Information Administration, March 2017, https://www.eia.gov/electricity/data/eia860m/.

[156] Kristine Harmon and Daniel Shea, "State Options to Keep Nuclear Power in the Generation Mix," NCSL, January 2017. http://www.ncsl.org/Portals/1/Documents/energy/StateOptions_NuclearPower_f05_WEB.pdf

[157] State of New Jersey Department of Environmental Protection, Administrative Consent Order In the Matter of Exelon Generation Company, LLC. Oyster Creek Generating Station, December 9, 2010. http://www.nj.gov/dep/barnegatbay/docs/aco_oyster.creek.pdf

[158] "Administrative Consent Order in the Matter of Exelon Generation Company, LLC. Oyster Creek Generating Station," State of New Jersey Department of Environmental Protection, December 9, 2010, http://www.nj.gov/dep/barnegatbay/docs/aco_oyster.creek.pdf.

[159] Sam Batkins, Philip Rossetti, and Dan Goldbeck, "Putting Nuclear Regulatory Costs in Context," American Action Forum, July 12, 2017, https://www.americanactionforum.org/research/putting-nuclear-regulatory-costs-context/.

[160] R. Uria-Martinez, P. O'Connor, and M. Johnson, "Hydropower Market Report: 2017 Update (April)," Oak Ridge National Laboratory, April 2017, https://energy.gov/eere/water/downloads/2014-hydropower-market-report.

[161] Aaron Levine, Katherine R. Young, and Kermit Witherbee, "Coordinating Permit Offices and the Development of Utility-Scale Geothermal Energy" (presented at the 2013 Geothermal Resources Council Annual Meeting, Las Vegas, NV, October 1, 2013), http://www.nrel.gov/docs/fy14osti/60276.pdf.

[162] U.S. Department of Energy (DOE), "2014 Hydropower Market Report," Prepared by Oak Ridge National Laboratory, April 2015, Page 44, https://energy.gov/sites/prod/files/2015/05/f22/2014%20Hydropower%20Market%20Report_20150512_rev6.pdf.

[163] Energy Information Administration (EIA), *Monthly Energy* Review (Washington, DC: EIA, June 2017), Table 7.2b, https://www.eia.gov/totalenergy/data/monthly/pdf/sec7_6.pdf.

[164] U.S. Department of Energy (DOE), *Wind Vision: A New Era for Wind Power in the United States* (DOE, 2015), https://www.energy.gov/sites/prod/files/WindVision_Report_final.pdf.

[165] April Lee, "U.S. Wind Generating Capacity Surpasses Hydro Capacity at the End of 2016," *Today in Energy,* Energy Information Administration, March 6, 2017, https://www.eia.gov/todayinenergy/detail.php?id=30212.

[166] April Lee, "U.S. Wind Generating Capacity Surpasses Hydro Capacity at the End of 2016," *Today in Energy,* Energy Information Administration, March 6, 2017, https://www.eia.gov/todayinenergy/detail.php?id=30212.

[167] Galen Barbose, *U.S. Renewables Portfolio Standards: 2016 Annual Status Report* (Lawrence Berkeley National Laboratory, April 2016), LBNL-1005057, https://emp.lbl.gov/sites/all/files/lbnl-1005057.pdf

[168] Galen Barbose, *U.S. Renewables Portfolio Standards: 2016 Annual Status Report* (Lawrence Berkeley National Laboratory, April 2016), LBNL-1005057, https://emp.lbl.gov/sites/all/files/lbnl-1005057.pdf.

[169] Ran Fu, Donald Chung, Travis Lowder, David Feldman, Kristen Ardani, and Robert Margolis, *U.S. Solar Photovoltaic System Cost Benchmark: Q1 2016* (Golden, CO: National Renewable Energy Laboratory, September 2016), NREL/TP-6A20-66532, Fig. ES-1, http://www.nrel.gov/docs/fy16osti/66532.pdf .

[170] Christopher Mone, Maureen Hand, Mark Bolinger, Joseph Rand, Donna Heimiller, and Jonathan Ho, *2015 Cost of Wind Energy Review* (Golden, CO: National Renewable Energy Laboratory, May 2017), NREL/TP-6A20-66861, Fig. 35, http://www.nrel.gov/docs/fy17osti/66861.pdf.

[171] Ryan H. Wiser and Mark Bolinger, *2015 Wind Technologies Market Report* (Department of Energy, August 2016), LBNL-1005951, https://emp.lbl.gov/publications/2015-wind-technologies-market-report.

[172] "Renewable Electricity Production Tax Credit (PTC)," Department of Energy, https://energy.gov/savings/renewable-electricity-production-tax-credit-ptc.

[173] "Business Energy Investment Tax Credit (ITC)," Department of Energy, https://energy.gov/savings/business-energy-investment-tax-credit-itc.

[174] "Form EIA-860m: Preliminary Monthly Electric Generator Inventory," Energy Information Administration, March 2017, https://www.eia.gov/electricity/data/eia860m/.

[175] Ryan Wiser, Andrew Mills, et al., *Impacts of Variable Renewable Energy on Bulk Power System Assets, Pricing and Costs*, June 2017 draft (Lawrence Berkeley National Laboratory, forthcoming).

[176] Ryan Wiser, Andrew Mills, et al., *Impacts of Variable Renewable Energy on Bulk Power System Assets, Pricing and Costs*, June 2017 draft (Lawrence Berkeley National Laboratory, forthcoming).

[177] Management Information Services, *Two Thirds of a Century and $1 Trillion+ U.S. Energy Incentives: Analysis of Federal Expenditures for Energy Development, 1950–2016* (Management Information Services, May 2017), https://www.nei.org/CorporateSite/media/filefolder/Backgrounders/White-Papers/EnergyIncentives-MISI-0517.pdf?ext=.pdf.

[178] BW Research, *U.S. Energy and Employment Report* (Washington, DC: Department of Energy, January 2017), https://energy.gov/sites/prod/files/2017/01/f34/2017%20US%20Energy%20and%20Jobs%20Report_0.pdf.

[179] BW Research, *U.S. Energy and Employment Report* (Washington, DC: Department of Energy, January 2017), https://energy.gov/sites/prod/files/2017/01/f34/2017%20US%20Energy%20and%20Jobs%20Report_0.pdf.

[180] The Solar Foundation (TSF), National Solar Jobs Census 2015 (Washington, DC: TSF, January 2016), http://www.thesolarfoundation.org/wp-content/uploads/2016/10/TSF-2015-National-Solar-Jobs-Census.pdf.

[181] Energy Information Administration (EIA),"May 2017 Monthly Energy Review," May 25, 2017, accessed: June 6, 2017, https://www.eia.gov/totalenergy/data/monthly/.

[182] Federal Reserve Bank of St. Louis, "Real Gross Domestic Product, Billions of Chained 2009 Dollars, Annual, Seasonally Adjusted Annual Rate," Federal Reserve Economic Data, May 26, 2017, accessed: June 6, 2017, https://fred.stlouisfed.org/series/GDPC1

[183] Energy Information Administration, "Annual Energy Outlook 2017," January 2017, https://www.eia.gov/outlooks/aeo/pdf/0383(2017).pdf.

[184] Energy Information Administration (EIA),"May 2017 Monthly Energy Review," May 25, 2017, accessed: June 6, 2017, https://www.eia.gov/totalenergy/data/monthly/.

[185] Federal Reserve Bank of St. Louis, "Real Gross Domestic Product, Billions of Chained 2009 Dollars, Annual, Seasonally Adjusted Annual Rate," Federal Reserve Economic Data, May 26, 2017, accessed: June 6, 2017, https://fred.stlouisfed.org/series/GDPC1.

[186] U.S. Congressional Budget Office (CBO), "January 2017 Baseline Forecast-Data Release (Calendar Year)," The Budget and Economic Outlook: 2017 to 2027, accessed: June 7, 2017, https://www.cbo.gov/publication/52370.

[187] U.S. Energy Information Administration (EIA), "Electricity Supply, Disposition, Prices, and Emissions," Annual Energy Outlook 2017, January 2017, accessed: June 7, 2017, https://www.eia.gov/outlooks/aeo/.

[188] Lisa C. Schwartz, Max Wei, William Morrow, Jeff Deason, Steven R. Schiller, Greg Leventis, Sarah Smith, et al. *Electricity End Uses, Energy Efficiency, and Distributed Energy Resources Baseline* (Berkeley, CA: Lawrence Berkeley National Laboratory, January 2017), https://energy.gov/epsa/downloads/electricity-end-uses-energyefficiency-and-distributed-energy-resources-baseline.

[189] Steve Nadel, Neal Elliott, and Therese Langer, *Energy Efficiency in the United States: 35 Years and Counting* (Washington, DC: American Council for an Energy-Efficient Economy, June 2015), Report E1502, 1–2, http://aceee.org/research-report/e1502.

[190] Hillard Huntington, *Structural Change and U.S. Energy Use: Recent Patterns* (Stanford, CA: Stanford University Energy Modeling Forum, July 2009), https://web.stanford.edu/group/emf-research/docs/occasional_papers/op65.pdf.

[191] Energy Information Agency (EIA), *Annual Energy Outlook Retrospective Review: Evaluation of 2014 and Prior Reference Case Projections* (Washington, DC: EIA, March 2015), Table 15, https://www.eia.gov/outlooks/aeo/retrospective/excel/table_15.xls. Original EIA file updated with AEO 2001 through 2016 electricity sales data from "Table 8. Electricity Supply, Disposition, Prices, and Emissions."

[192] Department of Energy (DOE), *Transforming the Nation's Electricity System: The Second Installment of The Quadrennial Energy Review* (Washington, DC: DOE, January 2017), S-7, https://www.energy.gov/sites/prod/files/2017/02/f34/Quadrennial%20Energy%20Review--Second%20Installment%20%28Full%20Report%29.pdf.

[193] Energy Information Administration (EIA), *Annual Energy Outlook 2017 with Projections to 2050* (Washington, DC: EIA, January 2017), No CPP Scenario Table 9, https://www.eia.gov/outlooks/aeo/tables_side.php.

[194] Energy Information Administration (EIA), *Annual Energy Outlook 2017 with Projections to 2050* (Washington, DC: EIA, January 2017), No CPP Scenario, https://www.eia.gov/outlooks/aeo/tables_side.php.

[195] PJM Interconnection, "PJM Provides the Following Documents and Information for the Department's Consideration as It Prepares Its Report in Response to the Secretary's Memorandum of April 14, 2017," sent by PJM Interconnection to the Department of Energy, May 3, 2017.

[196] Energy Information Administration analysis using ABB's Energy Velocity Suite collection of the Environmental Protection Agency's continuous emission monitoring system data.

[197] Postponement of Certain Compliance Dates for the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, 82 Fed. Reg. 26017 (proposed June 6, 2017) (to be codified at 40 C.F.R. § 423), https://www.regulations.gov/document?D=EPA-HQ-OW-2009-0819-6485.

[198] Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category; Extension of Public Comment Period, 78 Fed. Reg. 41907 (proposed July 12, 2013) (to be codified at 40 C.F.R. § 423), https://www.regulations.gov/document?D=EPA-HQ-OW-2009-0819-3132.

[199] Steam Electric Power Generating Effluent Guidelines – 2015 Final Rule, U.S. Environmental Protection Agency (EPA), https://www.epa.gov/eg/steam-electric-power-generating-effluent-guidelines-2015-final-rule.

[200] Utility Water Act Group, "Utility Water Act Group's Petition for Rulemaking to Reconsider and Administratively Stay the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category; Final Rule, 80 Fed. Reg. 67,838-903 (Nov. 3, 2015)," letter to Environmental Protection Agency Administrator Scott Pruitt, March 24, 2017,

https://www.epa.gov/sites/production/files/2017-03/documents/letter_to_epa_submitting_petition_for_reconsideration_w_exhibits-c_508.pdf.

[201] Environmental Protection Agency, *Economic Analysis for the Final Section 316(b) Existing Facilities Rule* (Washington, DC: EPA, May 2014), EPA-821-R-14-001, https://www.epa.gov/sites/production/files/2015-05/documents/cooling-water_phase-4_economics_2014.pdf.

[202] Warren Lasher, *Summary of Impacts of Environmental Regulations in the ERCOT Region* (Electric Reliability Council of Texas, March 31, 2015), https://www.ferc.gov/CalendarFiles/20150327133925-Lasher,%20ERCOT.pdf.

[203] SNL Energy, "SNL Day-Ahead Prices," accessed June 15, 2017, subscription service; ABB Velocity Suite, "Daily Power Prices," accessed June 15, 2017, subscription service.

[204] "Final Rule: Disposal of Coal Combustion Residuals from Electric Utilities," Environmental Protection Agency, accessed June 30, 2017, https://www.epa.gov/coalash/coal-ash-rule.

[205] 80 Fed. Reg. 74 (2015) (40 C.F.R. § 257, 261), https://www.gpo.gov/fdsys/pkg/FR-2015-04-17/pdf/2015-00257.pdf.

[206] "Map of States Covered by CSAPR," Environmental Protection Agency, https://www.epa.gov/airmarkets/map-states-covered-csapr.

[207] "Visibility – Regulatory Actions," Environmental Protection Agency, https://www.epa.gov/visibility/visibility-regulatory-actions.

[208] "Visibility and Haze – Rules and Regulations" *Federal Register* 77, no. 110 (June 7, 2012): 33642. https://www.epa.gov/visibility/final-action-address-regional-haze-2012.

[209] John Larsen (analyst, Rhodium Group), cited in Benjamin Storrow, "Big, Young Coal Plants Are Closing. Is It a New Trend?," *E&E News*, April 27, 2017, https://www.eenews.net/stories/1060053677.

[210] Department of Energy (DOE), *Hydropower Vision: A New Chapter for America's First Renewable Electricity Source* (Oak Ridge, TN: DOE, 2016), https://energy.gov/sites/prod/files/2016/10/f33/Hydropower-Vision-10262016_0.pdf.

[211] R. Uria-Martinez, P. O'Connor, and M. Johnson, "Hydropower Market Report: 2017 Update (April)," Oak Ridge National Laboratory, April 2017, https://energy.gov/eere/water/downloads/2014-hydropower-market-report.

[212] National Academies of Sciences, Engineering, and Medicine. 2017. Enhancing the Resilience of the Nation's Electricity System. Washington, DC: The National Academies Press. https://doi.org/10.17226/24836

[213] Department of Energy (DOE), *Transforming the Nation's Electricity System: The Second Installment of The Quadrennial Energy Review* (Washington, DC: DOE, January 2017), p.S-4, https://www.energy.gov/sites/prod/files/2017/02/f34/Quadrennial%20Energy%20Review--Second%20Installment%20%28Full%20Report%29.pdf.https://www.energy.gov/sites/prod/files/2017/02/f34/Quadrennial%20Energy%20Review%20Summary%20for%20Policymakers.pdf

[214] Gerry Cauley (president and CEO, North American Electric Reliability Corporation), letter to Energy Secretary Rick Perry, May 9, 2017.

[215] Department of Energy (DOE), *Transforming the Nation's Electricity System: The Second Installment of The Quadrennial Energy Review* (Washington, DC: DOE, January 2017),p. https://www.energy.gov/sites/prod/files/2017/02/f34/Quadrennial%20Energy%20Review--Second%20Installment%20%28Full%20Report%29.pdf..https://www.energy.gov/sites/prod/files/2017/02/f34/Quadrennial%20Energy%20Review%20Summary%20for%20Policymakers.pdf

[216] Gerry Cauley (president and CEO, North American Electric Reliability Corporation), letter to Energy Secretary Rick Perry, May 9, 2017.

[217] Gerry Cauley, "Remarks of Gerry Cauley, President and CEO, North American Electric Reliability Corporation," (presented at Federal Energy Regulatory Commission Reliability Technical Conference, Panel I: Overview on the State of Reliability, June 22, 2017), https://www.ferc.gov/CalendarFiles/20170717080645-Cauley,%20NERC.pdf.

[218] Severe Impact Resilience Task Force, *Severe Impact Resilience: Considerations and Recommendations* (North American Electric Reliability Corporation, May 2012), http://www.nerc.com/comm/OC/SIRTF%20Related%20Files%20DL/SIRTF_Final_May_9_2012-Board_Accepted.pdf.

[219] North American Electric Reliability Corporation (NERC), *State of Reliability 2017* (Atlanta, GA: NERC, June 2017), http://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/SOR_2017_MASTER_20170613.pdf.

[220] Federal Energy Regulatory Commission, communication with Department of Energy, July 2017.

[221] Gerry Cauley, "Written Statement of Gerry Cauley, President and CEO, North American Electric Reliability Corporation, to the Quadrennial Energy Review Task Force" (public comment presented at *Transforming the Nation's Electricity System: Second Installment of the Quadrennial Energy Review,* Public Meeting No. 1, Washington, DC, February 4, 2016), https://www.energy.gov/epsa/downloads/qer-second-installment-public-meeting-washington-dc.

[222] Thomas Burgess and Gerry Cauley, "Remarks of Thomas Burgess, Vice President and Director of Reliability Assessment and Performance Analysis, and Gerry Cauley, President and CEO, North American Electric Reliability Corporation" (presented at Federal Energy Regulatory Commission Reliability Technical Conference, Panel II: Emerging Issues, June 10, 2014), http://www.nerc.com/news/testimony/Testimony%20and%20Speeches/Panel%202%20-%20Cauley%20Burgess.pdf.

[223] Mark Lauby and John Moura, "Remarks of Mark G. Lauby, Senior Vice President and Chief Reliability Officer, and John Moura, Director, Reliability Assessment and System Analysis" (presented at Federal Energy Regulatory Commission Reliability Technical Conference, Panel II: Emerging Issues, June 4, 2015), http://www.nerc.com/news/testimony/Testimony%20and%20Speeches/FERC%20Technical%20Conference%20June%204%202015%20Lauby%20Moura%20Panel%20II.pdf.

[224] Mark Lauby, "Remarks of Mark Lauby, Senior Vice President and Chief Reliability Officer, North American Electric Reliability Corporation" (presented at Federal Energy Regulatory Commission Reliability Technical Conference, Panel II: Emerging Issues, June 1, 2016), http://www.nerc.com/news/testimony/Documents/Lauby.pdf.

[225] Mark Lauby, "Remarks of Mark Lauby, Senior Vice President and Chief Reliability Officer, North American Electric Reliability Corporation" (presented at Federal Energy Regulatory Commission Reliability Technical Conference, Panel III: The Potential for Long-term and Large-Scale Disruptions to the Bulk-Power System, June 22, 2017), https://www.ferc.gov/CalendarFiles/20170717080646-Lauby,%20NERC.pdf.

[226] North American Electric Reliability Corporation (NERC), *State of Reliability 2017* (Atlanta, GA: NERC, June 2017), http://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/SOR_2017_MASTER_20170613.pdf.

[227] "Essential Reliability Services Working Group (ERSWG) and Distributed Energy Resources Task Force (DERTF)," North American Electric Reliability Corporation, http://www.nerc.com/comm/Other/Pages/Essential-Reliability-Services-Task-Force-(ERSTF).aspx.

[228] "Integration of Variable Generation Task Force (IVGTF)," North American Electric Reliability Corporation, http://www.nerc.com/comm/PC/Pages/Integration%20of%20Variable%20Generation%20Task%20Force%20(IVGTF)/Integration-of-Variable-Generation-Task-Force-IVGTF.aspx.

[229] Gerry Cauley (president and CEO, North American Electric Reliability Corporation), letter to Energy Secretary Rick Perry, May 9, 2017.

[230] North American Electric Reliability Corporation, staff analysis requested by Department of Energy, June 2017.

[231] North American Electric Reliability Corporation, modified from 2016 Long-Term Reliability Assessment, requested by Department of Energy, June 2017.

[232] Noha Abdel-Karim and David Calderon, "Impact of Wind and Solar Variability on the Resource Adequacy for North American Bulk Power System," NERC, 2016, http://ieeexplore.ieee.org/document/7764176/?reload=true.

[233] Department of Energy (DOE), *Maintaining Reliability in the Modern Power System* (Washington, DC: DOE, 2016), https://energy.gov/sites/prod/files/2017/01/f34/Maintaining%20Reliability%20in%20the%20Modern%20Power%20System.pdf.

[234] North American Electric Reliability Corporation (NERC), *Methods to Model and Calculate Capacity for Contributions of Variable Generation for Resource Adequacy Planning* (Princeton, NJ: NERC, March 2011), http://www.nerc.com/files/ivgtf1-2.pdf.

[235] NERC, "Balancing and Frequency Control – A Technical Document Prepared by the NERC Resources Subcommittee, January 2011, Accessed August 2017 http://www.nerc.com/docs/oc/rs/NERC%20Balancing%20and%20Frequency%20Control%20040520111.pdf

[236] North American Electric Reliability Corporation (NERC), *Essential Reliability Services Task Force Measures Framework Report* (Atlanta, GA: NERC, November 2015), http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSTF%20Framework%20Report%20-%20Final.pdf.

[237] North American Electric Reliability Corporation (NERC), *Essential Reliability Services Task Force Measures Framework Report* (Atlanta, GA: NERC, November 2015), http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSTF%20Framework%20Report%20-%20Final.pdf.

[238] Federal Energy Regulatory Commission (FERC), *Reliability Primer* (Washington, DC: FERC, December 2016), 15, https://www.ferc.gov/legal/staff-reports/2016/reliability-primer.pdf.

[239] Reactive Power Requirements for Non-Synchronous Generation, 40 C.F.R. § 35 (June 16, 2016), https://ferc.gov/whats-new/comm-meet/2016/061616/E-1.pdf.

[240] Essential Reliability Services and the Evolving Bulk-Power System—Primary Frequency Response, 18 C.F.R. § 35 (proposed November 17, 2016), https://www.ferc.gov/whats-new/comm-meet/2016/111716/E-3.pdf.

[241] NERC, "Balancing and Frequency Control – A Technical Document Prepared by the NERC Resources Subcommittee, January 2011, Accessed August 2017 http://www.nerc.com/docs/oc/rs/NERC%20Balancing%20and%20Frequency%20Control%20040520111.pdf

[242] NERC, "Balancing and Frequency Control – A Technical Document Prepared by the NERC Resources Subcommittee, January 2011, Accessed August 2017 http://www.nerc.com/docs/oc/rs/NERC%20Balancing%20and%20Frequency%20Control%20040520111.pdf

[243] Joseph H. Eto, John Undrill, Peter Mackin, Ron Daschmans, Ben Williams, Brian Haney, Randall Hunt, Jeff Ellis, Howard Illian, et al., *Use of Frequency Response Metrics to Assess the Planning and Operating Requirements for Reliable Integration of Variable Renewable Generation* (Berkeley, CA: Lawrence Berkeley National Laboratory, December 2010)**,** LBNL-4142E**,** https://www.ferc.gov/industries/electric/indus-act/reliability/frequencyresponsemetrics-report.pdf**.**

[244] Joseph H. Eto, John Undrill, Peter Mackin, Ron Daschmans, Ben Williams, Brian Haney, Randall Hunt, Jeff Ellis, Howard Illian, et al., *Use of Frequency Response Metrics to Assess the Planning and Operating Requirements for Reliable Integration of Variable Renewable Generation* (Berkeley, CA: Lawrence Berkeley National Laboratory, December 2010), LBNL-4142E, https://www.ferc.gov/industries/electric/indus-act/reliability/frequencyresponsemetrics-report.pdf.

[245] North American Electric Reliability Corporation (NERC), *Essential Reliability Services Task Force (ERSTF) Scope* (Washington, DC: NERC, 2014), http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/Scope_ERSTF_Final. pdf.

[246] Frequency Regulation Compensation in the Organized Wholesale Power Markets, 18 C.F.R. § 35 (October 20, 2011), https://www.ferc.gov/whats-new/comm-meet/2011/102011/E-28.pdf.

[247] PJM Interconnection, *Appendix to PJM's Evolving Resource Mix and System Reliability* (PJM Interconnection, March 30, 2017), http://www.pjm.com/~/media/library/reports-notices/special-reports/20170330-appendix-to-pjms-evolving-resource-mix-and-system-reliability.ashx.

[248] Debra Lew of GE Energy Consulting, e-mail message to author(s), May 31, 2017

[249] General Electric, "Impact of Frequency Responsive Wind Plant Controls on Grid Performance. Last modified December 20, 2010. http://web.mit.edu/windenergy/windweek/Presentations/GE%20Impact%20of%20Frequency%20Responsive%20Wind%20Plant%20Controls%20Pres%20and%20Paper.pdf

[250] M Kinterner-Meyer, J Homer, P Balducci, M Weimar, I Shavel, M Hagerty, N Powers, Y Yang, R Lueken, "Valuation of Electric Power System Services and Technologies," Pacific Northwest National Lab and The Brattle Group, August 2016, http://www.brattle.com/system/publications/pdfs/000/005/389/original/Valuation_of_Electric_Power_System_Services_and_Technologies.pdf?1484183040

[251] "FERC Proposes to Integrate Electricity Storage into Organized Markets," Federal Energy Regulatory Commission, November 17, 2016, https://www.ferc.gov/media/news-releases/2016/2016-4/11-17-16-E-1.asp#.WYHpMaqWyUk.

[252] Imre Gyuk, Mark Johnson, John Vetrano, Kevin Lynn, William Parks, Rachna Handa, Landis Kannberg, Sean Hearne, Karen Waldrip, and Ralph Braccio, *Grid Energy Storage* (Department of Energy, December 2013), Table 5, https://energy.gov/sites/prod/files/2014/09/f18/Grid%20Energy%20Storage%20December%202013.pdf.

[253] Imre Gyuk, Mark Johnson, John Vetrano, Kevin Lynn, William Parks, Rachna Handa, Landis Kannberg, Sean Hearne, Karen Waldrip, and Ralph Braccio, *Grid Energy Storage* (Department of Energy, December 2013), Table 5, https://energy.gov/sites/prod/files/2014/09/f18/Grid%20Energy%20Storage%20December%202013.pdf.

[254] Enerknol Research, "New York to Set Energy Storage Targets by Next Year", June 2017, Accessed August, 2017 https://enerknol.com/wp-content/uploads/2017/06/EKR-PU-New-York-Energy-Storage-Legislation-6-30-2017.pdf

[255] Utility Dive, "New York expected to set high bar for energy storage after target bill passage", June 2017, Accessed August 2017, http://www.utilitydive.com/news/new-york-expected-to-set-high-bar-for-energy-storage-after-target-bill-pass/445845/

[256] U.S. Department of Energy (DOE), "Annual U.S. Transmission Data Review", October 2016, Accessed August 2017, https://www.energy.gov/sites/prod/files/2017/04/f34/Annual%20US%20Transmission%20Data%20Review%202016_0.pdf.

[257] Southwest Power Pool, *The Value of Transmission* (Southwest Power Pool, January 2016), https://spp.org/value-of-transmission/.

[258] "Order No. 1000 – Transmission Planning and Cost Allocation," Federal Energy Regulatory Commission, last modified October 26, 2016, https://www.ferc.gov/industries/electric/indus-act/trans-plan.asp.

[259] Federal Energy Regulatory Commission (FERC), "Competitive Transmission Development Rates (Docket No. AD16-18-000)" (FERC Technical Conference, June 27–28, 2016), https://www.ferc.gov/EventCalendar/EventDetails.aspx?ID=8285&CalType=&CalendarID=116&Date=06/27/2016&View=Listview.

[260] Rory Sweeney, "Five Years Later, FERC Takes Another Look at Order 1000," *RTO Insider*, July 4, 2016, https://www.rtoinsider.com/ferc-takes-another-look-order-1000-28637/.

[261] Corina Rivera Linares, "FERC Order 1000 Is Working Slowly, But It Is Working," *Electric Light & Power*, November 29, 2016, http://www.elp.com/articles/2016/11/ferc-order-1000-is-working-slowly-but-it-is-working.html.

[262] James Hoecker, "Making the Grid Great Again," *Public Utilities Fortnightly 2.0*, June 15, 2017, http://www.wiresgroup.com/docs/PUF2_0_June15_2017.pdf.

[263] Reiten, Patrick. "Oral Remarks of Patrick Reiten, President & CEO, Pacific Power, to the Quadrennial Energy Review Task Force" (at Energy Transmission, Storage, and Distribution Infrastructure: First Installment of the Quadrennial Energy Review, Public Meeting No. 5, Portland, OR, July 11, 2014), pp. 41-43 of transcript, https://www.energy.gov/sites/prod/files/2014/08/f18/transcript_portland_qer.pdf.

[264] Hoecker, James. "Making the Grid Great Again," *Public Utilities Fortnightly 2.0*, p. 16, June 15, 2017, http://www.wiresgroup.com/docs/PUF2_0_June15_2017.pdf.

[265] Cauley, Gerry. "Written Statement of Gerry Cauley, President and CEO, North American Electric Reliability Corporation, to the Quadrennial Energy Review Task Force,'' (public comment presented at *Transforming the Nation's Electricity System: Second Installment of the Quadrennial Energy Review,* Public Meeting No. 1, Washington, DC, February 4, 2016), p. 8, https://www.energy.gov/epsa/downloads/qer-second-installment-public-meeting-washington-dc.

[266]Midcontinent Independent System Operator, Multi Value Project Portfolio Analysis webpage, https://www.misoenergy.org/Planning/TransmissionExpansionPlanning/Pages/MVPAnalysis.aspx

[267]Southwest Power Pool, "FERC Approves Highway/Byway Cost Allocation Methodology," The Org Report, https://www.spp.org/documents/12559/07_10_july_org_report.pdf

[268] Federal Energy Regulatory Commission (FERC), Order Denying In Part and Granting In Part Rehearing, Conditionally Accepting Compliance Filing, and Directing Further Compliance Filings, Docket Nos. ER10-1791-001 and ER10-1791-002, (Washington, DC: FERC, October 21, 2011), p. 7, https://www.ferc.gov/whats-new/comm-meet/2011/102011/E-11.pdf.

[269] SPP Regional State Committee, Cost Allocation Working Group, "New Member Cost AllocationReview Process," October 26, 2016, https://spp.org/documents/47372/spp%20new%20member%20cost%20allocation%20review%20process%20-%20rsc%20approved%2020161024.pdf.

[270] Edison Electric Institute, *Transmission Projects: At A Glance* (Edison Electric Institute, December 2016), v, http://www.eei.org/issuesandpolicy/transmission/Documents/Trans_Project_lowres_bookmarked.pdf.

[271] Energy Information Administration (EIA), *Monthly Energy Review* (Washington, DC: EIA, June 2017), Table 7.2b, https://www.eia.gov/totalenergy/data/monthly/pdf/sec7_6.pdf; EIA, *Annual Energy Outlook 2017 with Projections to 2050* (Washington, DC: EIA, January 2017), https://www.eia.gov/outlooks/aeo/tables_side.php.

[272] Tosha Beckford, "Wind Turbines Provide 8% of U.S. Generating Capacity, More Than Any Other Renewable Source," *Today in Energy*, Energy Information Administration, May 2, 2017, https://www.eia.gov/todayinenergy/detail.php?id=31032.

[273] Gavin Bade and Robert Walton, "CAISO: Renewables Served 42% of California Demand on May 16, Setting Record," *Utility Dive*, May 18, 2017, http://www.utilitydive.com/news/caiso-renewables-served-42-of-california-demand-on-may-16-setting-record/442926/.

[274] Electric Reliability Council of Texas (ERCOT), *Inside the Promise: 2016 State of the Grid Report* (ERCOT, 2017), http://www.ercot.com/content/wcm/lists/114739/2016_StateoftheGridReport.pdf.

[275] Tom Kleckner, "ERCOT Reaches 50% Wind Penetration Mark," *RTO Insider*, March 26, 2017, https://www.rtoinsider.com/ercot-wind-penetration-40749/.

[276] Derek Wingfield, "SPP Sets North American Record for Wind Power," Southwest Power Pool, February 13, 2017, https://www.spp.org/about-us/newsroom/spp-sets-north-american-record-for-wind-power/.

[277] "Hourly Aggregated Wind Output – 2016," Electric Reliability Council of Texas, http://mis.ercot.com/misapp/GetReports.do?reportTypeId=13424&reportTitle=Hourly%20Aggregated%20Wind%20Output&showHTMLView=&mimicKey.

[278] Adapted by AWEA from EIA, Monthly net electricity generation for all sectors, 2017, accessed at: http://www.awea.org/MediaCenter/pressrelease.aspx?ItemNumber=9999.

[279] Jaquelin Cochran, Paul Denholm, Bethany Speer, and Mackay Miller, *Grid Integration and the Carrying Capacity of the U.S. Grid to Incorporate Variable Renewable Energy* (Golden, CO: National Renewable Energy Laboratory, April 2015), NREL/TP-6A20-62607, http://www.nrel.gov/docs/fy15osti/62607.pdf.

[280] Ryan Wiser, Andrew Mills, et al., *Impacts of Variable Renewable Energy on Bulk Power System Assets, Pricing and Costs*, June 2017 draft (Lawrence Berkeley National Laboratory, forthcoming).

[281] Jaquelin Cochran, Mackay Miller, Owen Zinaman, Michael Milligan, Doug Arent, Bryan Palmintier, Mark O'Malley, et al., *Flexibility in 21st Century Power Systems* (Golden, CO: National Renewable Energy Laboratory, May 2014), NREL/TP-6A20-61721, http://www.nrel.gov/docs/fy14osti/61721.pdf.

[282] Tian Tian and Ilya Chernyakhovskiy, "Forecasting Wind and Solar Generation: Improving System Operations", last modified January 2016. https://www.nrel.gov/docs/fy16osti/65728.pdf

[283] Bonneville Power Administration, communication with Department of Energy staff, July 2017.

[284] Bonneville Power Administration, communication with Department of Energy staff, July 2017.

[285] Bonneville Power Administration, communication with Department of Energy staff, July 2017.

[286] EnerNex, *NSP Wind Integration Study* (Minneapolis, MN: Xcel Energy, August 2014), 4, https://www.xcelenergy.com/staticfiles/xe/PDF/Regulatory/16-App-M-NSP-Wind-Integration-Study-January-2015.pdf.

[287] Mickey Francis, "Monthly Renewable Electricity Generation Surpasses Nuclear for the First Time Since 1984," *Today in Energy*, Energy Information Administration, July 6, 2017, https://www.eia.gov/todayinenergy/detail.php?id=31932.

[288] Owen Comstock, "Wind and Solar in March Accounted for 10% of U.S. Electricity Generation for the First Time," *Today in Energy*, Energy Information Administration, June 14, 2017, https://www.eia.gov/todayinenergy/detail.php?id=31632.

[289] Mark Gabriel (Administrator, Western Area Power Administration), "Study Examining Electricity Markets and Reliability," memorandum for Travis Fisher, May 18, 2017.

[290] Gwen Bredehoeft and Eric Krall, "Increased Solar and Wind Electricity Generation in California Are Changing Net Load Shapes," *Today in Energy*, Energy Information Administration, December 9, 2014, https://www.eia.gov/todayinenergy/detail.php?id=19111.

[291] Kendall Bowman (vice president regulatory affairs and policy, Duke Energy Corporation), "Comments of Duke Energy Corporation to the Federal Energy Regulatory Commission's Technical Conference Concerning Implementation Issues Under the Public Utility Regulatory Policies Act of 1978 ("PURPA"), Docket No. AD16-16-000," letter to Federal Energy Regulatory Commission Secretary Kimberly D. Bose, June 7, 2016, https://www.ferc.gov/CalendarFiles/20160617152411-Bowman,%20Duke%20Energy%20-%20Long%20paper.pdf.

[292] "What the duck curve tells us about managing a green grid," California ISO, 2016, http://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf.

[293] North American Electric Reliability Corporation (NERC), *2016 Long-Term Reliability Assessment* (Atlanta, GA: NERC, December 2016), http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2016%20Long-Term%20Reliability%20Assessment.pdf.

[294] North American Electric Reliability Corporation (NERC), *1,200 MW Fault-Induced Solar Photovoltaic Resource Interruption Disturbance Report: Southern California 8/16/2016 Event* (Atlanta, GA: NERC, June 2017), 4, http://www.nerc.com/pa/rrm/ea/1200_MW_Fault_Induced_Solar_Photovoltaic_Resource_/1200_MW_Fault_Induced_Solar_Photovoltaic_Resource_Interruption_Final.pdf.

[295] North American Electric Reliability Corporation (NERC), *1,200 MW Fault-Induced Solar Photovoltaic Resource Interruption Disturbance Report: Southern California 8/16/2016 Event* (Atlanta, GA: NERC, June 2017), 4, http://www.nerc.com/pa/rrm/ea/1200_MW_Fault_Induced_Solar_Photovoltaic_Resource_/1200_MW_Fault_Induced_Solar_Photovoltaic_Resource_Interruption_Final.pdf.

[296] North American Electric Reliability Corporation (NERC), *1,200 MW Fault-Induced Solar Photovoltaic Resource Interruption Disturbance Report: Southern California 8/16/2016 Event* (Atlanta, GA: NERC, June 2017),

http://www.nerc.com/pa/rrm/ea/1200_MW_Fault_Induced_Solar_Photovoltaic_Resource_/1200_MW_Fault_Induced_Solar_Photovoltaic_Resource_Interruption_Final.pdf.

[297] Australian Energy Market Operator (AEMO), *Black System South Australia, Final Report* (Melbourne, Australia: AEMO, March 2017), https://www.aemo.com.au/-/media/Files/Electricity/NEM/Market_Notices_and_Events/Power_System_Incident_Reports/2017/Integrated-Final-Report-SA-Black-System-28-September-2016.pdf.

[298] Australian Energy Market Operator (AEMO), *Black System South Australia, Final Report* (Melbourne, Australia: AEMO, March 2017), https://www.aemo.com.au/-/media/Files/Electricity/NEM/Market_Notices_and_Events/Power_System_Incident_Reports/2017/Integrated-Final-Report-SA-Black-System-28-September-2016.pdf.

[299] Jens C. Boemer, Karsten Burges, Pavel Zolotarev, Joachim Lehner, Patrick Wajant, Markus Furst, Rainer Brohm, and Thomas Kumm, "Overview of German Grid Issues and Retrofit of Photovoltaic Power Plants in Germany for the Prevention of Frequency Stability Problems in Abnormal System Conditions of the ENTSO-E Region Continental Europe" (presented at 1st International Workshop on Integration of Solar Power into Power Systems, Aarhus, Denmark, October 2011), http://www.ecofys.com/files/files/ecofys_2011_paper_on_frequency_stability_challenge.pdf.

[300] VDE, *Power Generation Systems Connected to the Low-Voltage Distribution Network* (VDE, 2011), VDE-AR-N 405, https://shop.vde.com/download/sample/700.

[301] PJM Interconnection, *PJM's Evolving Resource Mix and System Reliability* (PJM Interconnection, March 30, 2017), http://www.pjm.com/~/media/library/reports-notices/special-reports/20170330-pjms-evolving-resource-mix-and-system-reliability.ashx.

[302] E. Ela and U. Helman, *Wholesale Electricity Market Design Initiatives in the United States: Survey and Research Needs* (Palo Alto, CA: Electric Power Research Institute, 2016), https://www.epri.com/#/pages/product/000000003002009273/.

[303] Elena Verdolini, Francesco Vona, and David Popp, *Bridging the Gap: Do Fast Reacting Fossil Technologies Facilitate Renewable Energy Diffusion?* (Cambridge, MA: National Bureau of Economic Research, July 2016), Working Paper No. 22454, http://www.nber.org/papers/w22454, as quoted in Department of Energy (DOE), *Transforming the Nation's Electricity System: The Second Installment of the Quadrennial Energy Review* (Washington, DC: DOE, January 2017), https://www.energy.gov/sites/prod/files/2017/02/f34/Quadrennial%20Energy%20Review--Second%20Installment%20%28Full%20Report%29.pdf.

[304] Clyde Loutan, Peter Klauer, Sirajul Chowdhury, Stephen Hall, Mahesh Morjaria, Vladimir Chadliev, Nick Milam, Christopher Milan, and Vahan Gevorgian, *Demonstration of Essential Reliability Services by a 300-MW Solar Photovoltaic Power Plant* (Golden, CO: National Renewable Energy Laboratory, March 2017), NREL/TP-5D00-67799, http://www.nrel.gov/docs/fy17osti/67799.pdf.

[305] North American Electric Reliability Corporation (NERC), *Essential Reliability Services Task Force,* (Atlanta, GA: NERC, October 2014), http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSTF%20Concept%20Paper.pdf.

[306] Peter Alstone, Jennifer Potter, Mary Ann Piette, Peter Schwartz, Michael A. Berger, Laurel N. Dunn, Sarah J. Smith, et al., *Final Report on Phase 2 Results: 2015 California Demand Response Potential Study – Charting California's Demand Response Future* (Berkeley, CA: Lawrence Berkeley National Laboratory, November 2016), http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442451541.

[307] T. Markel, A. Meintz, K. Hardy, B. Chen, T. Bohn, J. Smart, D. Scoffield, et al., *Multi-Lab EV Smart Grid Integration Requirements Study Providing Guidance on Technology Development and Demonstration* (Golden, CO: National Renewable Energy Laboratory, May 2015), NREL/TP-5400-63963, http://www.nrel.gov/docs/fy15osti/63963.pdf.

[308] PJM Interconnection, *Appendix to PJM's Evolving Resource Mix and System Reliability* (PJM Interconnection, March 30, 2017), http://www.pjm.com/~/media/library/reports-notices/special-reports/20170330-appendix-to-pjms-evolving-resource-mix-and-system-reliability.ashx.

[309] PJM Interconnection, *Appendix to PJM's Evolving Resource Mix and System Reliability* (PJM Interconnection, March 30, 2017), http://www.pjm.com/~/media/library/reports-notices/special-reports/20170330-appendix-to-pjms-evolving-resource-mix-and-system-reliability.ashx.

[310] Energy Information Administration (EIA) *Electric Power Monthly* (Washington, DC: EIA, June 2017), https://www.eia.gov/electricity/monthly/.

[311] Devin Hartman, "Why Risk and Reliability Matter More than Fuel Diversity," *R Street Shorts No. 39*, May 2017, https://www.rstreet.org/wp-content/uploads/2017/05/RSTREETSHORT39.pdf.

[312] Federal Energy Regulatory Commission (FERC), "FERC Looks at Fuel Assurance Issues Following Technical Conferences," November 2014, https://www.ferc.gov/media/news-releases/2014/2014-4/11-20-14-E-2.asp#.WYnsJ6qWyUk.

[313] Federal Energy Regulatory Commission, "Decision: Docket Nos. AD13-7-000 and AD14-8-000 ," November 2014, Page 2, https://www.ferc.gov/whats-new/comm-meet/2014/112014/E-2.pdf

[314] North American Electric Reliability Corporation (NERC), *State of Reliability Report 2017* (Atlanta, GA: NERC, June 2017), http://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/SOR_2017_MASTER_20170613.pdf.

[315] NYSRC I-R3: Loss of Generator Gas Supply (New York City); see also *Con Edison Dual Fuel Interconnection Requirement* for LDC-interconnected generators.

[316] S&P Global Market Intelligence, "ISO New England's Van Welie Warns Energy Crunch, Green Push Could Lead to Blackouts: Exclusive Interview," October 10, 2016, SNL, https://www.snl.com/web/client?auth=inherit#news/article?id=37939124&KPLT=6&s_data=si%3D8%26kpa%3D1ad56e55-7f17-4bee-b433-a9418c56e545%26sa%3D.

[317] ISO New England, "Winter Program Payment Rate", accessed August 2017, https://www.iso-ne.com/markets-operations/markets/winter-program-payment-rate

[318] Gerry Cauley (president and CEO, North American Electric Reliability Corporation), letter to Energy Secretary Rick Perry, May 9, 2017.

[319] Gerry Cauley (president and CEO, North American Electric Reliability Corporation), letter to Energy Secretary Rick Perry, May 9, 2017.

[320] North American Electric Reliability Corporation (NERC), *Short-Term Special Assessment: Operational Risk Assessment with High Penetration of Natural Gas-Fired Generation* (Atlanta, GA: NERC, May 2016), http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC%20Short-Term%20Special%20Assessment%20Gas%20Electric_Final.pdf.

[321] North American Electric Reliability Corporation (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* (Washington, DC: NERC, May 2013), http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_PhaseII_FINAL.pdf.

[322] Justin Adder, *The Role of Natural Gas Storage in Maintaining Reliability of the Electric Power System* (National Energy Technology Laboratory, August 2016), https://www.netl.doe.gov/research/energy-analysis/search-publications/vuedetails?id=1824.

[323] Thomas S. Popik, "Testimony of the Foundation for Resilient Societies" (remarks presented at 2017 Federal Energy Regulatory Commission Reliability Technical Conference, June 22, 2017), https://www.ferc.gov/CalendarFiles/20170717080647-Popik,%20Resilient%20Societies.pdf.

[324] California Public Utility Commission (CPUC), California Independent System Operator (CAISO), Los Angeles Department of Water and Power (LADWP), and Southern Company, *Aliso Canyon Risk Assessment Technical Report* (CPUC, CAISO, LADPW, and Southern Co., April 2016), http://www.energy.ca.gov/2016_energypolicy/documents/2016-04-08_joint_agency_workshop/Aliso_Canyon_Risk_Assessment_Technical_Report.pdf.

[325] PJM Interconnection, *Appendix to PJM's Evolving Resource Mix and System Stability* (PJM Interconnection, March 2017), http://www.pjm.com/~/media/library/reports-notices/special-reports/20170330-appendix-to-pjms-evolving-resource-mix-and-system-reliability.ashx.

[326] North American Electric Reliability Corporation (NERC), *Polar Vortex Review* (Atlanta, GA: September 2014), 19, http://www.nerc.com/pa/rrm/January%202014%20Polar%20Vortex%20Review/Polar_Vortex_Review_29_Sept_2014_Final.pdf.

[327] Alyson Kenward, "In Tennessee, Heat Waves Diminish Nuclear Power Output," April 11, 2011, http://www.climatecentral.org/news/in-tennessee-heat-waves-frustrate-nuclear-power

[328] World Nuclear Association, "The Nuclear Fuel Cycle". Last modified March 2017. http://www.world-nuclear.org/information-library/nuclear-fuel-cycle/introduction/nuclear-fuel-cycle-overview.aspx

[329] North American Electric Reliability Corporation (NERC), *Polar Vortex Review* (Atlanta, GA: NERC, September 2014), http://www.nerc.com/pa/rrm/January%202014%20Polar%20Vortex%20Review/Polar_Vortex_Review_29_Sept_2014_Final.pdf.

[330] World Nuclear Association, "The Nuclear Fuel Cycle". Last modified March 2017. http://www.world-nuclear.org/information-library/nuclear-fuel-cycle/introduction/nuclear-fuel-cycle-overview.aspx

[331] "Electricity Monthly Update May 2017: Electric Power Sector Coal Stocks," Energy Information Administration, July 31, 2017, https://www.eia.gov/electricity/monthly/update/fossil_fuel_stocks.php

[332] "Electricity Monthly Update May 2017: Electric Power Sector Coal Stocks," Energy Information Administration, July 31, 2017, https://www.eia.gov/electricity/monthly/update/fossil_fuel_stocks.php.

[333] Federal Energy Regulatory Commission (FERC), "Coal Delivery Issues for Electric Generation: Staff Overview" (Washington, DC: FERC, December 18, 2014), Item No. A-3, https://www.ferc.gov/media/headlines/2014/2014-4/A-3-presentation-staff.pdf.

[334] Benjamin L. Preston, Scott N. Backhaus, Mary Ewers, Julia A. Phillips, Cesar A. Silva-Monroy, Jeffery E. Dagle, Alfonso G. Tarditi, John (Pat) Looney, and Thomas J. King, Jr., *Resilience of the U.S. Electricity System: A Multi-Hazard Perspective* (Department of Energy, August 2016), https://energy.gov/sites/prod/files/2017/01/f34/Resilience%20of%20the%20U.S.%20Electricity%20System%20A%20Multi-Hazard%20Perspective.pdf.

[335] Department of Energy (DOE), Transforming the Nation's Electricity System: The Second Installment of the Quadrennial Energy Review (Washington, DC: DOE, January 2017), Chapter 4, Page 23-24. Accessed August 2017. https://energy.gov/sites/prod/files/2017/01/f34/Chapter%20IV%20Ensuring%20Electricity%20System%20Reliability%2C%20Security%2C%20and%20Resilience.pdf

[336] NERC, Risk Profile #1, Changing Resource Mix. Accessed August 2017. http://www.nerc.com/comm/RISC/Documents/All%20profiles.pdf

[337] North American Electric Reliability Corporation (NERC), *Polar Vortex Review* (Atlanta, GA: NERC, September 2014), http://www.nerc.com/pa/rrm/January%202014%20Polar%20Vortex%20Review/Polar_Vortex_Review_29_Sept_2014_Final.pdf.

[338] PJM Interconnection, *Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events* (PJM Interconnection, May 8, 2014), http://www.pjm.com/~/media/library/reports-notices/weather-related/20140509-analysis-of-operational-events-and-market-impacts-during-the-jan-2014-cold-weather-events.ashx.

[339] North American Electric Reliability Corporation (NERC), *Polar Vortex Review* (Atlanta, GA: NERC, September 2014), http://www.nerc.com/pa/rrm/January%202014%20Polar%20Vortex%20Review/Polar_Vortex_Review_29_Sept_2014_Final.pdf

[340] Federal Energy Regulatory Commission (FERC), *Winter 2013–2014 Operations and Market Performance in RTOs and ISOs* (Washington, DC: FERC, April 1, 2014), AD14-8-000, https://www.ferc.gov/legal/staff-reports/2014/04-01-14.pdf.

[341] The National Coal Council, "Coal = Reliable Energy" (Washington, DC : The National Coal Council, 2015), http://www.nationalcoalcouncil.org/Documents/Energy-Education/4-Coal-Reliable-Energy-Final.pdf.

[342] PJM Interconnection, *Analysis of Operational Events and Market Impacts during the January 2014 Cold Weather Events* (PJM Interconnection, May 8, 2014), http://www.pjm.com/~/media/library/reports-notices/weather-related/20140509-analysis-of-operational-events-and-market-impacts-during-the-jan-2014-cold-weather-events.ashx.

[343] The National Coal Council, *Reliable & Resilient, The Value of Our Existing Coal Fleet: An Assessment of Measures to Improve Reliability and Efficiency While Reducing Emissions* (Washington, DC: National Coal Council, May 2014), http://www.nationalcoalcouncil.org/reports/1407/NCCValueExistingCoalFleet.pdf.

[344] The National Coal Council, *Reliable & Resilient, The Value of Our Existing Coal Fleet: An Assessment of Measures to Improve Reliability & Efficiency While Reducing Emissions* (Washington, DC: The National Coal Council, May 2014), 2, http://www.nationalcoalcouncil.org/reports/1407/NCCValueExistingCoalFleet.pdf.

[345] North American Electric Reliability Corporation (NERC), *Polar Vortex Review* (Atlanta, GA: NERC, September 2014), http://www.nerc.com/pa/rrm/January%202014%20Polar%20Vortex%20Review/Polar_Vortex_Review_29_Sept_2014_Final.pdf.

[346] U.S. Department of Energy (DOE), "Comparing the Impacts of Northeast Hurricanes on Energy Infrastructure." Table 5, p 13. Office of Electricity Delivery and Energy Reliability. April 2013. https://energy.gov/sites/prod/files/2013/04/f0/Northeast%20Storm%20Comparison_FINAL_041513b.pdf.

[347] U.S. Department of Energy (DOE), Office of Electricity Delivery and Energy (OE), *Northeast Hurricanes on Energy Infrastructure* (Washington, DC: DOE-OE, April 2013), https://energy.gov/sites/prod/files/2013/04/f0/Northeast%20Storm%20Comparison_FINAL_041513b.pdf.

[348] Tom Johnson, "PSE&G Solar Systems Took Big Hit from Hurricane Sandy," *NJ Spotlight*, July 10, 2013, http://www.njspotlight.com/stories/13/07/09/pse-g-solar-systems-take-big-hit-from-hurricane-sandy/.

[349] PJM Interconnection, *PJM's Evolving Resource Mix and System Reliability* (PJM Interconnection, March 2017), http://www.pjm.com/~/media/library/reports-notices/special-reports/20170330-pjms-evolving-resource-mix-and-system-reliability.ashx.

[350] PJM Interconnection, *PJM's Evolving Resource Mix and System Reliability* (PJM Interconnection, March 2017), http://www.pjm.com/~/media/library/reports-notices/special-reports/20170330-pjms-evolving-resource-mix-and-system-reliability.ashx.

[351] Johannes Pfeifenberger, Judy Chang, and Akarsh Sheilendranath, *Toward More Effective Transmission Planning: Addressing the Costs and Risks of an Insufficiently Flexible Electricity Grid* (The Brattle Group, April 2015), 36–37, http://wiresgroup.com/docs/reports/WIRES%20Brattle%20Rpt_TransPlanning_042315.pdf.

[352] Eric Vugrin, Anya Castillo, Cesar Silva-Monroy, *Resilience Metrics for the Electric Power System: A Performance-Based Approach* (Albuquerque, NM: Sandia National Laboratories, 2017), http://prod.sandia.gov/techlib/access-control.cgi/2017/171493.pdf.

[353] Joseph Bowring (president, Monitoring Analytics), telephone conversation with Department of Energy staff concerning his report and relevant matters based on his role as PJM market monitor, June 28, 2017.

[354] Michael Hogan, "Follow the Missing Money: Ensuring Reliability at Least Cost to Consumers in the Transition to a Low-Carbon Power System," *The Electricity Journal* 30, no. 1 (January–February 2017): 55–61, doi: 10.1016/j.tej.2016.12.006.

[355] E. Ela, M. Milligan, A. Bloom, A. Botterud, A. Townsend, and T. Levin, *Evolution of Wholesale Electricity Market Design with Increasing Levels of Renewable Generation* (Golden, CO: National Renewable Energy Laboratory, September 2014), http://www.nrel.gov/docs/fy14osti/61765.pdf.

[356] Department of Energy (DOE), *Transforming the Nation's Electricity System: The Second Installment of the Quadrennial Energy Review* (Washington, DC: DOE, January 2017), A-11, https://www.energy.gov/sites/prod/files/2017/02/f34/Quadrennial%20Energy%20Review--Second%20Installment%20%28Full%20Report%29.pdf.

[357] Karl McDermott, *Cost of Service Regulation In the Investor-Owned Electric Utility Industry: A History of Adaptation* (Washington, DC: Edison Electric Institute, June 2012), 22–24, http://www.eei.org/issuesandpolicy/stateregulation/Documents/COSR_history_final.pdf.

[358] Karl McDermott, *Cost of Service Regulation In the Investor-Owned Electric Utility Industry: A History of Adaptation* (Washington, DC: Edison Electric Institute, June 2012), 30, http://www.eei.org/issuesandpolicy/stateregulation/Documents/COSR_history_final.pdf.

[359] Public Utilities Regulatory Policy Act of 1978, 16 U.S.C. § 260 (1978), http://legcounsel.house.gov/Comps/PURPA78.PDF.

[360] Public Utilities Regulatory Policy Act of 1978, 16 U.S.C. § 260 (1978), http://legcounsel.house.gov/Comps/PURPA78.PDF.

[361] Energy Policy Act of 1992, 42 U.S.C. § 13201 (1992).

[362] "Renewable Energy Production Tax Credit Webpage," Department of Energy, accessed August 3, 2017, https://energy.gov/savings/renewable-electricity-production-tax-credit-ptc.

[363] Federal Energy Regulatory Commission (FERC), Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Docket Nos. RM95-8-000 and RM94-7-001, Order No. 888," Federal Energy Regulatory Commission, (Washington, DC: FERC, April 24, 1996), https://www.ferc.gov/legal/maj-ord-reg/land-docs/order888.asp.

[364] Federal Energy Regulatory Commission (FERC), *Regional Transmission Organizations, Docket No. RM99-2-000; Order No. 2000* (Washington, DC: FERC, December 1999), https://www.ferc.gov/legal/maj-ord-reg/land-docs/RM99-2A.pdf.

[365] Christine Marshall, Robert Blair, Jonathan Abe, and Christopher Clark, "FERC Order 2000 Drives RTO Initiatives; ISOs, Transcos Prevail," *Electric Light & Power*, May 1, 2001, http://www.elp.com/articles/print/volume-79/issue-5/industry-news/ferc-order-2000-drives-rto-initiatives-isos-transcos-prevail.html.

[366] Christine Marshall, Robert Blair, Jonathan Abe, and Christopher Clark, "FERC Order 2000 Drives RTO Initiatives; ISOs, Transcos Prevail," *Electric Light & Power*, May 1, 2001, http://www.elp.com/articles/print/volume-79/issue-5/industry-news/ferc-order-2000-drives-rto-initiatives-isos-transcos-prevail.html.

[367] S&P Global Market Intelligence, created by DOE staff from mapping utility website. https://www.snl.com/web/client?auth=inherit#mapping/map?mapId=1e2ae3a6-59ae-4f6c-9f4c-1023dafd3b83&share=1&bbox=-138.252%2C54.9271%2C-57.3047%2C11.2646%2C4326

[368] Department of Energy (DOE), *Transforming the Nation's Electricity System: The Second Installment of the Quadrennial Energy Review* (Washington, DC: DOE, January 2017), Fig. A-8, https://www.energy.gov/sites/prod/files/2017/02/f34/Quadrennial%20Energy%20Review--Second%20Installment%20%28Full%20Report%29.pdf

[369] Department of Energy (DOE), *Transforming the Nation's Electricity System: The Second Installment of the Quadrennial Energy Review* (Washington, DC: DOE, January 2017), Fig. A-9, https://www.energy.gov/sites/prod/files/2017/02/f34/Quadrennial%20Energy%20Review--Second%20Installment%20%28Full%20Report%29.pdf.

[370] Federal Energy Regulatory Commission (FERC)*, Energy Primer: A Handbook of Energy Market Basics* (Washington, DC: FERC, November 2015), https://ferc.gov/market-oversight/guide/energy-primer.pdf.

[371] Midcontinent Independent System Operator, "2016 Value Proposition: Stakeholder Review Meeting" (presented on February 2017), Slide 5, https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/Workshops%20and%20Special%20Meetings/2017/Value%20Proposition/2016%20Value%20Proposition%20Presentation.pdf.

[372] Tony Clark, *Regulation and Markets: Ideas for Solving the Identity Crisis* (Washington, DC: Wilkinson Barker Knauer, July 2017), http://www.wbklaw.com/uploads/file/Articles-%20News/2017%20articles%20publications/Market%20Identity%20Crisis%20Final%20(7-14-17).pdf.

[373] Federal Energy Regulatory Commission (FERC), *Staff Analysis of Shortage Pricing in RTO and ISO Markets* (Washington, DC: FERC, October 2014), Docket No. AD14-14-000, https://www.ferc.gov/legal/staff-reports/2014/AD14-14-pricing-rto-iso-markets.pdf.

[374] Federal Energy Regulatory Commission (FERC), "Procedures for utilities requesting termination of obligation to purchase from qualifying facilities, " 18 C.F.R. § 312 – 313, https://www.ecfr.gov/cgi-bin/text-idx?c=ecfr&sid=5f16b3cdb9bef3509dc795c32a3fa674&rgn=div6&view=text&node=18:1.0.1.11.58.3&idno=18#se18.1.292_1310.

[375] Federal Energy Regulatory Commission, "Implementation Issues under the Public Utility Regulatory Policies Act of 1978 (Docket No. AD16-16-000)" (FERC Technical Conference, June 29, 2016), https://www.ferc.gov/EventCalendar/EventDetails.aspx?ID=8242&CalType=&CalendarID=116&Date=06/29/2016&View=Listview.

[376] D. B. Patton (Independent Market Monitor for The New York Independent System Operator), written statement submitted to the Federal Energy Regulatory Commission, "Joint Technical Conference on New York Markets & Infrastructure (Docket AD14-18-000)," https://www.ferc.gov/CalendarFiles/20141119133149-D%20Patton%20Written%20Statement_11-5-14.pdf.

[377] William Hogan, Harvard University, *On An "Energy Only" Electricity Market Design For Resource Adequacy*, September 23, 2005, https://sites.hks.harvard.edu/fs/whogan/Hogan_Energy_Only_092305.pdf

[378] Federal Energy Regulatory Commission (FERC), *Staff Analysis of Shortage Pricing in RTO and ISO Markets* (Washington, DC: FERC, October 2014), Docket No. AD14-14-000, https://www.ferc.gov/legal/staff-reports/2014/AD14-14-pricing-rto-iso-markets.pdf.

[379] Federal Energy Regulatory Commission (FERC), *Offer Caps in Markets Operated by Regional Transmission Organizations and Independent System Operators, Docket No. RM16-5-000; Order No. 831* (Washington, DC: FERC, November 17, 2016), https://www.ferc.gov/whats-new/comm-meet/2016/111716/E-2.pdf.

[380] Rich Heidorn, Jr., "Lawyers Take an Economics Class: Capacity Markets vs. Scarcity Pricing," *RTO Insider*, June 13, 2016, https://www.rtoinsider.com/capacity-markets-vs-scarcity-pricing-27702/.

[381] Rich Heidorn, Jr., "Lawyers Take an Economics Class: Capacity Markets vs. Scarcity Pricing," *RTO Insider*, June 13, 2016, https://www.rtoinsider.com/capacity-markets-vs-scarcity-pricing-27702/.

[382] K. Spees, S. Newell, and J. Pfeifenberger, "Capacity Markets—Lessons Learned from the First Decade," *Economics of Energy & Environmental Policy* 2, no. 2 (2013): 26, doi: 10.5547/2160-5890.2.2.1.

[383] K. Spees, S. Newell, and J. Pfeifenberger, "Capacity Markets—Lessons Learned from the First Decade," *Economics of Energy & Environmental Policy* 2, no. 2 (2013): 26, doi: 10.5547/2160-5890.2.2.1.

[384] Hung-po Chao, "Economics Behind Capacity Construct," PJM Interconnection, March 2017, slide 6, http://www.pjm.com/-/media/committees-groups/task-forces/ccppstf/20170306/20170306-item-06-economics-behind-capacity-construct.ashx.

[385] Monitoring Analytics, LLC, *2016 State of the Market Report for PJM* (Monitoring Analytics, LLC, March 2017), 279–80, http://www.monitoringanalytics.com/reports/pjm_state_of_the_market/2016.shtml.

[386] Severin Borenstein, "Electricity Markets and Missing Money," *The Energy Collective* (blog), April 4, 2017, http://www.theenergycollective.com/severinborenstein/2401671/electricity-markets-missing-money.

[387] Department of Energy (DOE), *Transforming the Nation's Electricity System: The Second Installment of the Quadrennial Energy Review* (Washington, DC: DOE, January 2017), 4-9, https://www.energy.gov/sites/prod/files/2017/02/f34/Quadrennial%20Energy%20Review--Second%20Installment%20%28Full%20Report%29.pdf.

[388] Monitoring Analytics, LLC, *2017 Quarterly State of the Market for PJM: January through March 2017* (Monitoring Analytics, May 2017), 98, http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2017/2017q1-som-pjm.pdf.

[389] Tyler Hodge, "Average Utilization for Natural Gas Combined-Cycle Plants Exceeded Coal Plants in 2015," *Today in Energy,* Energy Information Administration, April 4, 2016, https://www.eia.gov/todayinenergy/detail.php?id=25652.

[390] Ryan Wiser, Andrew Mills, et al., *Impacts of Variable Renewable Energy on Bulk Power System Assets, Pricing and Costs*, June 2017 draft (Lawrence Berkeley National Laboratory, forthcoming).

[391] PJM Interconnection, "PJM Provides the Following Documents and Information for the Department's Consideration as It Prepares Its Report in Response to the Secretary's Memorandum of April 14, 2017," sent by PJM Interconnection to the Department of Energy, May 3, 2017.

[392] "Negative Prices in Wholesale Markets Indicate Supply Inflexibilities," *Today in Energy*, Energy Information Administration, February 23, 2012, https://www.eia.gov/todayinenergy/detail.php?id=5110.

[393]PJM Interconnection, "PJM Provides the Following Documents and Information for the Department's Consideration as It Prepares Its Report in Response to the Secretary's Memorandum of April 14, 2017," sent by PJM Interconnection to the Department of Energy, May 3, 2017.

[394] Potomac Economics, *2016 State of the Market Report for the ERCOT Electricity Markets* (Fairfax, VA: Potomac Economics, May 2017), i, https://www.potomaceconomics.com/wp-content/uploads/2017/06/2016-ERCOT-State-of-the-Market-Report.pdf.

[395] William W. Hogan and Susan L. Pope, *Priorities for the Evolution of an Energy-Only Electricity Market Design in ERCOT* (FTI Consulting, 2017), https://sites.hks.harvard.edu/fs/whogan/Hogan_Pope_ERCOT_050917.pdf.

[396] Ryan Wiser, Andrew Mills, et al., *Impacts of Variable Renewable Energy on Bulk Power System Assets, Pricing and Costs*, June 2017 draft (Berkeley, CA: Lawrence Berkeley National Laboratory, forthcoming).

[397] Robert Mullin, "Spring Oversupply Lifts CAISO Curtailments," *RTO Insider,* April 24, 2017, https://www.rtoinsider.com/caiso-duck-curve-curtailments-42004/.

[398] "Negative Prices in Wholesale Markets Indicate Supply Inflexibilities," *Today in Energy*, Energy Information Administration, February 23, 2012, https://www.eia.gov/todayinenergy/detail.php?id=5110.

[399] Roy Shanker (independent consultant), "State Policies and Wholesale Markets Operated by ISO New England Inc., New York Independent System Operator, Inc., and PJM Interconnection, L.L.C. (Docket No. AD17-11-000)" (written statement submitted to the Federal Energy Regulatory Commission, Technical Conference, May 1–2, 2017), https://www.ferc.gov/CalendarFiles/20170426151725-Shanker,%20Consultant.pdf.

[400] William Hogan (Harvard University), "State Policies and Wholesale Markets Operated by ISO New England Inc., New York Independent System Operator, Inc., and PJM Interconnection, L.L.C. (Docket No. AD17-11-000)" (written statement submitted to the Federal Energy Regulatory Commission, Technical Conference, May 1–2, 2017), https://www.ferc.gov/CalendarFiles/20170426151558-Hogan,%20Harvard.pdf.

[401] Susan Tierney, Analysis Group, "State Policies and Wholesale Markets Operated by ISO New England Inc., New York Independent System Operator, Inc., and PJM Interconnection, L.L.C. (Docket No. AD17-11-000)" (written statement submitted to the Federal Energy Regulatory Commission, Technical Conference, May 1–2, 2017), https://www.ferc.gov/CalendarFiles/20170426151811-Tierney,%20Analysis%20Group.pdf.

[402] Cliff Hamel (Navigant Economics), "State Policies and Wholesale Markets Operated by ISO New England Inc., New York Independent System Operator, Inc., and PJM Interconnection, L.L.C. (Docket No. AD17-11-000)" (written statement submitted to the Federal Energy Regulatory Commission Technical Conference, May 1–2, 2017, https://www.ferc.gov/CalendarFiles/20170426151541-Hamal,%20Navigant.pdf.

[403] Samuel Newell (The Brattle Group), "State Policies and Wholesale Markets Operated by ISO New England Inc., New York Independent System Operator, Inc., and PJM Interconnection, L.L.C. (Docket No. AD17-11-000)" (written statement

submitted to the Federal Energy Regulatory Commission, Technical Conference, May 1–2, 2017), https://www.ferc.gov/CalendarFiles/20170426151703-Newell,%20The%20Brattle%20Group.pdf.

[404] Lawrence Makovich (IHS Markit), "State Policies and Wholesale Markets Operated by ISO New England Inc., New York Independent System Operator, Inc., and PJM Interconnection, L.L.C. (Docket No. AD17-11-000)" (written statement submitted to the Federal Energy Regulatory Commission, Technical Conference, May 1–2, 2017), https://www.ferc.gov/CalendarFiles/20170426151642-Makovich,%20IHS%20Markit.pdf.

[405] Jeffrey Bentz, (New England States Committee on Electricity), transcript for FERC "State Policies and Wholesale Markets Operated by ISO New England Inc., New York Independent System Operator, Inc., and PJM Interconnection, L.L.C. (Docket No. AD17-11-000)," Technical Conference, May 1, 2017, 40, https://www.ferc.gov/CalendarFiles/20170530122035-Transcript,%20May%201,%202017.pdf

[406] Angela O'Connor, (Chairman, Department of Public Utilities of Massachusetts), transcript for FERC "State Policies and Wholesale Markets Operated by ISO New England Inc., New York Independent System Operator, Inc., and PJM Interconnection, L.L.C. (Docket No. AD17-11-000)," Technical Conference, May 1, 2017, https://www.ferc.gov/CalendarFiles/20170530122035-Transcript,%20May%201,%202017.pdf.

[407] Sarah Hofmann, (Board Member, Vermont Public Service Board, speaking on behalf of the National Council on Electricity Policy), written statement submitted for FERC "State Policies and Wholesale Markets Operated by ISO New England Inc., New York Independent System Operator, Inc., and PJM Interconnection, L.L.C. (Docket No. AD17-11-000)," Technical Conference, May 1-2, 2017), https://www.ferc.gov/CalendarFiles/20170426145922-Hofmann,%20Vermont%20Public%20Service%20Board.pdf.

[408] Tony Clark, *Regulation and Markets: Ideas for Solving the Identity Crisis* (Washington, DC: Wilkinson Barker Knauer, July 2017), http://www.wbklaw.com/uploads/file/Articles-%20News/2017%20articles%20publications/Market%20Identity%20Crisis%20Final%20(7-14-17).pdf.

[409] Federal Energy Regulatory Commission (FERC), "Order on [ISO-NE] Tariff Filing and Instituting Section 206 Proceeding (Dockets Nos. ER14-1050-000, ER14-1050-001, and EL14-52-000)," May 30, 2014, https://www.iso-ne.com/regulatory/ferc/orders/2014/may/er14-1050-000_5-30-14_pay_for_performance_order.pdf

[410] Federal Energy Regulatory Commission (FERC), "Order on Proposed [PJM] Tariff Revisions (Dockets Nos. ER15-623, ER15-623-000, EL15-29-000, ER15-623-001, EL15-41-000)," June 9, 2015, https://elibrary.ferc.gov/idmws/File_list.asp?document_id=14346363

[411] Department of Energy (DOE), *Grid Modernization Multi-Year Program Plan* (Washington, DC: DOE, November 2015), 5, https://energy.gov/sites/prod/files/2016/01/f28/Grid%20Modernization%20Multi-Year%20Program%20Plan.pdf.

[412] Department of Health and Human Services (HHS), *LIHEAP Home Energy Notebook for Fiscal Year 2011* (Washington, DC: HHS, June 2014), 88, https://www.acf.hhs.gov/sites/default/files/ocs/fy2011_hen_final.pdf.

[413] Ariel Drehobl and Lauren Ross, *Lifting the High Energy Burden in America's Largest Cities: How Energy Efficiency Can Improve Low Income and Underserved Communities* (Washington, DC: American Council for an Energy-Efficient Economy, April 2016), 8, http://energyefficiencyforall.org/sites/default/files/Lifting%20the%20High%20Energy%20Burden_0.pdf.

[414] Department of Health and Human Services (HHS), "Table 2-1a. Residential Energy: Average Annual Household Consumption, Expenditures, and Burden by All Households, by Main Heating Fuel Type, United States, FY 2011," in *LIHEAP Home Energy Notebook for Fiscal Year 2011* (Washington, DC: HHS, June 2014), 4, https://www.acf.hhs.gov/sites/default/files/ocs/fy2011_hen_final.pdf.

[415] Department of Health and Human Services (HHS), "Table 2-1c. Residential Energy: Average Annual Household Consumption, Expenditures, and Burden by Low Income Households, by Main Heating Fuel Type, United States, FY 2011," in *LIHEAP Home Energy Notebook for Fiscal Year 2011* (Washington, DC: HHS, June 2014), 4, https://www.acf.hhs.gov/sites/default/files/ocs/fy2011_hen_final.pdf.

[416] Ariel Drehobl and Lauren Ross, "Lifting the High Energy Burden in America's Largest Cities: How Energy Efficiency Can Improve Low-Income and Underserved Communities," April 2016, http://aceee.org/research-report/u1602.

[417] Jayanta Bhattacharya, Thomas DeLeire, Steven Haider, and Janet Currie, "Heat or Eat? Cold-Weather Shocks and Nutrition in Poor American Families," *American Journal of Public Health* 93, no. 7 (2003): 1153, doi:10.2105/AJPH.93.7.1149.

[418] "Special Medical Needs," Hawaiian Electric Company, accessed August 1, 2017, https://www.hawaiianelectric.com/my-account/energy-assist-programs/special-medical-needs.

[419] Google, "Data center locations," Accessed August 2017, https://www.google.com/about/datacenters/inside/locations/index.html.

[420] Penny Jones, "Energy Prices Likely to Predict Key Data Center Market Moves, Analyst Says," Datacenter Dynamics, March 2013, http://www.datacenterdynamics.com/news/energy-prices-likely-to-predict-key-data-center-market-moves-analyst-says/74618.fullarticle

[421] U.S. Energy Information Administration, "Rankings: Average Retail Price of Electricity to Residential Sector, May 2017," Accessed August 2017, https://www.eia.gov/state/rankings/#/series/31

[422] Natural Resources Defense Council, "Data Center Efficiency Assessment: Scaling Up Energy Efficiency Across the Data Center Industry; Evaluating Key Drivers and Barriers," August 2014, https://www.nrdc.org/sites/default/files/data-center-efficiency-assessment-IP.pdf.

[423] "Corporate Renewable Deals, 2012–2017," Rocky Mountain Institute Business Renewables Center, June 2017, http://businessrenewables.org/corporate-transactions/.

[424] "Factors Affecting Electricity Prices," Energy Information Administration, May 2017, https://www.eia.gov/energyexplained/index.cfm/index.cfm?page=electricity_factors_affecting_prices.

[425] M. Tyson Brown and Marc Harnish, "Many Industrial Electricity Customers Are Farmers," *Today in Energy*, Energy Information Administration, May 2014, https://www.eia.gov/todayinenergy/detail.php?id=16231.

[426] Joshua D. Rhodes, Carey W. King, Gurcan Gulen, Sheila M. Olmstead, James S. Dyer, Robert E. Hebner, Fred C. Beach, Thomas F. Edgar, and Michael E. Webber, "The Full Cost of Electricity: New U.S. Power Costs: by County, with Environmental Externalities," July 2016, Page 11, https://energy.utexas.edu/files/2016/09/UTAustin_FCe_LCOE_2016-A.pdf.

[427] U.S. Energy Information Administration, "Electricity Explained: Factors Affecting Electricity Prices." https://www.eia.gov/energyexplained/index.cfm?page=electricity_factors_affecting_prices

[428] Bonbright, James C., "Principles of Public Utility Ratemaking: Chapter VI Competitive Price as a Norm of Rate Regulation," (New York: Columbia University Press, 1961), Reprinted with Permission by Powell Goldstein LLP 2005, http://media.terry.uga.edu/documents/exec_ed/bonbright/principles_of_public_utility_rates.pdf.

[429] U.S. Energy Information Administration, "Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2017," April 2017, https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf

[430] Dave Lamont and John Gerhard, "The Treatment of Energy Efficiency in Integrated Resource Plans," Regulatory Assistance Project, January 2013, http://www.raponline.org/wp-content/uploads/2016/05/rap-lamont-gerhard-treatementofeeinirp-2013-jan-28.pdf.

[431] Harvey Averch and Leland L. Johnson, "Behavior of the Firm Under Regulatory Constraint," The American Economic Review, Vol. 52, No. 5, December 1962, https://www.jstor.org/stable/pdf/1812181.pdf.

[432] Oliver Grawe, "Intra-firm Subsidization and Regulation: Do Profits Cover Losses, or Do Losses Justify Profits, and Does It Matter?," Federal Trade Commission Bureau of Economics, June 1983, https://www.ftc.gov/system/files/documents/reports/intra-firm-subsidization-regulation-do-profits-cover-losses-or-do-losses-justify-profits-does-it/wp091.pdf.

[433] New England Independent System Operator, "Wholesale vs. Retail Electricity Costs," Accessed August 2017, https://www.iso-ne.com/about/what-we-do/in-depth/wholesale-vs-retail-electricity-costs.

[434] New York Independent System Operator, "Impact of Wholesale Prices on Consumer Bills," Accessed August 2017, https://home.nyiso.com/how-wholesale-prices-factor-in-end-use-consumer-bills/.

[435] Regulatory Assistance Project, "Electricity Regulation in the US: A Guide," June 2016, Pages 68-76, 102-105, http://www.raponline.org/wp-content/uploads/2016/07/rap-lazar-electricity-regulation-US-june-2016.pdf.

[436] G. Barbose, L. Bird, J. Heeter, F. Flores, and R. Wiser, *Costs and Benefits of Renewables Portfolio Standards in the United* States (Berkeley, CA: Lawrence Berkeley National Laboratory, July 2015), LBNL-187516, https://emp.lbl.gov/sites/default/files/lbnl-187516.pdf.

[437] WM Warwick, TD Hardy, MG Hoffman, and JS Homer, "Electricity Distribution System Baseline Report Chapter 3.0 Toward a 21st Century Utility," July 2016, https://www.energy.gov/sites/prod/files/2017/01/f34/Electricity%20Distribution%20System%20Baseline%20Report.pdf

[438] Ryan H. Wiser, Galen L. Barbose, and Mark Bolinger, *Retail Rate Impacts of Renewable Electricity: Some First Thoughts* (Berkeley, CA: Lawrence Berkeley National Laboratory, March 2017), https://emp.lbl.gov/publications/retail-rate-impacts-renewable.

[439] Energy Information Administration, "Annual Average Residential Electricity Price," in *Short-Term Energy Outlook* (Washington, DC: EIA, July 2017), https://www.eia.gov/outlooks/steo/realprices/.

[440] Energy Information Administration (EIA), "Short-Term Energy Outlook, Annual Average Residential Electricity Price," in *Short-Term Energy Outlook* (Washington, DC: EIA, July 2017), https://www.eia.gov/outlooks/steo/realprices/.

[441] "2015 Total Electric Industry, Average Retail Price (cents/kWh)," Energy Information Administration, accessed August 4, 2017, https://www.eia.gov/electricity/sales_revenue_price/pdf/table4.pdf.

[442] "Table 6: 2015 Utility Bundled Retail Sales – Residential," Energy Information Administration, https://www.eia.gov/electricity/data.php#sales.

[443] "Rankings: Average Retail Price of Electricity to Residential Sector, March 2017 (cents/kWh)," Energy Information Administration, accessed August 4 2017, https://www.eia.gov/state/rankings/?sid=US#/series/31.

[444] Energy Information Administration (EIA), *Capital Cost Estimates for Utility Scale Electricity Generating Plants* (Washington, DC: EIA, November 2016), 7, https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capcost_assumption.pdf.

[445] "Form EIA-860m: Preliminary Monthly Electric Generator Inventory" Energy Information Administration, March 2017, https://www.eia.gov/electricity/data/eia860m/.

[446] S&P Global Intelligence, obtained by DOE using their database of electricity spot prices and Intercontinental Exchange natural gas spot prices taken from ABB's Energy Velocity Suite.

[447] Federal Energy Regulatory Commission (FERC), *2016 State of the Markets Report* (Washington, DC: FERC, April 2017), 13, https://www.ferc.gov/market-oversight/reports-analyses/st-mkt-ovr/2016-som.pdf.

[448] Federal Energy Regulatory Commission (FERC), *2016 State of the Markets Report* (Washington, DC: FERC, April 2017), 13, https://www.ferc.gov/market-oversight/reports-analyses/st-mkt-ovr/2016-som.pdf.

[449] J. Bushnell, E. Mansur, and K. Novan, *Review of the Economics Literature on U.S. Electric Restructuring*, April 2016 draft (Department of Energy, forthcoming).

[450] Energy Information Administration (EIA), *Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2017* (Washington, DC: EIA, April, 2017), 8, https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf.

[451] G. Barbose, L. Bird, J. Heeter, F. Flores, and R. Wiser, *Costs and Benefits of Renewables Portfolio Standards in the United* States (Berkeley, CA: Lawrence Berkeley National Laboratory, July 2015), LBNL-187516, https://emp.lbl.gov/sites/default/files/lbnl-187516.pdf.

[452] Juan Andrade and Ross Baldick, "The Full Cost of Electricity: Estimation of Transmission Costs for New Generation," September 2016, https://energy.utexas.edu/files/2016/11/UTAustin_FCe_TransmissionCosts_2016.pdf.

[453] Jaquelin Cochran, "Session 3: Impact on U.S. Ancillary Services Markets from Variable Renewable Energy," April 2013, https://www.nrel.gov/docs/fy13osti/58553.pdf

[454] Edison Electric Institute, "Transmission Projects: At A Glance," Page v, December, 2016, http://www.eei.org/issuesandpolicy/transmission/Documents/Trans_Project_lowres_bookmarked.pdf.

[455] SNL Financial, "Length of Transmission Lines (miles)," Analysis of FERC Form 1: Electric Utility Annual Report data, subscription service www.snl.com

[456] U.S. Department of Energy, "Renewable Electricity Production Tax Credit (PTC)," Accessed August 2017, https://energy.gov/savings/renewable-electricity-production-tax-credit-ptc.

[457] U.S. Department of Energy, "Business Energy Investment Tax Credit (ITC)," Accessed August 2017, https://energy.gov/savings/business-energy-investment-tax-credit-itc.

[458] Trieu Mai, Wesley Cole, Eric Lantz, Cara Marcy, and Benjamin Sigrin, "Impacts of Federal Tax Credit Extensions on Renewable Deployment and Power Sector Emissions," February 2016, https://www.nrel.gov/docs/fy16osti/65571.pdf

[459] Chris Nelder, "Congress Just Extended the PTC and ITC: What You Need to Know," Rocky Mountain Institute, January 2015, https://www.rmi.org/news/congress-just-extended-ptc-itc-need-know/

[460] Midcontinent Independent System Operator, "MISO Transmission Cost Allocation Overview," October 2013, https://www.misoenergy.org/Library/Repository/Communication%20Material/Key%20Presentations%20and%20Whitepapers/Transmission%20Cost%20Allocation%20Overview.pdf

[461] William W. Hogan, "Transmission Benefits and Cost Allocation," May 2011, https://sites.hks.harvard.edu/fs/whogan/Hogan_Trans_Cost_053111.pdf.

[462] Energy Reliability Council of Texas, "Analysis of Transmission Alternatives for Competitive Renewable Energy Zones in Texas," December 2006, http://www.ercot.com/content/news/presentations/2006/ATTCH_A_CREZ_Analysis_Report.pdf

[463] Jeffrey S. Dennis, Federal Energy Regulatory Commission (FERC), "Transmission Cost Allocation and 'Beneficiary Pays,'" January 2015, International Energy Agency ESAP and CEER Expert Workshop IV, https://www.iea.org/media/workshops/2015/esapworkshopiv/Dennis.pdf.

[464] Jess Jiang, "The Price of Electricity In Your State," *National Public Radio,* October 28, 2011. Accessed August, 2017. http://www.npr.org/sections/money/2011/10/27/141766341/the-price-of-electricity-in-your-state

[465] Robert Fares, "The U.S. Electric Grid's Cost in 2 Charts," Scientific American, April 5, 2017. Accessed August, 2017. https://blogs.scientificamerican.com/plugged-in/the-u-s-electric-grids-cost-in-2-charts/

[466] Galen Barbose, *Putting the Potential Rate Impacts of Distributed Solar into Context* (Berkeley, CA: Lawrence Berkeley National Laboratory, Energy Analysis and Impacts Division, January 2017), LBNL-1007060, https://emp.lbl.gov/sites/default/files/lbnl-1007060.pdf.

[467] PJM Interconnection, *Energy Price Formation and Valuing Flexibility* (PJM Interconnection, June 2017), http://www.pjm.com/~/media/library/reports-notices/special-reports/20170615-energy-market-price-formation.ashx.

[468] Midcontinent Independent System Operator Energy, "Extended Locational Marginal Pricing (ELMP)," November 2011, https://www.misoenergy.org/Library/Repository/Communication%20Material/Strategic%20Initiatives/ELMP%20FAQs.pdf.

[469] PJM Interconnection, *PJM's Evolving Resource Mix and System Reliability* (PJM Interconnection, March 2017), 6, http://www.pjm.com/~/media/library/reports-notices/special-reports/20170330-pjms-evolving-resource-mix-and-system-reliability.ashx.

[470] Energy Information Administration (EIA), *Direct Federal Financial Interventions and Subsidies in Energy in Fiscal Year 2013* (Washington, DC: EIA, March 2015), xix, https://www.eia.gov/analysis/requests/subsidy/pdf/subsidy.pdf.

[471] Lawrence Berkeley National Laboratory, internal analysis for the Department of Energy, June 2017.

[472] N. Kumar, P. Besuner, S. Lefton, D. Agan, and D. Hilleman, *Power Plant Cycling Costs* (Golden, CO: National Renewable Energy Laboratory, April 2012), iv, http://www.nrel.gov/docs/fy12osti/55433.pdf.

[473] The National Coal Council, *Reliable & Resilient, The Value of Our Existing Coal Fleet: An Assessment of Measures to Improve Reliability and Efficiency While Reducing Emissions* (Washington, DC: National Coal Council, May 2014), 3, http://www.nationalcoalcouncil.org/reports/1407/NCCValueExistingCoalFleet.pdf.

[474] N. Kumar, P. Besuner, S. Lefton, D. Agan, and D. Hilleman, *Power Plant Cycling Costs* (Golden, CO: National Renewable Energy Laboratory, April 2012), iv, http://www.nrel.gov/docs/fy12osti/55433.pdf.

[475] N. Kumar, P. Besuner, S. Lefton, D. Agan, and D. Hilleman, *Power Plant Cycling Costs* (Golden, CO: National Renewable Energy Laboratory, April 2012), iv, http://www.nrel.gov/docs/fy12osti/55433.pdf.

[476] Steven A. Lefton and Douglas Hilleman, "Make Your Plant Ready for Cycling Operations," *Power Magazine*, August 1, 2011, http://www.powermag.com/make-your-plant-ready-for-cycling-operations/.

[477] Nikhil Kumar, "Should You Care about Power Plant Cycling?," *Intertek* (blog), http://www.intertek.com/blog/2012-12-26-power-plant-cycling/.

[478] Electric Power Research Institute (EPRI), *Fossil Fleet Transition with Fuel Changes and Large Scale Variable Renewable Integration* (Palo Alto, CA: EPRI, March 2015), https://www.epri.com/#/pages/product/000000003002006517/.

[479] The National Coal Council, *Reliable & Resilient, The Value of Our Existing Coal Fleet: An Assessment of Measures to Improve Reliability and Efficiency While Reducing Emissions* (Washington, DC: National Coal Council, May 2014), 3, http://www.nationalcoalcouncil.org/reports/1407/NCCValueExistingCoalFleet.pdf.

[480] Debra Lew, "Coal/Gas Plant Cycling: Costs, Causes, Impacts" (presented at Harvard Electricity Policy Group, March 11, 2016), https://www.hks.harvard.edu/hepg/Papers/2016/March%202016/Lew%20Presentation.pdf.

[481] NREL, "Power Plant Cycling Costs", April 2012, Accessed August 2017, https://www.nrel.gov/docs/fy12osti/55433.pdf

[482] U.S. Nuclear Regulatory Commission, input to Department of Energy request for information, "Addressing Policy and Logistical Challenges to Smart Grid Implementation," 75 Fed. Reg. 180,57006–57011 (2010), https://www.gpo.gov/fdsys/pkg/FR-2010-09-17/html/2010-23251.htm.

[483] D. T. Ingersoll, C. Colbert, Z. Houghton, R. Snuggerud, J. W. Gaston, and M. Empey, "Integrating Nuclear and Renewables," *Nuclear Engineering International Magazine*, February 1, 2016, http://www.neimagazine.com/features/featureintegrating-nuclear-and-renewables-4795860/.

[484] Dave Schmalzer, *An Analysis of the Power Plant Cycling Phenomena*, May 29, 2017 draft (Argonne National Laboratory, forthcoming).

[485] Revis James, Stephen Hesler, and John Bistline, *Fossil Fleet Transition with Fuel Changes and Large Scale Variable Renewable Integration* (Palo Alto, CA: Electric Power Research Institute, September 2015), DOE-EPRI-OE0000614, 4-38–4-39, https://www.osti.gov/scitech/servlets/purl/1224949.

[486] Energy Information Administration (EIA): "Monthly Update to Annual Electric Generator Report," March 2017, https://www.eia.gov/electricity/data/eia860m/; and internal analysis, June 2017