U.S. DEPARTMENT OF ENERGY
Office of Electricity Delivery & Energy Reliability

# Electric Power System, Markets and Reliability Study

## Interim Draft Report

July 2017

Prepared by U.S. Department of Energy

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# 1 Introduction

Secretary Rick Perry issued a memorandum on April 14, 2017, directing preparation of a study that examines whether recent problems associated with baseload power plants may be putting the nation's energy security and reliability at risk.[a] The memo notes that many baseload plants have retired, and asks whether these retirements are premature and whether they reduce grid resilience. It asks why so many baseload plants have closed, whether wholesale energy and capacity markets are adequately compensating important resilience and reliability attributes, how electric markets have evolved, and whether regulatory burdens, subsidies and mandates have forced premature retirements. The Secretary directs the Department to conduct rigorous analysis to answer these questions and to recommend sound policies to protect the nation's electric grid.

The Secretary's memo articulates several goals for the study and the power system as a whole: American families and businesses deserve a power system that is affordable, supports national security through fuel diversity and fuel assurance, and is technologically advanced, resilient, reliable and second to none. These goals will be discussed further below.

The memo raises important and timely questions about the electric grid. Those questions can only be answered by recognizing that generators and the grid are part of a larger electric power system, viewing the retirements story not just as a battle between generators, transmission owners and fuel sources, but also including customers and their options and preferences along with the supply side. Many of the technologies that we use to produce and consume electricity and energy have changed extensively over the past twenty years. These changes have caused great disruptions to the legacy resources and assumptions that formed the bulk power system we operate today. The questions here are as much about how to deal with and manage broad technological and economic change for a critical national infrastructure as they are about whether the erosion of baseload power plants threatens grid reliability.

The problems affecting baseload resources today reflect the broader challenge of how the energy industry can constructively manage change as technologies and economic relationships evolve.

Because the above goals may conflict and require delicate balancing by policymakers – for instance, high levels of reliability can become expensive, which works against affordability. Given growing levels of uncertainty and volatility from technology, finance, world threats, environment, etc., it is prudent to compile diverse portfolios that can provide a variety of important attributes. Secretary Perry's memo essentially asks how we should go about building such portfolios, and directs us to understand the consequences for the nation's electric resource portfolio options as significant amounts of coal and nuclear resources become unavailable to serve in current and future portfolios.

The stakes are high around these issues because electricity is so crucial to modern society and economic activity, and because of the magnitude of the industry and its capital and revenues. 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

[a] The Secretary's memo is attached in Appendix A.

distribution utilities[6] delivering electricity to 148.6 million customers.[b] [7] The total amount of money paid by end users for electricity in 2015 was about $400 billion.[8] This drives an $18.6 trillion U.S. gross domestic product and significantly influences global economic activity totaling roughly $80 trillion.[9]

## 1.1 Study Outline

Chapters 1 through 0 of this study provide the analytical framework, relevant data about the power system and generation retirements, and lay out the research and findings about baseload power, reliability, resilience and renewables.

Secretary Perry asked for specific recommendations for how to address and resolve these issues. Since there are many paths that could be taken from here, for many actors besides the federal government, Chapter 0 offers a comprehensive catalog of actions that could be undertaken. This section is intended to inform and motivate further discussion and action within and across the electric stakeholder community.

Outline here

Chapter 0 recommends specific actions and measures that can be undertaken immediately to address the most pressing issues identified in this study. Some of these actions fall within the scope and authority of the Department of Energy. However, some recommendations point to broader solutions that the Department cannot enact alone.

The Appendices contain the following information:

- Appendix A contains Secretary Perry's April 14 memorandum, which initiated this study.
- Appendix B lists all of the power plants in the Energy Information Agency's database that have retired in the United States since 2000.
- Appendix C lists all of the major U.S. statutes and regulations that have affected electricity supply and demand.
- Appendix D contains an extensive set of tables and graphics that support the information provided in the body of this report.
- Appendix E lists all of the technical reports and studies that the Department of Energy and its national laboratories have prepared since 2012 on topics relating to the issues addressed in this study.
- Appendix F offers a set of technical references for those who wish to learn more about the topics addressed in this study.

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

### Excluded from this study

Several topics are not addressed in this study, for the reasons explained here.

Cyber-security is the common potential failure mode that affects every part of the American power system – every power plant, every transmission and distribution system, every user and many end use devices are at risk from existing and emerging cyber-security threats. Because the cyber-security problem is ubiquitous, this study does not address cyber-security because it does not have any unique relevance or impact on baseload power plant retirements, renewables, and power system reliability.

Alaska & Hawaii -- The analyses that follow do not directly address the oil, coal and gas plants in Hawaii and Alaska. Those plants are small plants that fall below the size screens used in this study, and the Hawaii and Alaska power systems are remote, vertically integrated systems with special needs and issues. While the broad trends discussed in this study apply in Hawaii and Alaska as well as on the mainland United States, many of this study's economic observations do not directly apply to the specific situations in the Hawaii and Alaska power systems.

Geothermal, oil and biomass steam generation – Geothermal, oil and biomass power plants are often operated as baseload plants, operating at a relatively stable level over a long period of time. Since these types plants are not as prevalent or widespread as gas, coal and nuclear plants, such units are not examined in this study.

## 1.2 Findings of this study

Based on an extensive review of electric power system evolution and events over the past thirty years, and analysis of DOE and other data sources using basic supply and demand principles, this study concludes that:

- Functionality, not technology -- Baseload power plants should be defined in terms of functionality rather than fuel or technology. Baseload plants are those dispatched to serve customers' base (minimum) load. These plants are operated within a relatively fixed operational zone over an extended period of time (days or weeks), with limited cycling or ramping capability. The generating technology types that meet this definition include coal, nuclear, gas-fired steam and combined cycle plants. (See Section 2)
- Many baseload plant retirements are not premature. Since 2002, most baseload power plant retirements have been the victims of overcapacity and relatively high operating costs that often reflect the advanced age of the retiring plants. Many of these retired plants had already complied with some of the environmental regulations implemented under statutes enacted between 1970 and 2001, but had not yet complied with the later requirements imposed by these regulations. Furthermore, the first tranche of fossil plant retirements occurred before the explosive growth of renewable generation over the past five years. Many of the on-going stream of plant retirements have been driven by the combination of low natural gas price-based electricity prices, low electric demand, environmental regulations, state policies, and competition from renewables. In other words, many retirements are consistent with observed market forces. (See Section 3)
- Some baseload plant retirements have been premature relative to their design life and operational efficiency. Costly environmental regulations and subsidized renewable generation

have exacerbated and accelerated baseload power plant retirements. However, those factors played minor roles compared to the long-standing drop in electricity demand relative to previous expectations and years of low electric prices driven by high natural gas availability. (See Section 3.12)

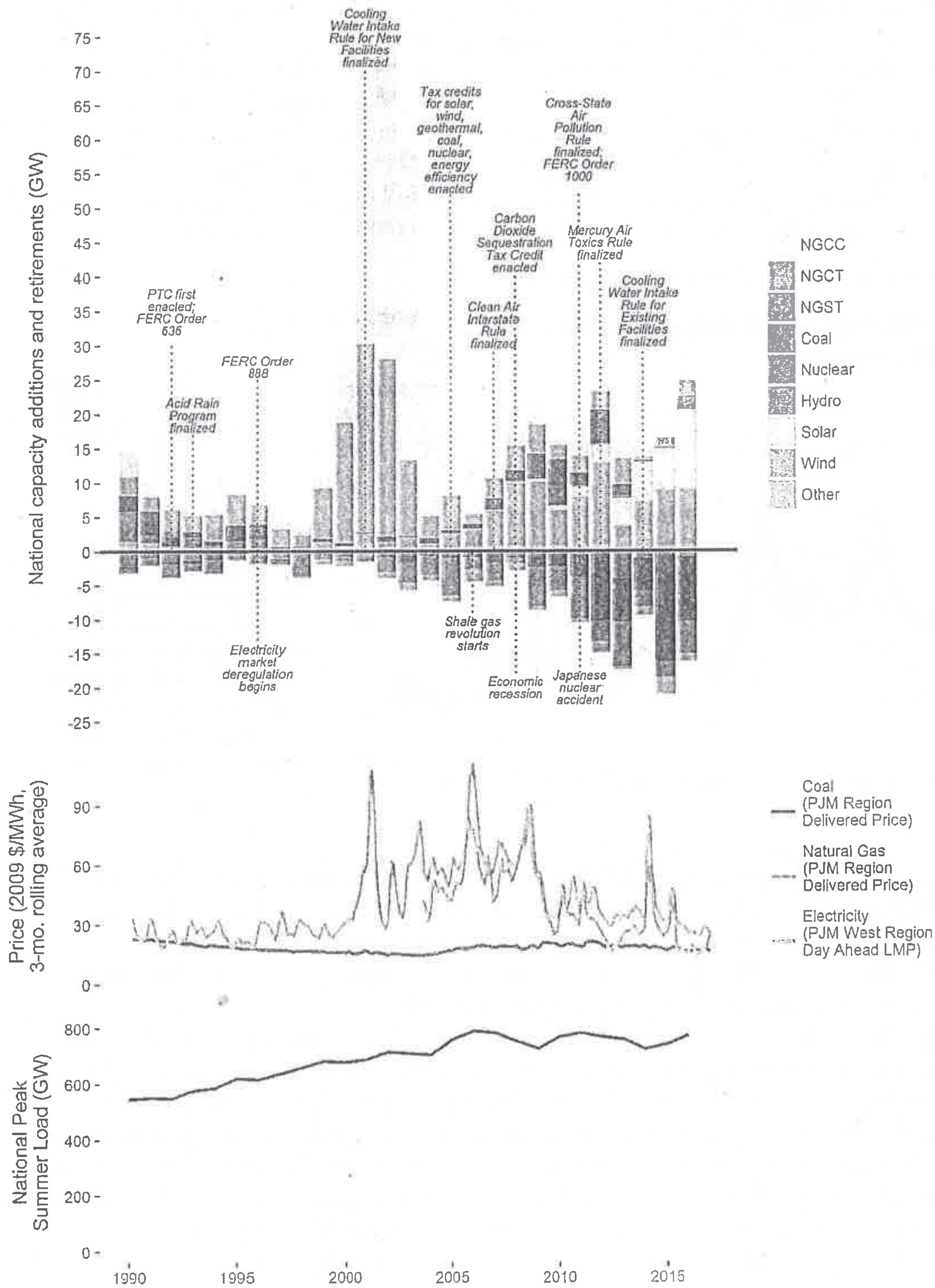
- Baseload history -- Most baseload plants were built between the 1950s and 1990s under cost-of-service regulation, where regulators approved the construction and on-going cost-pass-through for "prudent" utility-recommended plants. Vertically integrated utilities built increasingly larger coal and nuclear plants using contemporaneous technologies to capture economies of scale and efficiency, and marketed any excess power to their neighbors. After Congress committed the nation to allow new third-party generator entrants (PURPA, 1978) and to mandate open access to the transmission system (EPACT, 1992), FERC implemented regulations encouraging the formation of centrally-organized wholesale markets. Many of the older baseload plants were forced to compete in these open markets against lower-priced generators. While the owners of these assets enjoyed profits associated with high wholesale prices for several years, by 2005 many of the older baseload plants had been sold to independent power producers and lost the protection of rate-based status and the opportunity to earn a specified rate of return. Many inefficient plants retired in those years. Even those plants still owned by integrated utilities are having to compete against third-party and market opportunities as state regulators and abundant low-cost power opportunities push utilities to acquire more cost-effective power portfolios. (See Section x)

- Retirement history -- The retirement of baseload power plants has accelerated since 2009. (Figure 1.2) Baseload retirements correlate closely to the fall in natural gas prices and the flattening of customer peak demand.

Add labels in graph in high white space above X axis (Capacity additions) and low below (capacity retirements)

Modify graphic to shrink middle right legend so main graphic gets more real estate

275 **Figure 1.1. Timeline of Electric Generating Capacity Additions and Retirements, Tax Incentives,**
276 **Orders and Regulations, Regional Market Prices, and Load[c10]**

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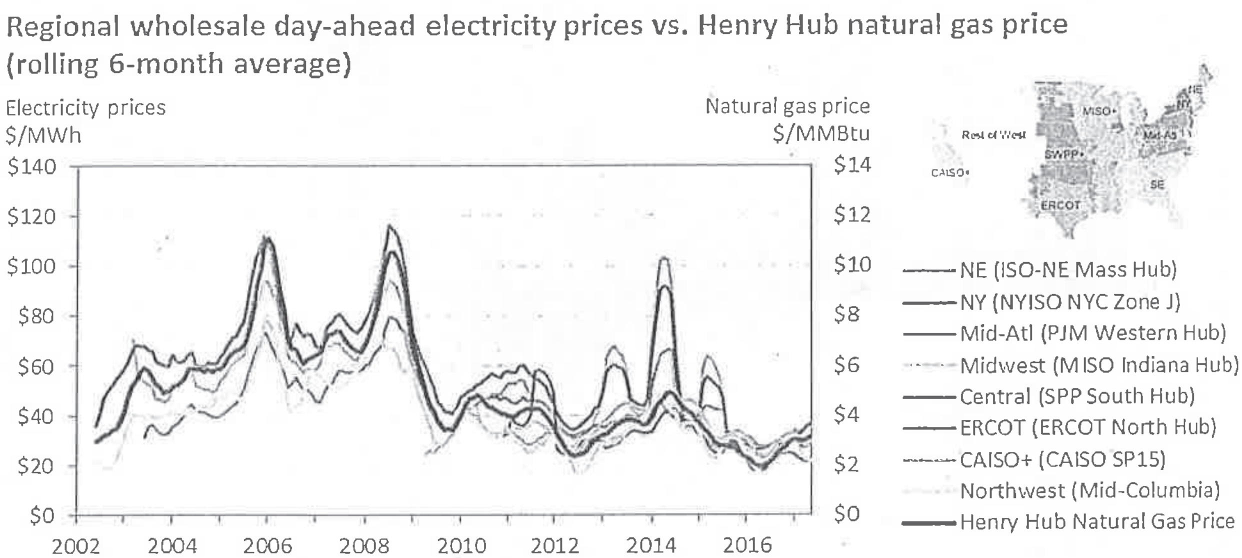
[c] (Top) Implemented federal legislation and regulations are shown on a timeline with national changes in electric generating capacity and compared against (Middle) Regional market prices for the PJM region, and (Bottom) Summer peak electric demand. The type and quantity of capacity additions and retirements have changed notably

- Growth of natural gas-fired generation -- While coal and nuclear power plants used to provide the bulk of America's electricity, wholesale electricity prices have closely tracked natural gas prices for the past 15 years. (Figure 1.2) The fact that new, high-efficiency natural gas plants and the pipelines that serve them can be built quickly helped to grow gas-fired generation relative to coal and nuclear power. After unconventional production techniques for oil and gas entered the scene in 2007, natural gas prices began falling and have stayed low. As a result, newer, more flexible gas-fired plants began driving down market-clearing electric prices in 2009, under-cutting the higher production costs of older coal and nuclear generators. (See Section x)

**Figure 1.2. Electricity prices track natural gas prices[11]**




- Renewables didn't cause retirements, but they've exacerbated the problem – Baseload plant retirements due to age, inefficiency, and inability to compete began appearing in the early 2000s, well before any significant levels of wind and solar generation in any region of the country. But starting around 2007, variable renewable generation (VRE) – particularly wind and solar – have grown quickly, accelerated by the favorable effects of state Renewable Portfolio Standards (RPS) and the subsidizing effects of federal tax credits. Because VREs are neither fully controllable nor predictable, but very low-cost, they have displaced other generation and forced a change in the way operators manage the grid. Current levels of wind and solar penetration are reducing the level of net baseload generation and requiring affected regions to demand that all power plants operate with greater flexibility and provide essential reliability services such as frequency response, cycling and ramping. While baseload plants provide valuable inertia that helps with frequency regulation, most coal and nuclear plants are not capable of flexible ramping and cycling and cannot beak even operating at lower capacity factors.

over the past decades. Technology costs (not shown), fuel prices, tax incentives for various generating technologies, market deregulation, environmental regulations mainly to protect air quality, but also water quality, weather and economic events, efficiency and age of the generating fleet (shown elsewhere), and flattening of electricity demand have all contributed to the change in electric generating capacity. Note: this graphic does not quantify the impact of various market effects and policies on electric generating capacity.

- Each retirement decision is unique to a particular situation. But every retirement decision reflects the owner's assessment of whether that plant will be produce enough energy, paid at high enough prices, to recover the costs of its fuel, operations and capital requirements, including potential new capital investments. Over the past decade, many power plant owners have concluded that plants with higher heat rates, limited ability to operate flexibly, and that need capital improvements to meet environmental regulations, will not be able to earn adequate revenues in wholesale electric markets that select and dispatch resources based principally on short-run marginal costs. Many of the coal retirements in 2015 in particular were prompted by decisions about whether the costs of investing in a plant to comply with MATS regulations would ever be recovered given market prospects for continuing low demand and low prices, or close the plant to avoid that investment. Similarly, the timing of some nuclear retirement decisions appears to be related to nuclear relicensing and regulatory compliance schedules. Environmental regulatory requirements may have been the straw that broke a baseload camel's back -- particularly for coal plants – but it appears that most baseload plants were already burdened by the effects of low natural gas prices, eroding customer demand, and lower capacity factors before the incremental burden of new regulations tipped the balance over to retirement. (See Section 3)

- Regional factors drive retirements – Coal and nuclear assets tend to be concentrated in a few regions of the country, as are wind and solar development. (Figure 1.3) Baseload plant retirements tend to be concentrated in areas that moved to wholesale and retail electric competition earlier, and came later to regions that remained under vertical integration and full cost-of-service regulation. Therefore, the retirements challenge is concentrated in the Northeast and the Mid-Atlantic rather than nationwide, while the challenge of managing high penetrations of renewable generation is concentrated in Texas, California, the Southwest and Midwest.

**Figure 1.3 Baseload plant retirements vary by region**[12] [13] [d]

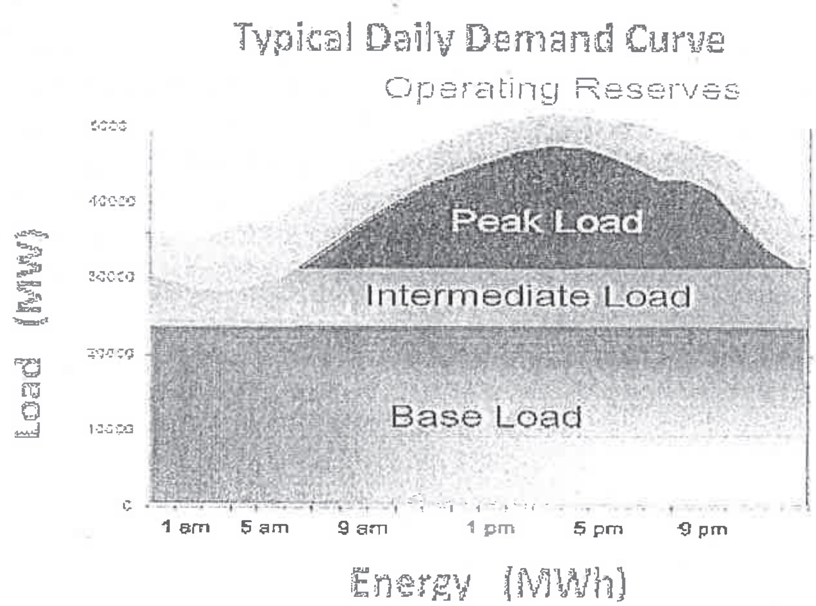
[d] Generator units larger than 50 MW of net summer capacity. The Other category includes a combined 936 MW of biomass, wind, petroleum coke, and syngas from petroleum coke. Retirements reflect regional fuel use and historic concentrations of power plants.

# 2 Assessing baseload resources

The electric industry refers 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 shown in Figure 2.1. Baseload plants have high capital and operating costs but – until recently – have low fuel costs and good fuel efficiency. Although the output level of these plants can be changed, they are most economical when operated at near-full capacity at all times. Large baseload units have longer start-up and shut-down times (cycling) and must move slowly between production levels (cycling) to avoid damaging plant components with thermal stress or metal fatigue.

Large nuclear, coal-fired, natural gas-fired steam and run-of-river hydroelectric plants have historically been used for baseload generation. With the recent drop in natural gas prices, it has become more economical to use natural gas-fired combined cycle plants as baseload generation.

**Figure 2.1. Schematic of customer daily load curve showing base load[16]**




Intermediate or mid-merit plants are used to follow load, meeting daily variations in demand. Natural gas combined cycle plants have traditionally been used for load-following. Peaking generators (mostly gas turbines which are low-cost to build but have high heat rates) and customer-provided demand response are dispatched infrequently to meet extreme spikes in demand. Appendix D contains D-1, a description of the types of power plants, and D.2, a description of how generators are selected (dispatched) to produce electricity.

For this study, DOE defines baseload generators as plants that are operated in the pattern of baseload generation described above – they were operated for many years to run at high, sustained output levels and high capacity factors with minimal cycling or ramping. While this definition includes most nuclear, coal and gas-fired steam generators, it is not a given that every nuclear, coal-fired or gas-fired steam generator is a baseload plant.

NERC draws a distinction between baseload generation and the characteristics of generation providing reliable baseload power[17]:

> Coal and nuclear resources, by design, are designed for low cost O&M 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 [bulk power system].

Power plant cycling

With increased variable renewable energy generation and lower electricity demand, all power plants have had less ability to run in a baseload generation pattern and have been asked to cycle and ramp more often. Plants that can't cycle or ramp will operate less, earning less revenue and possibly becoming unprofitable. GE, a major power plant manufacturer, reports that cycling costs are one to seven percent of overall fossil plant construction cost and that the average fossil-fueled plant sees an O&M cost increase of $0.47 to $1.28 per MWh produced. GE observes that:

- 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 have different impacts on cycling.[18]
- Operational and/or physical changes to coal/gas plants can increase flexibility. Retrofits have the potential to increase overall profitability.[19]

The cycling issues described above have similar impacts on gas-fired steam and older combined cycle generators. [also nuclear?]

## 2.1 Applying the baseload generation definition

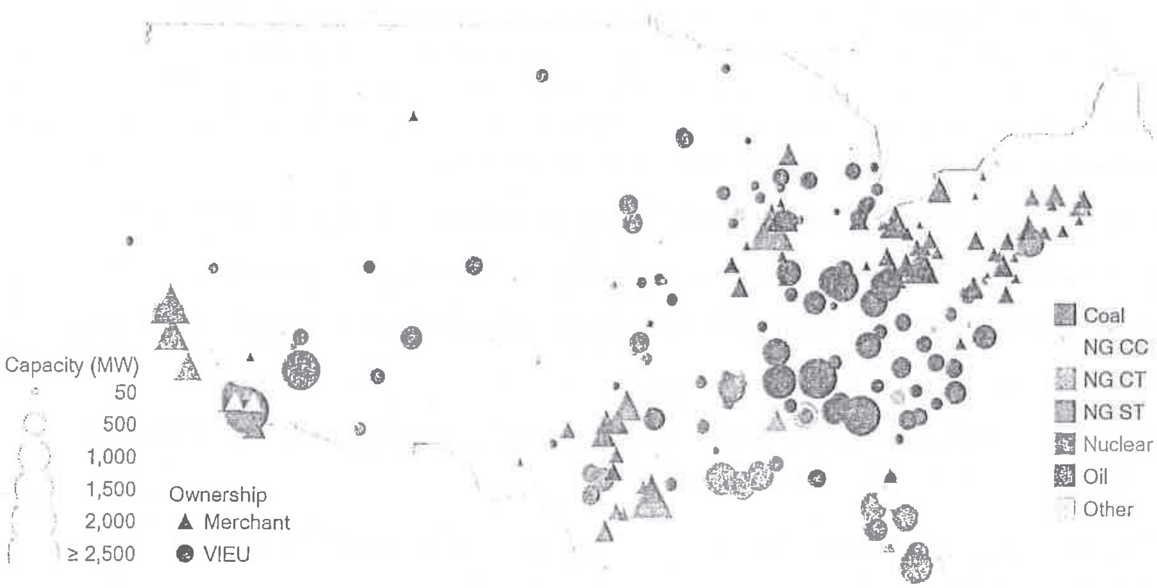
[UNDER CONSTRUCTION – NEW EIA MATERIAL]

## 2.2 Baseload generation – looking forward and next steps

# 3 Baseload plant retirements – what retired and why

As Figure 3.1 shows, the baseload retirements issue is essentially a regional issue – types of plants and capabilities vary by region, as do the magnitude and timing of retirements. This section opens with an overview of power plant retirements nationwide, then looks at the reasons why baseload plants are retiring – the causes are a stew of market-affecting factors including low natural gas prices, wholesale competition, the flattening of customer demand, cost increases relating to regulation, the growth of renewable generation devaluing baseload generation in favor of greater flexibility, and the decision-forcing effects of regulatory deadlines.

**Figure 3.1. Map of baseload (coal, nuclear, gas thermal, hydro) retirements**

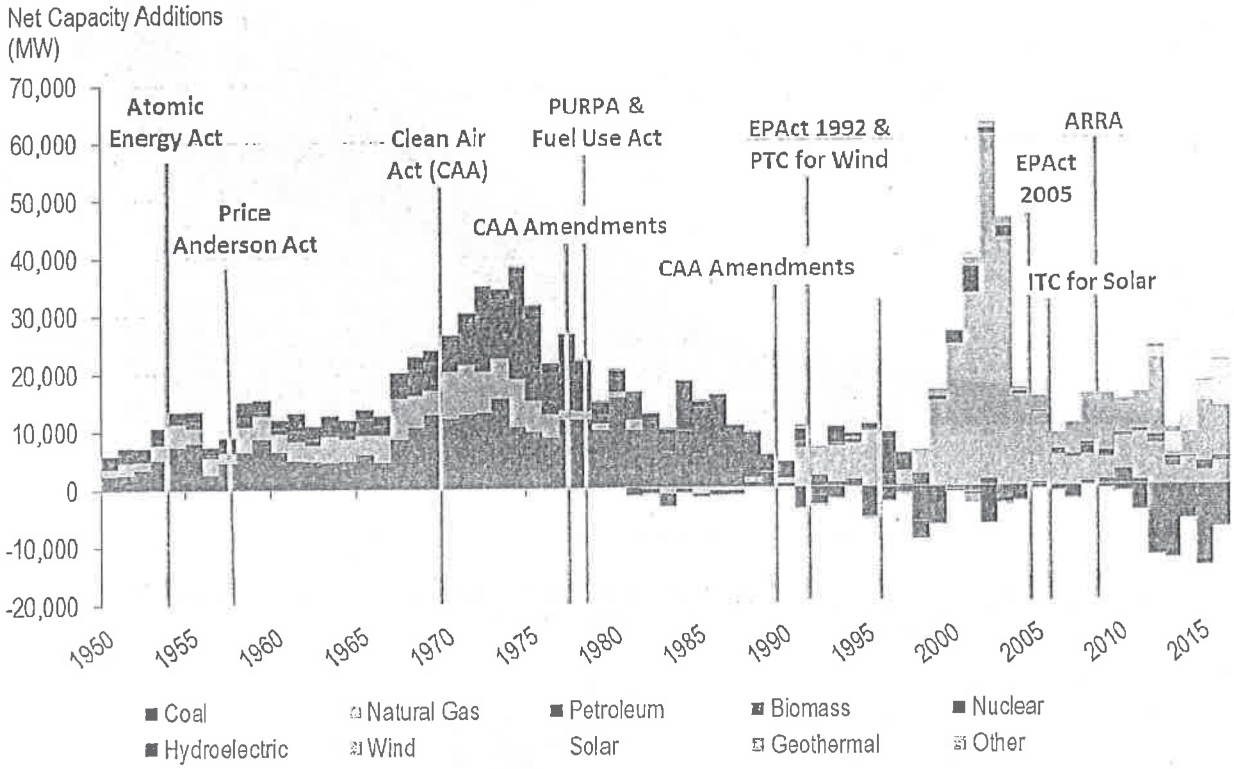



Location of Coal, Natural Gas, Nuclear, Petroleum, and Other Generating Plant Retirements by Ownership and Fuel Types, January 2002 – March 2017[20 21]

## 3.1 Overview -- power plant retirements since 2000

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

**Figure 3.2. Net Generation Capacity Additions and Retirements.[22] (Source: QER Updated Figure 1-1)**




Similar policies and developments that drove waves of power plant construction similarly drove retirements over the last two decades, with power plant age and technology vintage an important factor in plant retirement patterns.

Power plant retirements are nothing new – significant generation retirements in the current age began in 2002, and have accelerated since, as shown in Figures 3.3 and 3.4. Retirements have been due primarily to flattened demand and low electric prices and the inability to compete successfully due to plant age, inefficiency and capital needs rather than regulatory burdens. Retirements of baseload plants (gas thermal, coal, hydro and nuclear) have been going on for at least 15 years.

**Figure 3.3. Cumulative Retirements of Utility-Scale Electricity Generation Capacity January 2002 – March 2017, and Announced Retirements April 2017 – December 2022[23][24]**

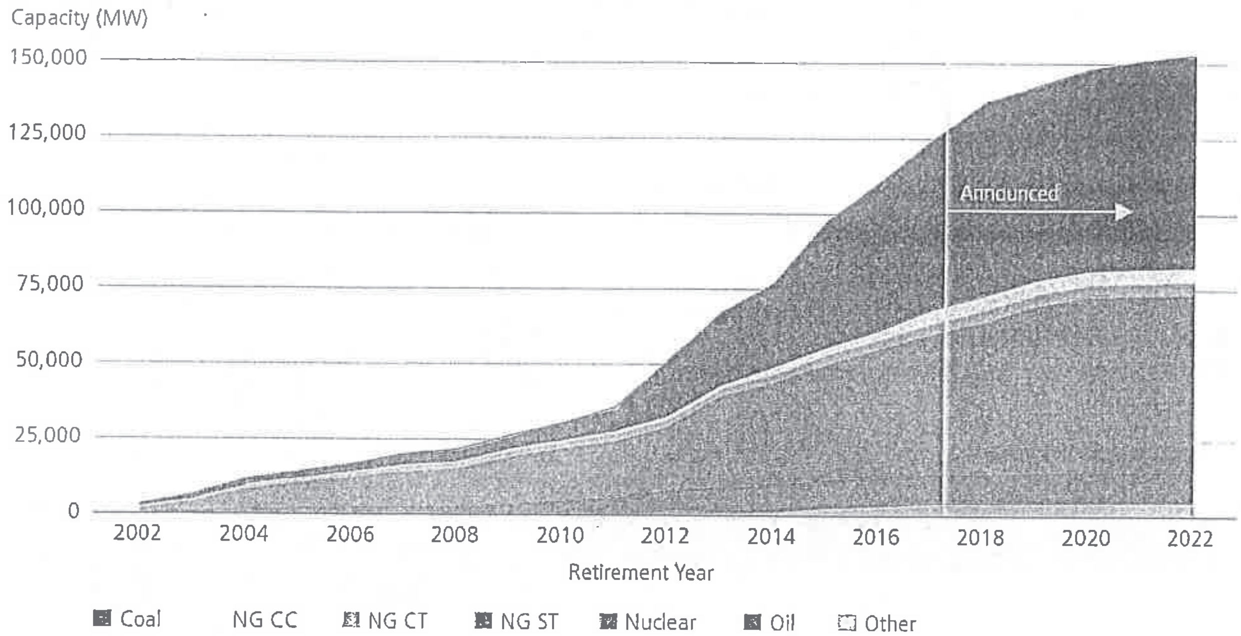
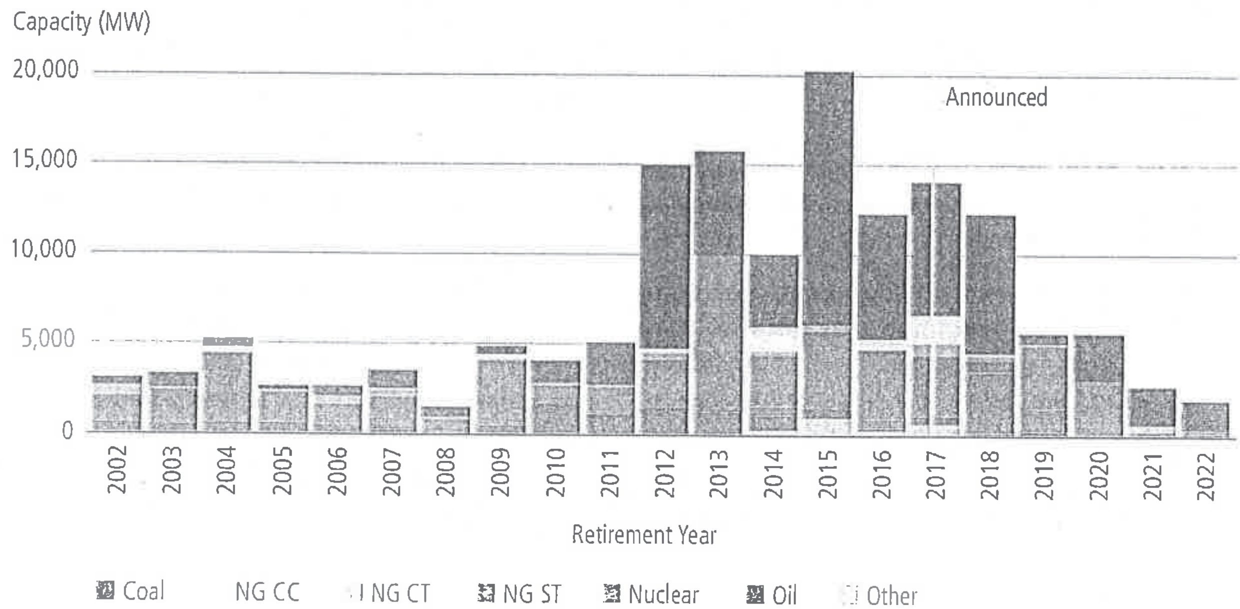



**Figure 3.4. Historic and Announced Annual Retirements of Coal, Natural Gas, Nuclear, Petroleum, and Other Generating Units, January 2002 through December 2022**[25 26]




Why plants retire

A power plant owner decides whether to retire a plant based on rational expectations of whether the owner can recover sufficient revenues to justify continued operation.

Add explanation of the elements of a decision whether to close a power plant – forward-looking, how many years time horizon, whether there's expected demand, anticipated prices, expected capital, operating, fuel costs, your competitiveness against other resources. How long does it take to execute a retirement decision? Forcing effect of a regulatory deadline (hydro relicensing, nuclear relicensing, environmental compliance deadline) on when you start the analysis, when you make the decision and how long you keep running the plant.

Regulators imposing IRP and pushing for least-cost resource portfolios (Midwest and some other vertically integrated states, Hawaii) have been the cause of some recent VIEU abandonments for portfolio restructuring.

A review of coal, nuclear and natural gas retirements to date (2002 through May 2017) shows that baseload plant retirements are a regional issue, reflecting regional patterns of generation development, affecting different regions in very different ways. Statement about region with most MW retired. Most of the power plants retired were 40 years old or older by their retirement date. And most retirements are concentrated in the East where more plants were built earlier, to serve larger populations (Figure 3.5).

**Figure 3.5. Generating Unit Retirements by Region, Unit Age, Ownership, and Retirement Year, January 2002 – March 2017**[27 28]

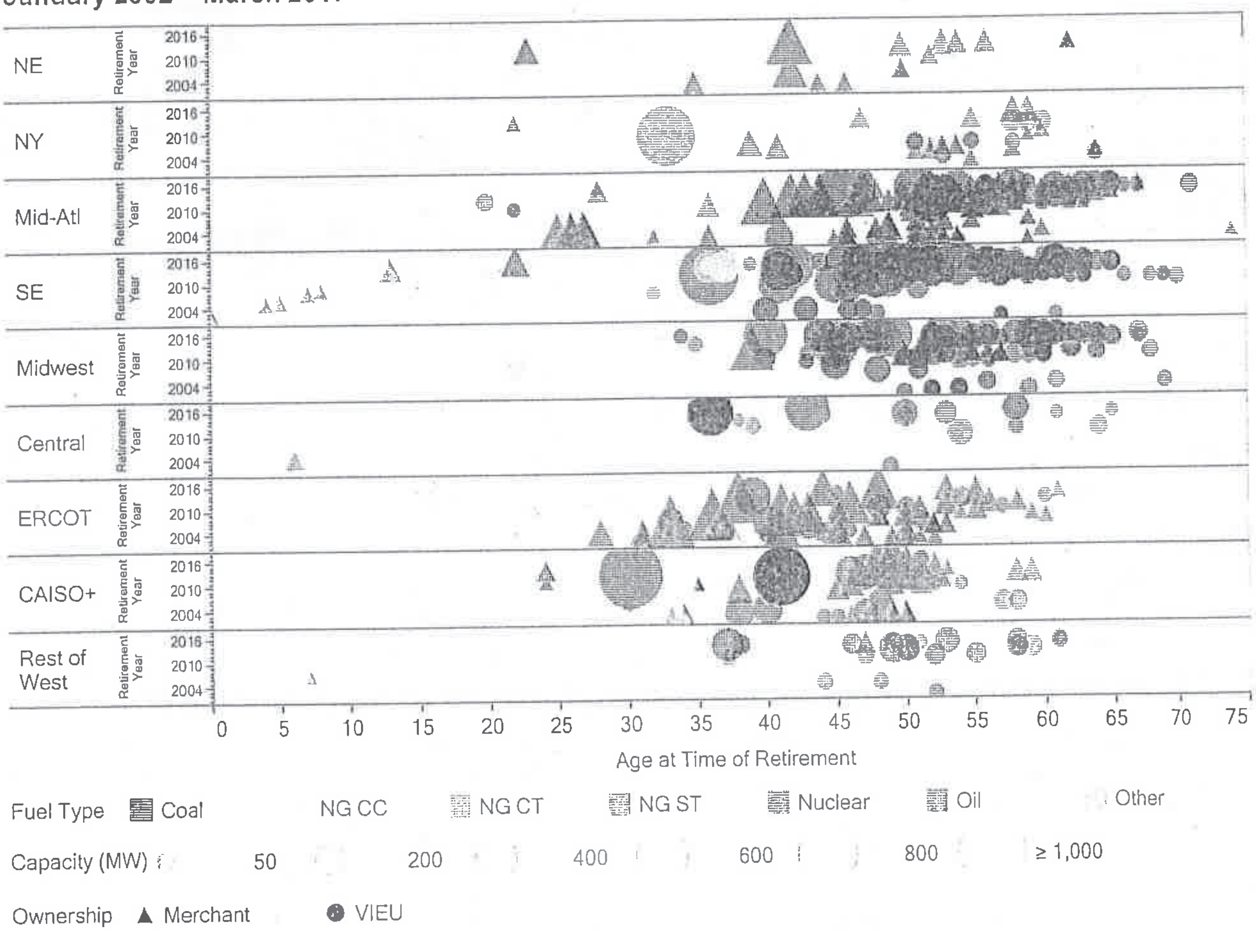



Figure 3.6 focuses on the year of power plant retirement. This is important because a variety of economic trends and regulatory events occurred in different periods over the 2002 through 2016 period. This figure shows that merchant plants made up the majority of the baseload plants that retired in the 2002 through 2011 period, because those plants were more directly exposed to competitive wholesale market prices and more likely to exit the market quickly if a plant was losing money. Generators that have long-term bilateral PPAs or are utility-owned self-supply (same LT PPA contract) gets exposed to true market prices much later than merchant plants competing for only short-term bilateral contracts or in spot market.

**Figure 3.6: Generating Unit Retirements by Region, Ownership, Capacity, and Fuel Type, January 2002 – March 2017[29 30]**

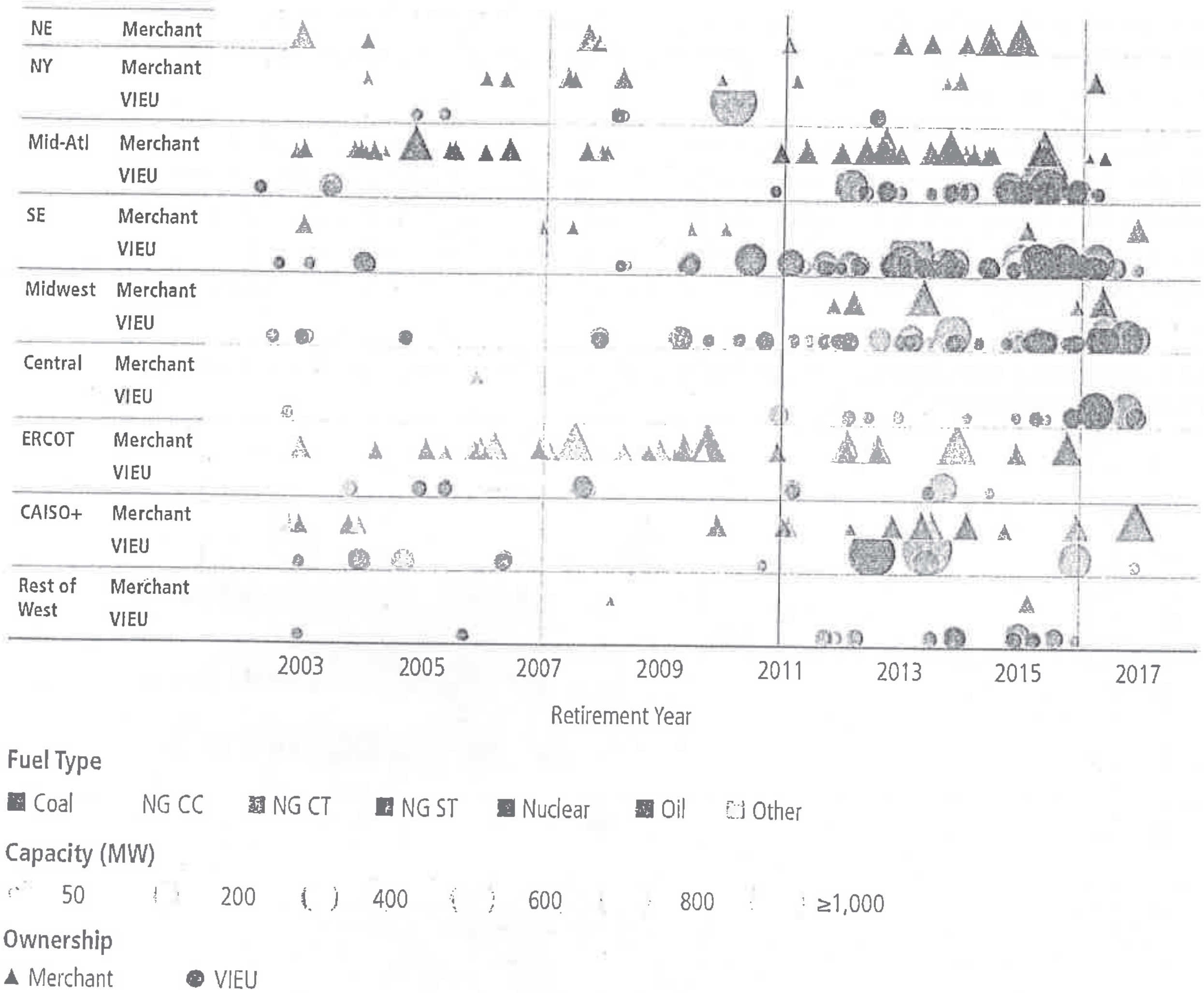



**Figure 3.7: Power Plant Retirements by Retirement Period, January 2002 through March 2017[31 32]**

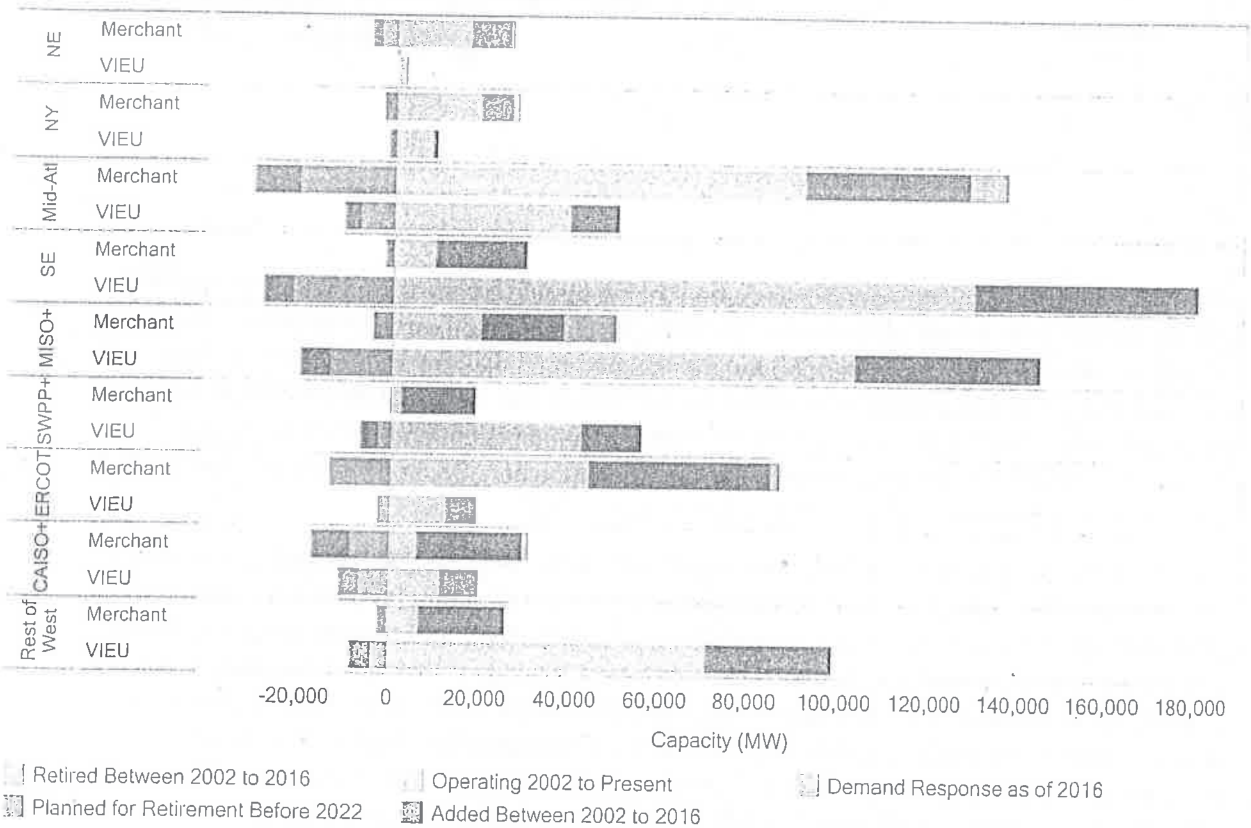

Figure 3.7 shows:

- The 2002 through 2005 period was when the wholesale competition initiated in the late 1990s got underway, with forced utility (called Vertically Integrated on these charts) power plant divestiture moving a number of power plants into merchant ownership in California, Texas, and the mid-Atlantic states in particular. Most of the retirements that occurred in this period were of smaller, older merchant power plants that were inefficient and borderline uneconomic before a utility owner sold it to the new merchant owner. Most of these retirements occurred in centrally-organized markets, particularly PJM and ERCOT.
- The period from 2006 through 2011 saw some early environmental regulations begin to affect the coal fleet, the early growth of utility-scale wind generation, the economic recession from 2008 through 2011, and the start of the shale gas boom in 2008 with natural gas prices starting a downward trend a decade ago. Old, inefficient natural gas-fired plants retired early in this period, but the fall in natural gas prices starting in 2009 began to force the shut-down of smaller, older coal plants and older oil plants in 2009 through 2012. At the same time it became clear that a portion of the customer electricity demand lost from the recession was not going to reappear, which meant that higher demands would not absorb more costly electric production at higher levels on the energy supply curve.
- In the period from 2012 through 2015, it became clear that low natural gas prices were probably a long-lasting trend rather than a short-term phenomenon. And this was the period when the compliance deadlines for a number of environmental regulations, initiated under several different statutes, all converged. This is the period with the most baseload plant retirements, with a marked increase in California, the mid-Atlantic, Midwest and Southeast. Most of these plants were rendered uneconomic and uncompetitive low-priced natural gas-fired generation, in a significantly flattened supply curve meeting a lower demand curve. The 2015 MATS compliance deadline was the last of these deadlines, so many of the retirements in this period were of plants whose owners chose to shut down a plant rather than invest in one or multiple costly environmental remediation measures. (See Section 3.6 on regulation)

- In 2016 and 2017, going forward, on-going power plant retirements are those that have been rendered uneconomic by sustained low electric prices.

Figure 3.8 illustrates merchant and VIEU retirements from 2002 through 2016, announced retirements through 2022, generation capacity that was operational prior to 2002 and is still in operation, capacity that was added between 2002 and 2016, and demand response in 2016. Figure 3.8 shows generation capacity, additions, retirements, announced retirements, and demand response as a percentage of 2002 total installed capacity in each region. These graphics show that in every region, the proportion of retirements (in orange) is less than 20 percent of total capacity available, and that in those regions with a larger share of merchant generation, much more merchant capacity retired than vertically-owned utility plants.

**Figure 3.8: Operating Generation Capacity, Additions, Retirements, and Announced Retirements by Region, January 2002 – December 2022[33] [34]**




Other regional conclusions can be drawn from the above data:

- New England has not seen a high proportion of retirements. Their reliability concerns focus principally on gas-electric interdependence challenges rather than on a shortfall of baseload generation.

- ERCOT has experienced continued churn of its natural gas-fired generation fleet due to the combination of fierce wholesale competition, rock-bottom natural gas prices, and easy entry and exit to the generation market. Texas has experienced strong growth of renewable generation (principally wind), with enough new transmission built to remove the transmission constraint that protected most of the region's generation from the low and negative price levels set by wind and gas-fired generation in West Texas.

- Baseload retirements occurred later in the Southeast, Central, Midwest and West than they did in other regions. This is because those regions are dominated by vertically integrated utilities under traditional regulation, so the utilities could recover costs and capital returns on less economic plants for a longer period than merchant generators without ratebase protection and captive ratepayers. Regulators in many of these states also have utility-specific resource adequacy or reserve margin requirements, which would justify retaining a plant longer than its short-term economics might otherwise support.

## 3.2 Big picture – multiple causes compounded to force power plant retirements, changing the supply curve for electricity

There have been three statistical studies of the causes of baseload power plant retirements.

- The Columbia University Center on Global Energy Policy Study, "Can Coal Make a Comeback," (April 2017) found that 49% of the collapse of the domestic coal industry has been due to increased competition from high volumes of low-cost natural gas, 26% from lower-than-expected electricity demand, and 18% due to the growth of renewable energy.[35]
- The draft Lawrence Berkeley National Lab study, "Power Plant Retirements: Trends and Possible Drivers," (June 2017), found the strongest correlations to coal, nuclear and natural gas-fired plants lie with the diminishing load growth, high summer planning reserve margins (i.e., over-capacity), coal plants using high SO2 emissions rates (i.e., they needed more costly environmental upgrades), low natural gas prices, and advancing generator age.
- The Analysis Group study, "Markets, Reliability and the Evolving U.S. Power System," (June 2017), looked at the decrease in prices per MWh in the PJM market (since that decrease would go straight to a coal plant's bottom line) and concluded that of an almost $30/MWh price drop, $28.00 of the price decline was due to the decrease in natural gas prices, $1.00 was due to the drop in electric demand growth, and $0.39 would be due to new wind generation operating at full capacity.

More broadly, the data reviewed below indicate that retirements of nuclear, coal and natural gas power plants have occurred for several reasons, but have been driven principally by the effects of supply and demand upon old, inefficient power plants:

- Reduction of demand growth (peak and energy) since late 1990s and flattening of demand since 2008 have reduced the room for less competitive plants to make sales.

- The coal and most of the natural gas baseload plants that have retired are old and inefficient units that were not recovering their operations and fuel costs, much less capital cost recovery. Retirement decisions are based upon forward-looking expectations about whether a plant will be able to recover its costs and make a profit; since electric prices have been low for years, and are going lower, many coal and nuclear plant owners see little likelihood of earning full cost recovery from power market revenues alone.

- Merchant generators began retiring noticeable quantities of old, inefficient natural gas thermal and coal plants (baseload capacity) in the early 2000s. Vertically integrated electric utilities (VIEUs) began retiring more of these units after 2010, and the number of plants and MW retired has accelerated over recent years. Most of the retirements before 2013 were owned by merchant generators rather than vertically integrated electric utilities, and most of those retired plants were gas-fired. Merchant plants that are directly exposed to market prices without the protection of long-term self-supply arrangements or captive customers covering capital and operating costs, would be the first to close if they were not competitive against other sources.
- Electric energy prices across North America have been dictated by natural gas prices for over a decade. After domestic and international natural gas prices began falling with the success of shale gas and unconventional drilling, increased low-cost natural gas-fired generation began displacing inefficient coal and gas-thermal generation.
- A significant number of coal plant retirements occurred in 2015, the last year that a coal or plant needing to add pollution control equipment for MATS compliance could operate without investing in the required pollution control equipment.
- The growth in variable renewable generation after 2007 (earlier inside ERCOT) has exacerbated but did not cause the baseload retirements problem. (This is obvious from the fact that the Southeast has seen significant retirements in recent years, but has almost no renewable generation.) As shown in the ERCOT supply curve discussion, the low marginal cost of renewable production lowers the supply curve and thereby the market-clearing price available to all suppliers. At the same time, the variable output levels of renewable generators and the fact that they reduce night-time minimum load and change daytime peak and ramping requirements have reduced the opportunities for baseload plants to operate at sustained, high output levels. This leads to reduced dispatch of baseload units at lower prices, higher operating costs, and ultimately lower revenues insufficient to cover costs.

## 3.3 Cause -- electricity demand is lower than projected

Between 1970 and 2005, total U.S. electricity generation grew steadily at a compound annual growth rate (CAGR) of 2.7%. But since 2005, generation growth has stalled with a CAGR of only 0.05% from 2005 to 2015, even as the nation's gross domestic product grew by 1.3% per year over the same period. [EIA].[i] As Figure 3.9 shows, although electricity demand used to rise in parallel with economic growth (as measured by Real Gross Domestic Product), demand and GDP began decoupling around the year 2000. EIA attributes this fall in demand to a variety of factors including the impact of years of energy efficiency standards improving building and appliances and technology improvements in lighting and other end equipment, and broader economic factors such as a shift toward less electricity-intensive industries and slower population growth. [EIA AEO 2017] The factors affecting the slowdown in energy demand are shown in Figure 3.10. The dip in both GDP and electricity use in 2008-09 reflects the U.S.

[i] Note that this projected demand growth was not unique to EIA or the Annual Energy Outlook. Virtually every prominent projection of electricity demand included steady electricity demand growth.

recession, which lowered electricity usage enough to affect power plant economics and prompt some plant closures.

**Figure 3.9. Gross Domestic Product and Net Electricity Production, Historical (1950-2016) and Projected (2017-2027)[36 37 38 39] [Source: EIA, QER 1-28 updated][j]**

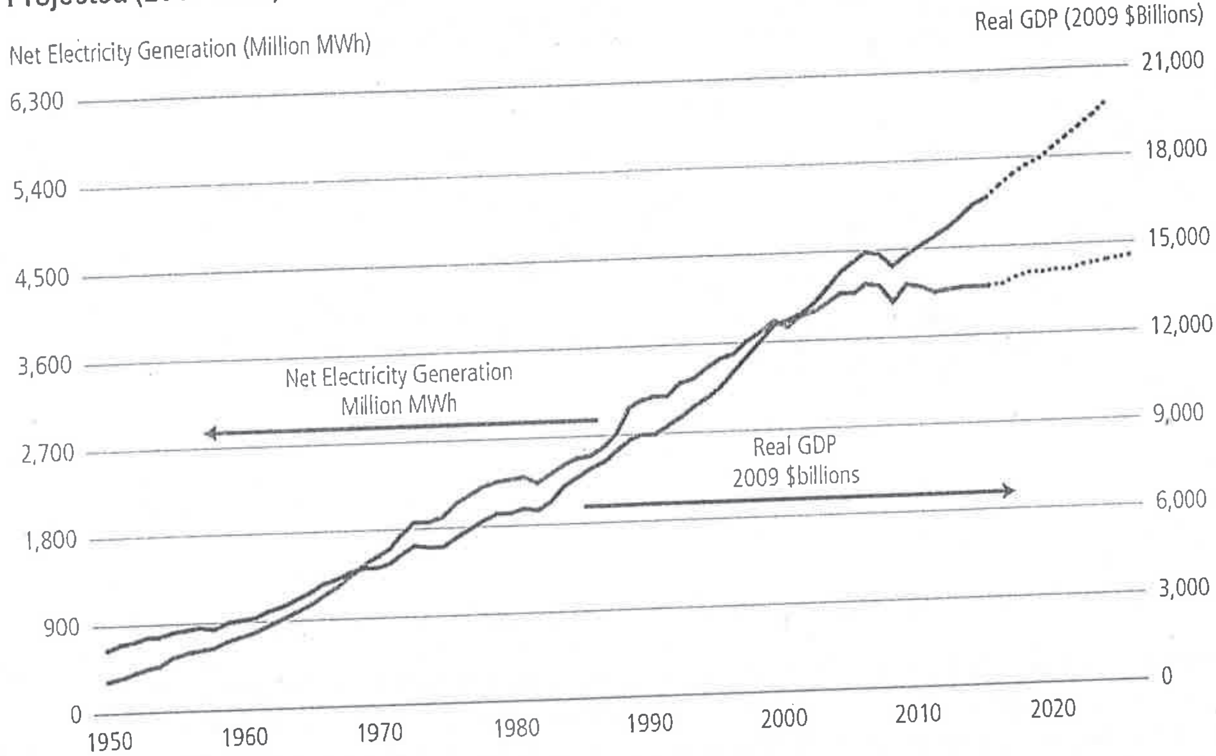



**Figure 3.10. Estimated U.S. Energy Savings from Structural Changes in the Economy and Energy Efficiency, 1980 to 2016.40 41**

[figure]

It is difficult to forecast customer electric usage accurately. As shown in Figure 3.11, the recent history of the EIA's Annual Energy Outlook customer electric use projections show that DOE's expert forecasters – as most other energy experts – have consistently over-estimated actual U.S. electricity usage (see the blacked dotted line at the bottom of this figure). EIA and many other forecasters have consistently over-estimated peak demand as well as energy over recent years.[k l]

---

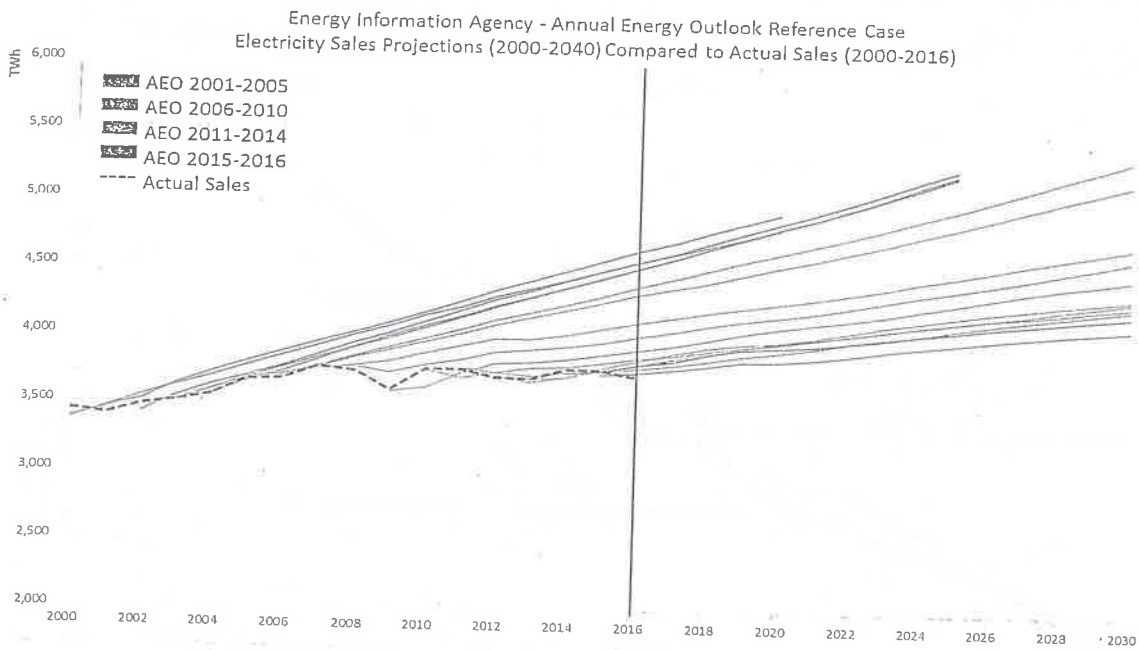
[j] Historically, from the 1950's to 1990's, electricity consumption and economic growth (measured here by real gross domestic product) have risen in parallel. Beginning in the 2000's, economic growth became decoupled from electricity consumption, as a result of continued progress in improved energy productivity across all economic sectors

[k] For instance, MJ Bradley & Associates' "Load Forecast Analysis" (August 24, 2016) reviewed a number of electricity demand forecasts over time and concluded that most forecasts overshot actual demand from 3 years out or farther, but improved in recent years and as the horizon between forecast and actual use year shortened. (http://www.mjbradley.com/sites/default/files/MJBA_LoadForecastAnalysis_FINAL_0.pdf)

[l] Over-estimating customer demand can have significant market impacts. During the 2000-2001 California electricity crisis, the electric utilities consistently overstated the amount of electricity that they wanted to purchase from the California Power Exchange, and then under-consumed from willing sellers the following day. More recently,

**Figure 3.11. EIA annual electricity sales 2000-2016 (terawatts) and AEO reference case electricity sales projections 2017-2030**[m] [42]

Bold up actual usage line and projections and axis numbers, cut off at 2025




Currently, about 90 percent of U.S. residential electricity, 60 percent of commercial, and 30 percent of industrial electricity consumption is used in appliances and equipment that are subject to Federal minimum efficiency standards implemented—and periodically updated by—the Department of Energy (DOE). Between 2009 and 2030, these cost-effective standards are projected to save consumers more than $545 billion in utility costs, reduce energy consumption by 40.8 quadrillion British thermal units, and reduce carbon dioxide ($CO_2$) emissions by over 2.26 billion metric tons.

There are two significant impacts of the growth in energy efficiency. First, the unexpected flattening of energy and peak demand has changed suppliers' expectations and behavior relative to reasonable expectations when competitive energy markets began. In the 2000 to 2005 timeframe, investors and

merchant developer Panda Energy has filed suit against ERCOT (the Texas grid operator), claiming that ERCOT's consistently high demand forecasts fraudulently overstated the region's future electric requirements, predicting resource scarcity that never materialized. Panda claims that it built a 785 MW, $2.2 billion gas plant on the basis of those "false and misleading" forecasts (as did other merchant developers) and when the high demands never materialized, ERCOT had overcapacity that drove down electricity prices and drove the Panda plant into bankruptcy only X years after it went on-line. See, for instance, "PE Firm Puts Plant Into Ch. 11, Blames Texas Grid Regulator," Law 360, Keith Goldberg, Law360, April 18, 2017, and "Power company sues grid operator over demand, supply projections," Jordan Blum, Houston Chronicle, March 26, 2016.

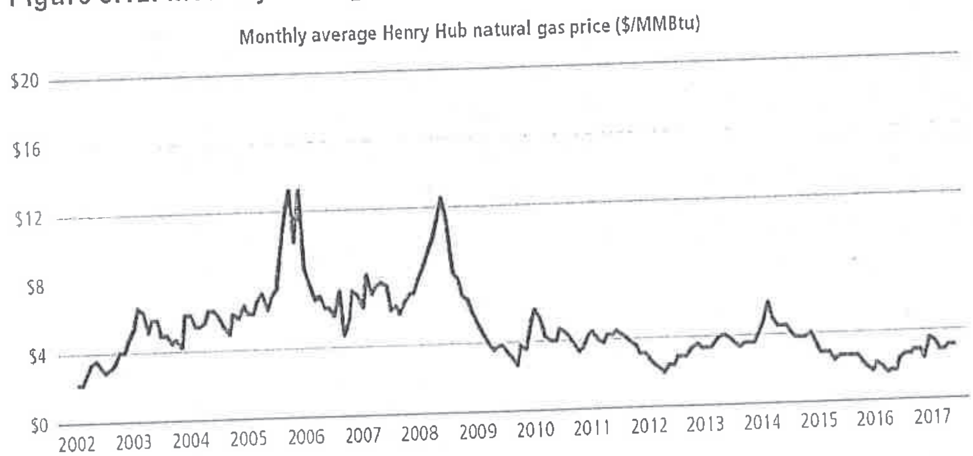
[m] This figure demonstrates how changes in economic, market, and technological trends and in policies affecting energy use in the U.S. can affect total electricity sales. The AEO Reference Case is a business-as-usual trend estimate that assumes that laws and regulations in effect at the time are 'frozen' and continue throughout the timeframe of the projection. Its goal is to project what might happen in the future if no new policies are enacted—it does not attempt to forecast what will happen. Federal and state policies, market forces, and broader economic factors have had the net effect of lowering electricity consumption compared to what was expected to occur in absence of any change, as shown by the comparison of historical AEO Reference Case projections to actual U.S. electricity sales.

plant operators would have reasonably expected that growing customer demand for electricity would have assured that new generation capacity could be sold profitably.

## 3.4 Cause -- falling natural gas prices have reduced wholesale electricity prices

Unconventional natural gas development, increasing in productivity between 2007 and 2009, has significantly expanded the availability of natural gas and lowered its cost across the U.S. and the world. Before the widespread use of unconventional drilling techniques in the past decade, natural gas prices in the U.S. approached $14/mmBtu in several periods (including in 2005 after Hurricanes Katrina and Rita reduced production and delivery from Gulf of Mexico sources). As fracking practices spread and made previously inaccessible gas sources economic, natural gas prices dropped to below one-third of their former levels (See Figure 3.12).

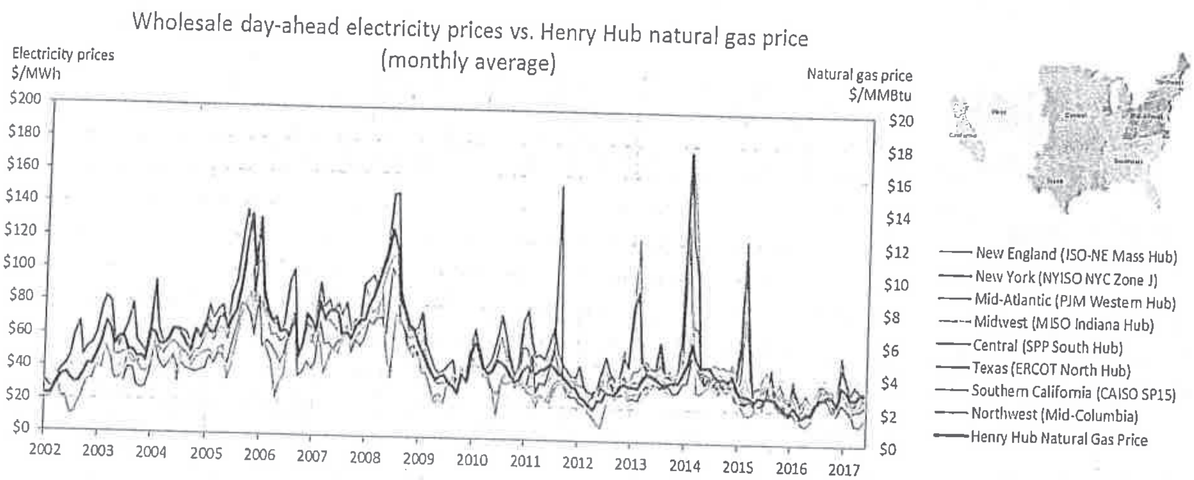
**Figure 3.12: Monthly average Henry Hub natural gas price ($/mmBtu)[43]**




Although coal and nuclear generation produced more energy per year than gas-fired generation, electricity prices have tracked natural gas prices for more than 15 years, as shown in Figure 3.13. This is because gas-fired mid-merit and peaker power plants have been the marginal generators following load in many hours of the day (as discussed in Section --), and their short-run marginal costs are driven by natural gas prices. Thus natural gas plants and gas prices have driven spot market electricity prices. Since spot market prices are used as a marker for setting prices for bilateral electric contracts, natural gas prices also drive the price for most of the wholesale electricity sold across the nation.[n]

[n] Although wholesale prices closely follow natural gas prices and are now at historically low levels, retail electric prices remain relatively flat and have not sunk as low as wholesale prices. This occurs for several reasons, including the need for retail rates to collect the utility's capital, operating and administrative costs for transmission and distribution, retail sales, and many other programs. Utility retail rates in vertically integrated states include return of and on capital investments in utility-owned power plants (which is not a protection available to merchant generation) and the costs of the total energy acquisition portfolio. State legislators and regulators also impose a variety of program requirements that may raise retail electricity costs.

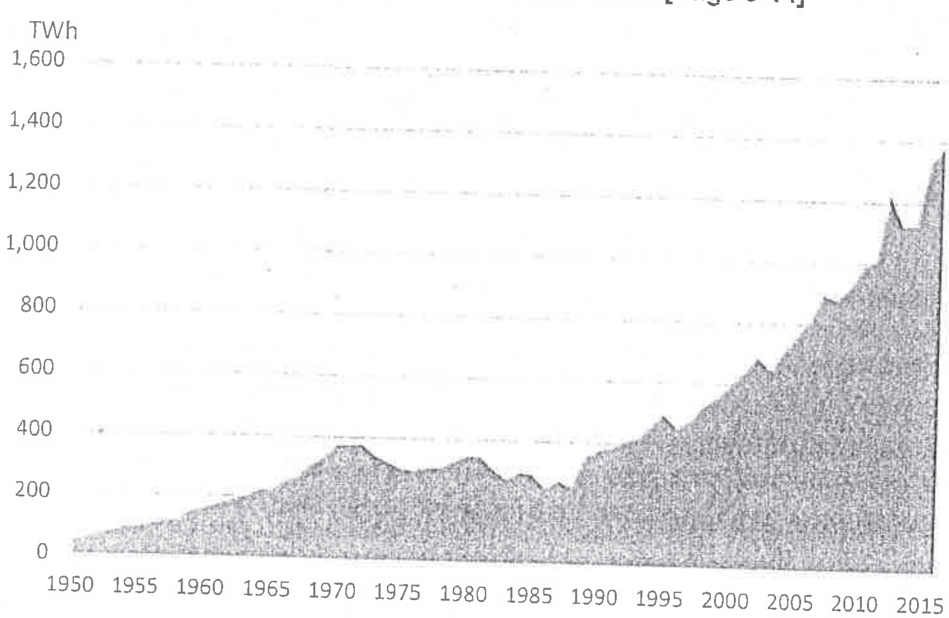
**Figure 3.13. Wholesale day-ahead electricity prices vs. Henry Hub natural gas price (monthly average)[44]**




Although natural gas is being blamed as the cause for major havoc within the power sector, the nation has realized extraordinary economic benefit from the fracking revolution. Since gas prices starting falling in 2009, the increased supply and lowered cost of natural gas has delivered effective benefits of $ trillions to the American economy...

Natural gas–fired generation has grown nearly continuously since the late 1980s. These plants have low capital costs and gas pipelines can be built more quickly than electric transmission lines, so it was often easier for a plant developer to build a new gas-fired plant near a large electric load than to build a higher-cost coal plant farther away and ship the coal by wire to large load centers.

**Figure 3.14. U.S. Natural Gas Generation, 1950-2016. [Page 3-14]**




NGCC generators are very efficient, have unused capacity, and have significantly higher capacity factors than natural gas combustion turbines (CTs), which contribute primarily to peak load and may only operate for a few hours a year. Until recently, most NGCC units were utilized for intermediate and peak loads, rather than baseload. Because natural gas prices have been low for a sustained period, and because NGCC plants retain some of the flexible characteristics of CTs and operate at a higher efficiency and lower cost, these units are now often used for baseload power.

A CT's short start-up times and fast ramp rates makes it essential for maintaining grid reliability, absent affordable grid-scale storage, given today's resource mix. Capacity factors for CTs are quite low (generally below 10 percent), but when operating, they can be significant contributors to conventional air pollutants.[45] Single-cycle natural gas turbines can go from cold start-up to 100 percent output in 7–11 minutes; in contrast, coal-fired units ramp on the order of hours, and doing so incurs increased operations and maintenance costs.[46] NGCC ramp rates fall somewhere in between, and some NGCC units can ramp to full rated power in less than 30 minutes.[47] This flexibility makes CTs useful in complementing variable generation, especially for solar, because this flexibility complements the high peaks associated with solar generation and allows for load following. Some states rely on CTs more regularly than other locations; most notably, Texas, Louisiana, Wyoming, New Hampshire, Maine, and Rhode Island all have CT capacity factors greater than 20 percent.[48]

## 3.5 Cause – subsidies

A subsidy is a transfer payment of funds from one group of people to another – federal or state taxpayers to nuclear plant owners, a utility's electric ratepayers to its energy efficiency users, federal taxpayers to renewable energy producers, and so on – to lower the effective cost of the benefiting technology or fuel source. Subsidies are created to perform different functions and serve varying public policy goals, including developing technology, advancing reliability, supporting an infant industry, creating or preserving local jobs, creating competitive international business advantage, or reducing power system pollution and emissions. All subsidies distort markets, but each affects different markets in different ways.

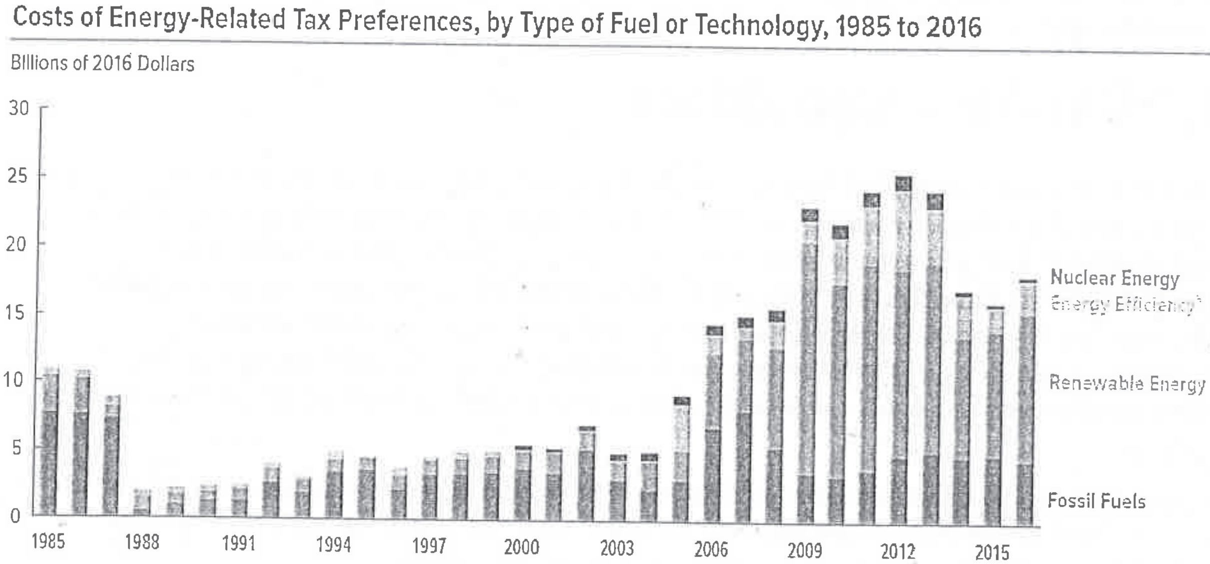
Every form of energy and energy source present in modern electricity and energy service provision is subsidized or incented in one form or another, and most have been subsidized for many decades. The forms of subsidies and incentives in place today for energy resources include:

- Tax policy (accelerated depreciation, depletion allowances, production tax credits, investment tax credits, etc.),
- Regulatory requirements (safety and environmental requirements, renewable portfolio standards, ethanol use requirements, procurement mandates, efficiency standards),
- R&D funding (research, development and demonstration), market purchases (particularly for federally-owned hydropower and transmission systems),
- Government services (information and marketing, technology transfer, federal land and resource leases, provision of highways, ports and waterways) (the Congressional Budget Office estimates annual lost revenues due to low royalty rates for on-shore and off-shore oil, gas & coal resources at $2 billion/year.
- Disbursements (direct grants and subsidies, as for oil tankers, nuclear insurance guarantees, or ARRA grants)[49]
- Not charging for externalities such as pollution or increased need for grid integration services.

The MIS study, prepared for the Nuclear Energy Institute, [MIS 2016] shows over the past two decades the largest energy subsidy beneficiaries have been coal and renewables and that tax incentives have been the means for the largest subsidies. MIS estimates that, "the federal government's primary support for nuclear energy development has been in the form of research and development (R&D) programs, one of the more visible types of incentives identified. For the last 20 years, federal spending on R&D for coal and for renewables has exceeded spending on nuclear energy R&D. Over the past six years, 2011 through 2016, renewable energy received more than three times as much help in federal incentives as oil, natural gas, coal, and nuclear combined, and 27 times as much as nuclear energy."

The Congressional Budget Office has estimated the costs of energy-related tax preferences – a limited set of subsidies for a more limited period of time – over the period 1985 through 2016. As noted above, tax preferences include depletion allowances (oil and gas, geothermal), investment tax preferences (solar PV) and production tax credits (wind).

**Figure 3.15: Costs of Energy-Related Tax Preferences, by Type of Fuel or Technology, 1985 to 2016**




Source: Congressional Budget Office, using data from Molly F. Sherlock, *Energy Tax Policy: Historical Perspectives on and Current Status of Energy Tax Expenditures*, Report for Congress R41227 (Congressional Research Service, May 2, 2011), p. 26, and updated data from the Congressional Research Service; Joint Committee on Taxation, *Estimates of Federal Tax Expenditures for Fiscal Years 2016–2020*, JCX-3-17 (January 30, 2017), pp. 29–30, http://go.usa.gov/xXBA6; staff of the Joint Committee on Taxation, "Estimated Budget Effects of Division Q of Amendment #2 to the Senate Amendment to H.R. 2029 (Rules Committee Print 114-40), The 'Protecting Americans From Tax Hikes Act of 2015,'" JCX-143-15 (December 16, 2015), http://go.usa.gov/xXKNZ; Department of the Treasury, *Combined Statement of Receipts, Outlays, and Balances* (December 2016), http://go.usa.gov/xXKN9; and Office of Management and Budget, *Budget of the U.S. Government, Fiscal Year 2017: Appendix* (February 2016), p. 1025, http://go.usa.gov/xXKNR.

Several states have established or are considering creation of subsidies such as New York's Zero Emissions Credit to flow additional funds to nuclear power plants that are no longer cost-competitive.[o]

Subsidies, in the form of federal R&D and federal tax credits, encouraged the development and spread of wind and solar generation -- just as, in earlier decades, federal R&D and subsidies enabled the development and commercialization of civilian nuclear energy and the natural gas combustion turbine and the realization of hydraulic fracking techniques for oil and gas development. Clearly all of those subsidies contributed to the current baseload problem, but no one can be blamed for it.

[o] The current bill before the New York Legislature to enact the Zero Emissions Credit provision would fund the credit using monies collected from New York taxpayers for the operation of the NY Energy Research & Demonstration Agency. If enacted in its current form, this bill would essentially pay for the subsidies required to keep New York's nuclear power plants in operation, producing zero-carbon electricity, by supplementing electricity customers' energy and capacity payments with taxpayer funds.

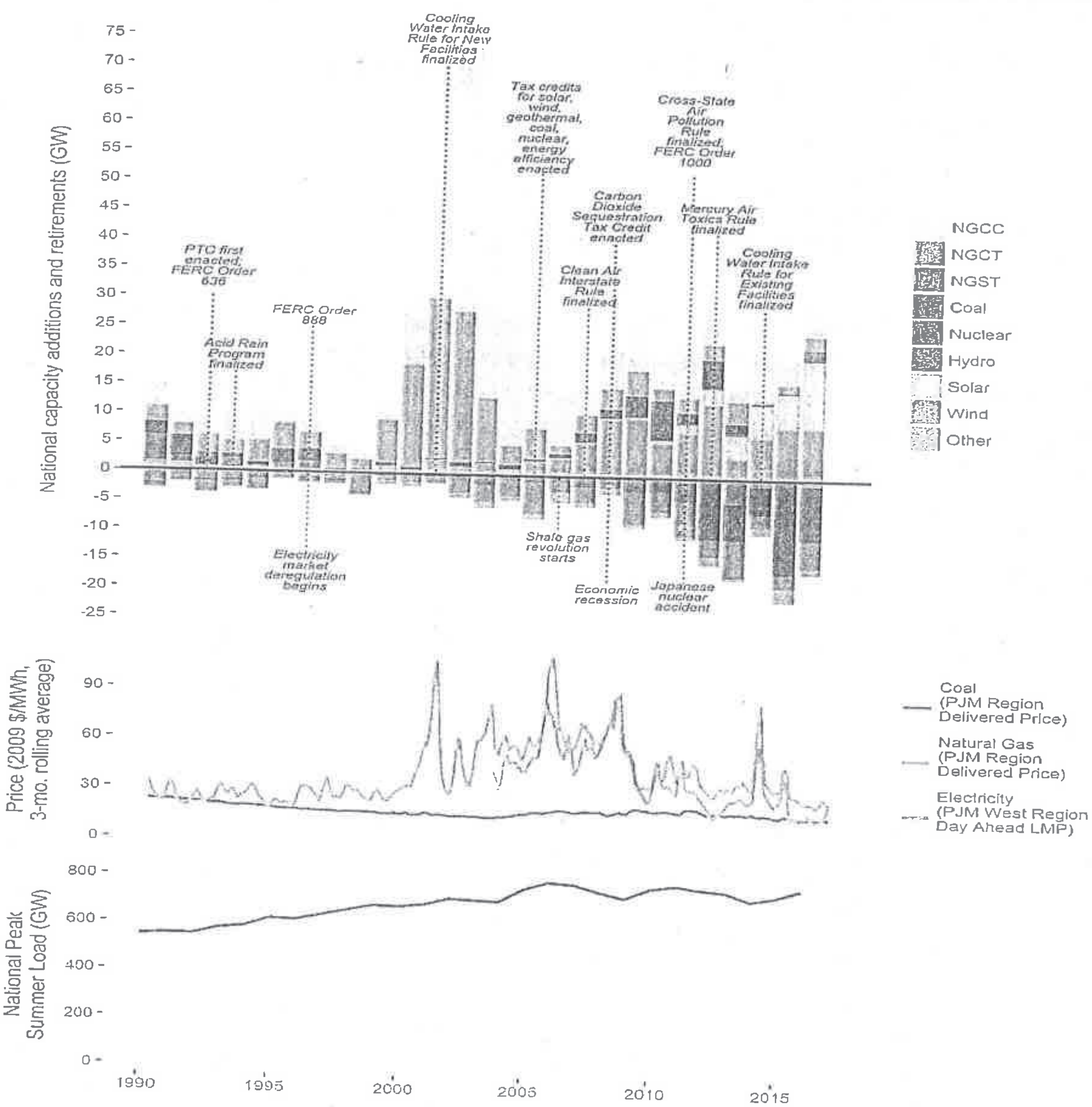
If the goal is to eliminate subsidies to avoid picking winners and losers, or to avoid favoring one fuel or technology over another across electricity markets, the only way to do that would be to attempt to eradicate all forms of subsidies for all forms of electricity sources (including wind and solar ITC and PTC, low-cost coal leases, oil and gas depreciation allowances, nuclear loan guarantees, all energy R&D expenditures, all ethanol purchase requirements, energy efficiency funding, and so on). Since most of these subsidies were created by statute and have deep political support, thorough and universal repeal of all energy-related subsidies would be difficult.

## 3.6 Cause – regulations

Figure 3.16 shows electric capacity additions and retirements between 2002 and 2017, along with key regulations affecting electric generation, the price curves for natural gas and coal, and customer demand levels over that period. The graphs show a strong correlation between falling natural as prices and baseload retirements as well as flattening electric demand and retirements. It also shows many coal plants retiring in 2015 to avoid having to make new capital investments for environmental remediation in a time of low electricity prices.

**Figure 3.16. Big picture of retirements and contributing factors**[p] [50]

[narrow price graph legend to make narrower so we can make charts wider; pop hairlines more]




Timeline of Electric Generating Capacity Additions and Retirements, Tax Incentives, Orders and Regulations, Regional Market Prices, and Load

cost estimates for regulatory impact – check EIA, EEI, NEI, EPSA, NERC, trade press, EPA, utility 10ks and presentations – correlate to timing of impact and deadlines and inability of these

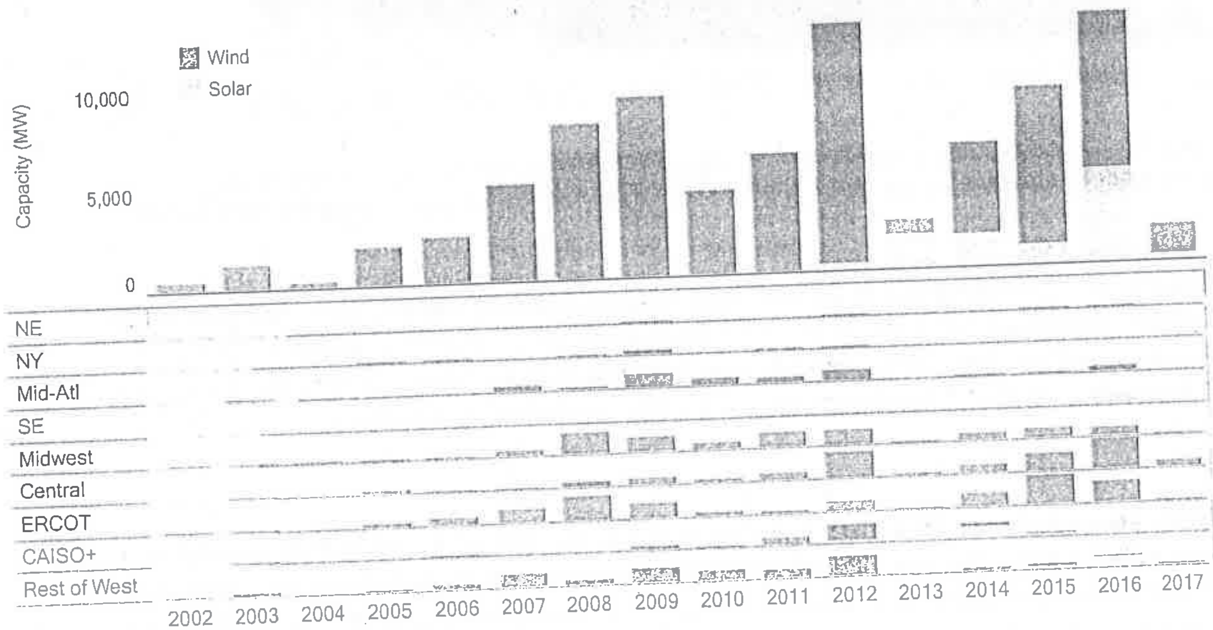
[p] Wholesale day-ahead electricity market prices are for the PJM West Region. Delivered coal and natural prices are aggregated monthly PJM regional fuel costs derived from FERC-423 and EIA 923 data files. In addition to the 7 states in PJM, EIA included power plant fuel costs for Commonwealth Edison, East Kentucky Power Cooperative, Dominion Power in North Carolina, and Indiana-Michigan Power. EIA weighted the fuel receipts by total quantity of fuel delivered to calculate a weighted average monthly cost. We converted the fuel prices from MMBtu to MWh to account for different efficiencies of power plants using an average heat rate of 10000 Btu/kWh for coal and 7200 Btu/kWh for natural gas.

plants to recover short-term operating costs much less capital cost recovery w/o additional environmental capital charges

## 3.7 Cause – renewables

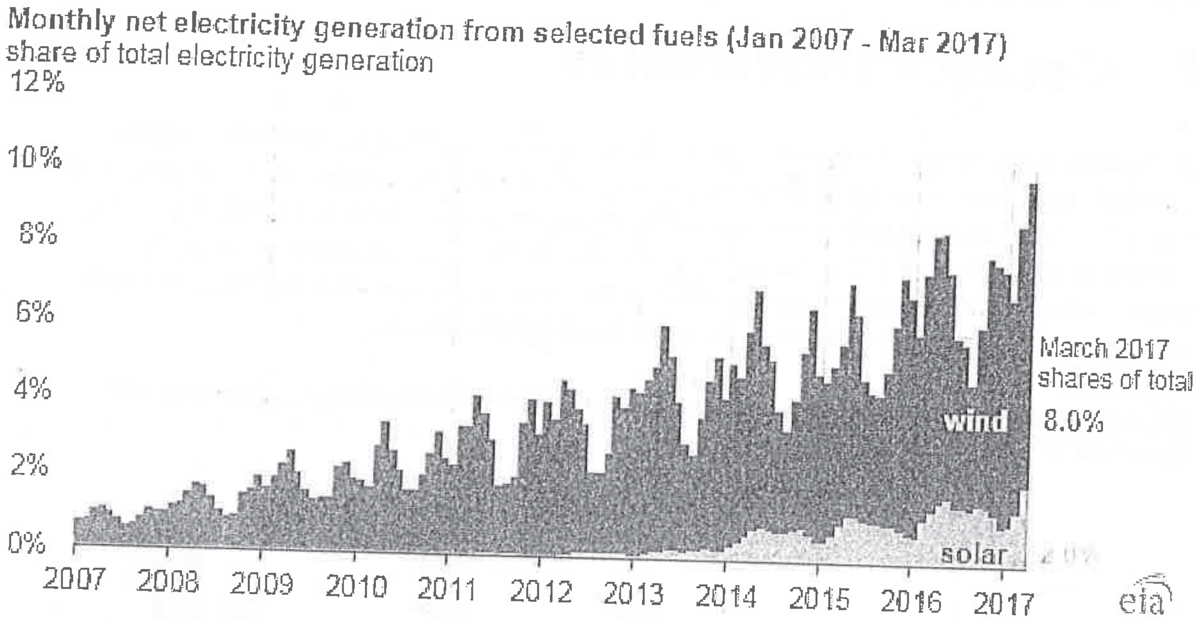
Figure 3.17 shows the annual installations of wind and solar generation across the nation from 2002 through 2017 (to date). Figure 3.x shows the growth in monthly net electricity generated from wind and solar sources since 2007. These graphs show that there was relatively little wind installed before 2007, and minimal solar capacity before 2013. Since over – GW of coal and __ of natural gas generating capacity retired between 2002 and 2007, and another – MW retired between 2008 and 2012, renewable generation could not have been the sole cause for these baseload retirements.

**Figure 3.17. Annual Generation Capacity of Wind and Solar, Total and by Region, January 2002 through March 2017[q]**




[q] Energy Information Administration (EIA), "Monthly Update to Annual Electric Generator Report," March 2017, https://www.eia.gov/electricity/data/eia860m/

**Figure 3.18. Monthly growth in net wind and solar energy**




(Source: EIA, "Today in Energy, Wind and solar in March accounted for 10% of U.S. electricity generation for the first time," June 14, 2017; note that EOA did not collect small- scale PV data before 2012)

Wind and solar generation combined reach their highest levels in spring and fall, when customer energy demand is lower. This exacerbates the problem for baseload plants, in that since customer loads are already lower in spring and fall, having renewable energy peak in those seasons further erodes the size of the customer low load slice willing to buy coal, nuclear or natural gas-fired power.

Wind

Wind turbines have contributed more than one-third of the nearly 200 GW of 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 production tax credits and grants. More than half of U.S. wind capacity is located in five states: Texas, Iowa, Oklahoma, California and Kansas. (Figure x) In particularly windy hours, wind output has contributed as much as 50% of the electricity generation mix. [add cites for SPP, ERCOT]

**Figure 3.19. Wind generation growing[51]**

**Distribution of wind power plants in the Lower 48 states (as of December 2016)**

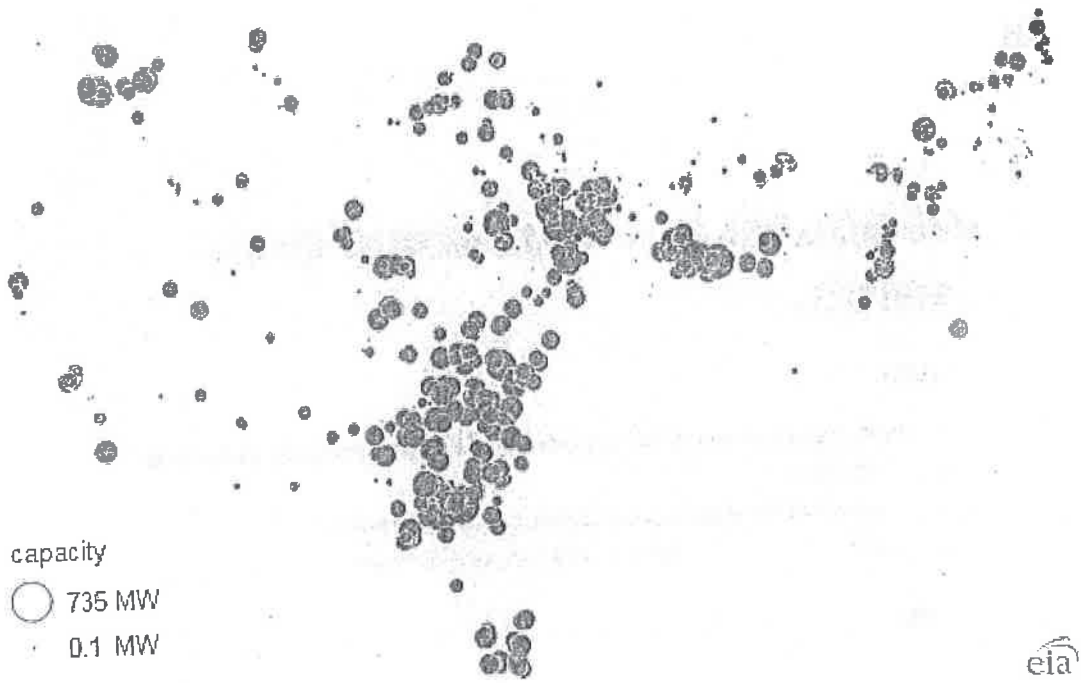
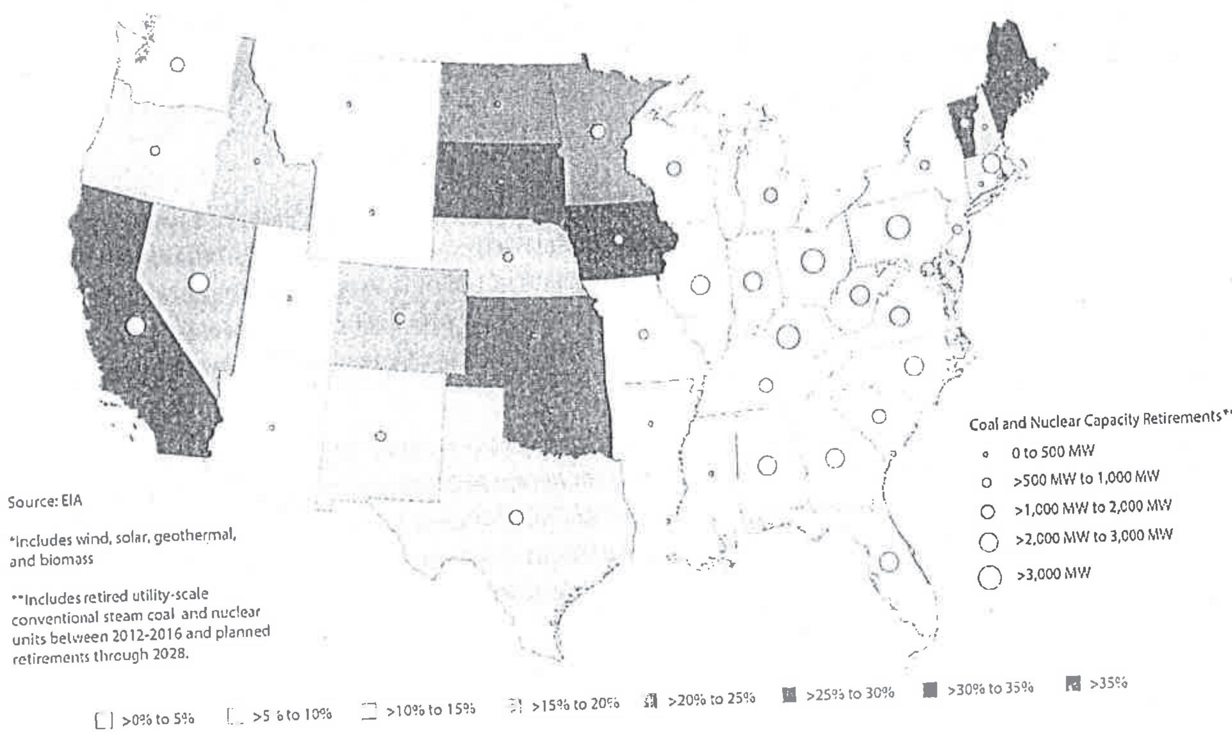



**Figure 3.20. Renewable penetration not correlated with coal and nuclear plant retirements[52]**

Recent and Planned Coal and Nuclear Retirements
and 2016 U.S. Renewable Energy* Share of Electricity Generation, by State



DUCK CURVE – explain impact. This a regional impact that needs to be managed on a regional basis (see next chapter on reliability)

GREATER NEED for cycling and ramping

## 3.8 Consequence -- nuclear plant retirements

A recent report observes that:

- There is an industrywide systemic economic and financial challenge to operating nuclear power plants in deregulated markets;
- Given the confluence of market factors in combination with market structure in deregulated 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 5 years;
- Early retirement of nuclear plants is primarily caused by lower revenue problem[r] rather than 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 to 15 per MWh. For a 1,000 MW nuclear unit, approximately every $5 per MW 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 face premature retirements in the future.[53]

<u>Overview of the U.S. nuclear fleet</u>

FROM QER: The current operating nuclear power fleet consists of approximately 54 GW of generating capacity in regulated markets and 45 GW in restructured electricity markets.[54] In total, this represents 9% of total U.S. 2017 utility-scale generation capacity, producing 20% of U.S. electric production in 2016. EIA reports that nuclear plants have higher capacity factors than any other electric generation technology, averaging 90% (nearly full capacity full-time) over the past five years. The plants refuel every 18 to 24 months.[55]

The first of these units went on-line in 1969; the average age of the nuclear fleet is 37 years old (capacity-weighted).[56] 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 GW of additional nuclear capacity.[57] In addition to capital investments for capacity uprates, nuclear owners make significant plant component investments to replace aging components to qualify for license

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[r] The report, "Economic and Market Challenges Facing the U.S. Nuclear Commercial Fleet," from the 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"

renewal, plus a suite of new safety investments to comply with new regulations following the Fukushima reactor problem in 2011.

The United States has the world's largest nuclear reactor fleet. These plants deliver grid stability and reliability, price stability, fuel security, and provide reliable and resilient power, especially during extreme weather events such as the 2014 Polar Vortex. Nuclear power plants contribute about 20% of the nation's electricity and about 60% of total U.S. emissions-free generation. The 99 active nuclear reactors (located in 61 power plants) provide almost half a million jobs and contribute over $60 billion to the U.S. gross domestic product.[58]

Many view nuclear energy as a key strategic asset for the United States. They argue that nuclear power is an essential strategic asset and that the nation has a strategic imperative to maintain and enhance American leadership and influence in global nuclear markets, including in the export of commercial nuclear technologies and systems.

Of these 99 units, 53 are owned by traditional utilities (private and publicly-owned) which rely on regulated cost-of-service ratemaking. This form of ratemaking provides a reliable source of cost recovery assuming reasonably prudent operation and management by the utility. These units' continued operation depends on decisions by their ratemaking authorities: state regulators, state governments, city councils, and cooperative boards state regulatory bodies, plus two federal agencies, the Tennessee Valley Authority (which operates 7 nuclear units) and the Bonneville Power Administration (which operates 1 unit). Authorities may decide to close nuclear units on grounds other than economics or even system reliability – for example, New York State seeks to close the Indian Point plant due to its proximity to the New York City metropolitan area.

Twenty-eight nuclear units are merchant plants that were spun off to affiliates by vertically integrated utilities under state competitive restructuring efforts in the early 2000s. All these merchant nuclear units operate in ISO/RTO systems. Many of the units went merchant to exploit high locational marginal prices (LMPs) in ISO/RTO energy markets in the days of high natural gas prices; profits from high LMP prices are not available to utility cost-of-service regulated units because their revenues are set by state regulators to recover of operating costs and provide a target return on invested capital. Most of the merchant plant conversions involved spinning the merchant plant off as an affiliate of the original vertically integrated utility owner, with a power purchase agreement between the affiliated merchant and the regulated utility specifying pricing provisions and durations. Once the initial power purchase agreement expires, the merchant plant must compete with other generators for contracts or spot sales in the organized power markets. The Kewaunee nuclear plant in MISO (WI) retired in 2013 after its purchase power agreement expired and the owners were unable to find a new purchaser for the power or the unit due to expectations of continued low natural gas prices and electric prices.

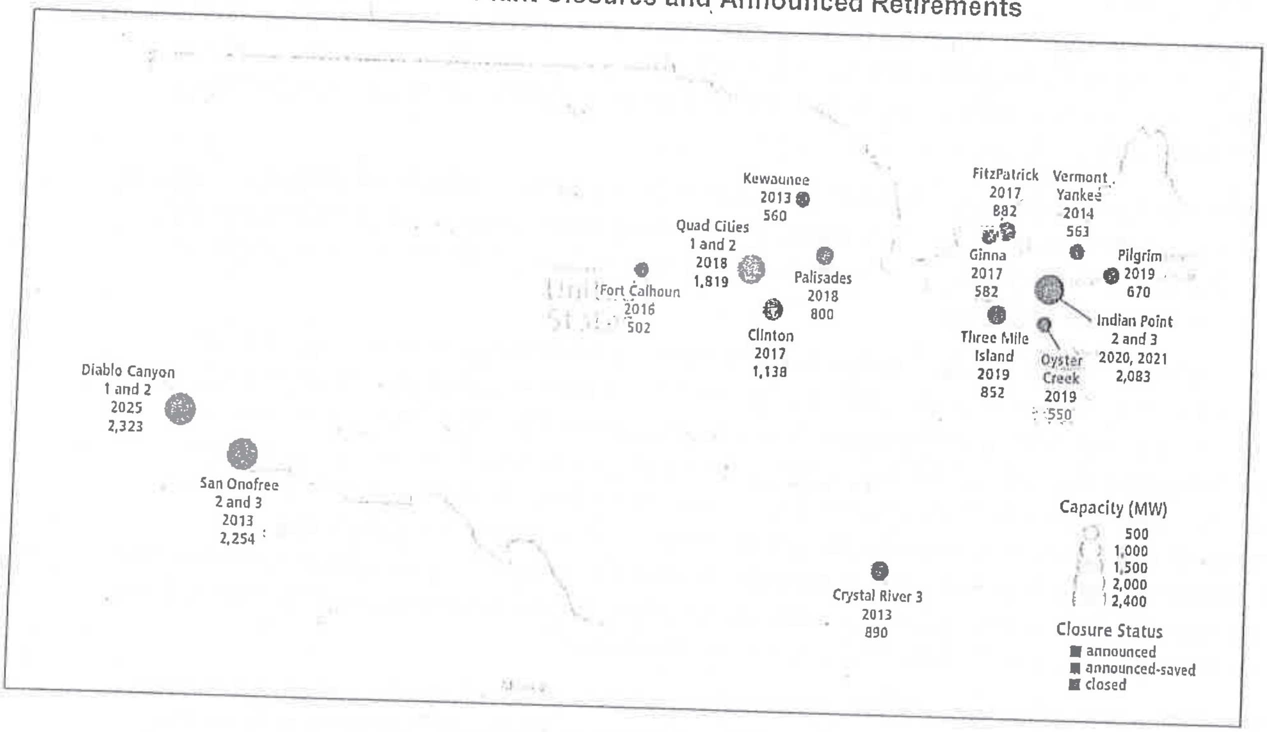
Twenty nuclear units were spun off to entities other than affiliates of the original vertically integrated utility. Many of the independent nuclear owners are affiliates of vertically integrated utility holding companies (Exelon, Entergy, NextEra, Dominion). Exelon Nuclear and Exelon Generating Co. own 29 (half) of all 48 merchant nuclear units.

<u>Nuclear plant retirements</u>

Nuclear plant retirements are a recent phenomenon, with the first post-Three Mile Island retirement announcement occurring in 2012. Figure 3.21 shows the nuclear reactors that have announced retirements (including those whose closure has been averted by state action). To date, 4,666 MW of nuclear plant capacity has retired – 5% of the U.S. nuclear capacity and less than one percent of total U.S. generating capacity. As noted above, another – plants representing – MW of nuclear capacity (--%

of the U.S. nuclear capacity and --% of total U.S. generating capacity) has announced retirement plans (not counting the five plants that changed their plans after their host states offered subsidy payments for each plant to remain open).

**Figure 3.21: Map of Nuclear Power Plant Closures and Announced Retirements**




## Reasons for nuclear plant retirements

Table 1 lists the nuclear plants that have announced retirement, illustrating the range of operating costs for these plants.

**Table 3.1: Nuclear plant retirements and announced closures**[59] [60] [61]

| Reactor | Retired/ Announced Closure Year | Relicense Application Received[i] | Relicense Granted?[ii] | Entered Extended operation[iii] | State | Average Operating Cost (year)[iv] | Capacity Factor 2014-2016[v] | Reason for Closure |
|---|---|---|---|---|---|---|---|---|
| Crystal River 3 | 2013 | 12/18/08 | Withdrawn 2/6/13 | -- | FL | 40.25 (2012 fleet avg) | -- | failed steam generator replacement |
| Kewaunee | 2013 | 8/14/08 | 2/24/11 | -- | WI | 40.25 (2012 fleet avg) | -- | market conditions |
| San Onofre 2 and 3 | 2013 | -- | -- | -- | CA | 40.25 (2012 fleet avg) | -- | failed steam generator replacement |
| Vermont Yankee | 2014 | 1/27/06 | 3/21/11 | 3/21/12 | VT | 36.81 (2014 fleet avg) | 89.8 (2013-2014)[1] | market conditions |
| Fort Calhoun | 2016 | 1/11/02 | 11/4/03 | 8/9/13 | NE | 36.13 (2015 fleet avg) | 61.8 (2013-2015)a | market conditions |
| Fitzpatrick[2] | 2017 | 7/1/06 | 9/8/08 | 10/17/14 | NY | 40.97 (2016, single) | 85.8 | market conditions |
| Clinton[b] | 2017 | Notice of intent to apply in 2021 | -- | -- | IL | 40.97 (2016, single) | 95.1 | market conditions |
| Ginna[b] | 2017 | 8/1/02 | 5/19/04 | 9/18/09 | NY | 40.97 (2016, single) | 95 | market conditions |
| Quad Cities 1 and 2[b] | 2018 | 3/3/03 | 10/28/04 | 12/14/12 | IL | 31.85 (2016, double) | 99.6, 95.2 | market conditions |
| Palisades | 2018 | 3/31/05 | 1/17/07 | 9/8/10 | MI | 40.97 (2016, single) | 93.2 | market conditions (despite being under PPA through 2022) |
| Pilgrim | 2019 | 1/27/06 | 5/29/12 | 6/8/12 | MA | 2015? | 90.5 | market conditions |
| Oyster Creek | 2019 | 7/22/05 | 4/8/09 | 4/9/09 | NJ | 40.97 (2016, single) | 91.5 | avoid large capital costs associated with building a cooling tower |
| Three Mile Island 1 | 2019 | 1/8/08 | 10/22/09 | 4/19/14 | PA | 40.97 (2016, single) | 99.4 | market conditions |
| Indian Point 2 and 3 | 2020, 2021 | 4/30/07 | -- | -- | NY | 31.85 (2016, double) | 86.3, 93.8 | state policy disputes |
| Diablo Canyon 1 and 2 | 2024/2025 | 11/24/09 | -- | -- | CA | 31.85 (2016, double) | 92.4, 92.2 | market conditions and state policy concerns |

Two plants (three reactors) have closed in the face of costly repair requirements.

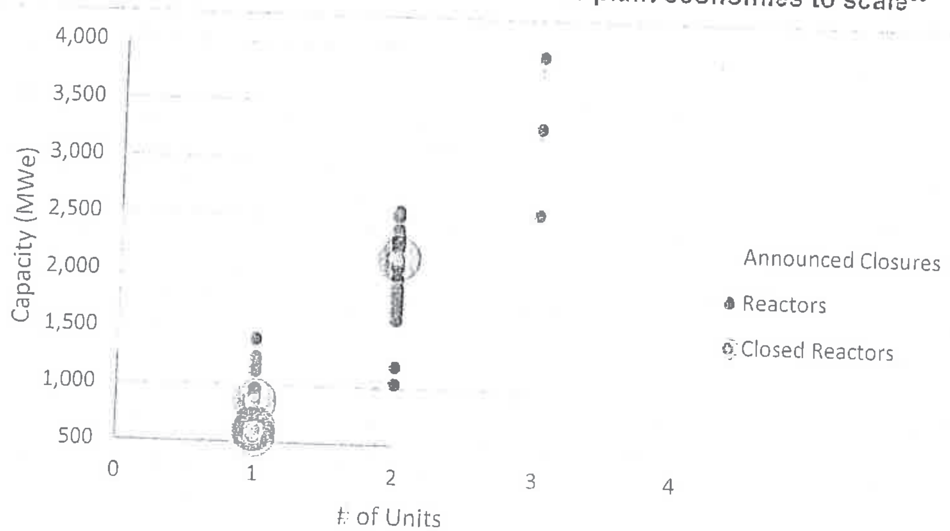
- Problems with a steam generator replacement project led to the permanent shutdown of Southern California Edison's San Onofre Nuclear plant (SONGS) units 1 and 2 in 2012. After replacing the steam generators at both units, one of the new steam generators experienced internal leakage about a year later; inspections showed vibration-related damage to all the new steam generators, later attributed by SCE to design flaws.[62] After considering repair and replacement options, SCE announced in June 2013 that it would retire San Onofre 2 and 3. The company cited uncertainty about whether and when the units would be allowed to restart at lower power by NRC, pending steam generator replacement or repair, as a major factor in the shutdown decision. Other considerations were the projected price of replacement power while repairs were being implemented and uncertainty about renewal of the two reactors' operating licenses in 2022, according to SCE.[63]
- At Progress Energy's Crystal River nuclear plant (subsequently part of the Duke Energy acquisition of Progress), which went on-line in 1976, the plant's concrete containment structure was damaged in 2012 during an effort to replace the plant's steam generators. Facing a potential repair bill from $1.5 to 3.4 billion,[64] Duke Energy announced in 2013 that, "it decided to close the plant because of unacceptable uncertainty about the scope, cost, and duration of repairing or replacing the damaged containment structure."[23]

Five of the six nuclear reactors that have shut down since 2012 were small single unit plants. Of the 11 nuclear power plants (15 reactors) that have announced intentions to close, four are dual-unit plants and seven are single-unit plants, as illustrated in Figure 3.22. This graph indicates that the bulk of nuclear plants heading for retirement are (were) smaller and/or single-unit plants with higher production costs per MWh. Table 3.2 confirms that nuclear economies to scale are significant -- smaller units have notably higher costs than larger units, and higher costs than multi-unit plants.

<u>Nuclear plant costs and revenues</u>

There are clear patterns in nuclear reactor operating costs – specifically, because these plants have such large capital and operating costs, economies to scale have a great impact on plant economics. Figure 3.22 illustrates where the retiring nuclear plants stand with respect to reactor size and the number of units.

**Figure 3.22. Retiring nuclear plants and nuclear plant economies to scale[65]**



Announced nuclear plant closures arrayed by number of reactors (units) and plant size (including the six New York and Illinois units that are no longer expected to retire due to state decisions to subsidize plant operation.

Table 3.2 shows the range of nuclear plant average costs in 2016, in $/MWh. The table indicates that single unit plants are more costly than multi-unit plants, and that operators that own only one nuclear plant have higher costs than those which own a fleet of plants. Because some operating costs, such as security, do not scale linearly with plant size, single-unit plants are more expensive to operate and as a result they are more likely to be retired before the end of their license terms.

**Table 3.2 Average nuclear costs by reactor type, 2016**[66]

## 2016 Cost Summary ($/MWh)

| Category | Number of Plants / Sites | Fuel | Capital | Operating | Total Operating (Fuel + Operating) | Total Generating (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*
*Source: Electric Utility Cost Group (EUCG)*

As shown in the nuclear plant closure table above, eleven of the 15 plant closure announcements refer to "unfavorable market conditions" as the driver for plant retirement. The most unfavorable condition is that the marginal cost of generation for many nuclear plants is higher than the cost of most other generators in the market:[67]

- Wind marginal cost — near $0/MWh, mostly at night
- Solar marginal cost — $0/MWh, daytime
- Natural gas CC marginal cost at 7,000 Btu/kWh — $25/MWh ($3.00/MMBtu for fuel)
- Coal marginal cost at 10,000 Btu/kWh — $29/MWh ($2.50 MMBtu for fuel)
- Nuclear marginal cost — $27 to 32/MWh
- Natural gas CT marginal cost at 10,000 Btu/kWh — $49/MWh ($3.00 MMBtu for fuel)

Since U.S. nuclear generators are run flat out without cycling or ramping, they need to produce around the clock; in combination with low-priced wind, solar and coal generation and natural gas steam plants in night-time minimum load hours (and increasingly, some peak daytime hours in areas with high PV penetration and transmission constraints), the over-supply of generation from all sources drives down market-clearing energy prices and energy revenues for all producers.

A nuclear plant fully exposed to wholesale market competition can earn additional revenues in three other ways – it may receive capacity payments if it is located in an organized market with a capacity payment scheme (New York, New England and PJM), it can earn revenues for providing reliability products such as frequency response, or it may receive Zero Energy Credits or similar subsidy payments from its host state. But those revenues may not be enough to cover the plant's full costs, including capital recovery. A recent study of the three Illinois nuclear plants estimated that the Quad Cities plant lost between $150 and $300 million each year between 2011 and 2016, the Byron plant lost between $70 and 240 million per year in four of those five years, and the Clinton plant lost between $52 and 98 million in each of the five years. If a nuclear plant is owned by a vertically integrated electric utility, 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. But as long as natural gas prices stay down and there is an over-supply of energy in many hours of the day and year, the typical nuclear plant will lose money on every kWh produced, and not be able to make it up on volume. Bloomberg New Energy Finance estimates that 34 of the nation's 61 nuclear plants are out of the money, including many of Exelon's merchant nuclear units.[68]

Not all nuclear power plants close due to unfavorable economics alone. The Diablo Canyon two-unit plant in California is an example of a plant that is closing because changes in state policy (specifically, moving to a 50% RPS by 2040) will render the plant wholly uneconomic if it invests in replacement of its once-through cooling system, at a cost of $8 to 12 billion, to satisfy environmental regulations. This led the plant's owner to negotiate closure terms with the state to assure a smooth transition, rather than closing abruptly.

## Reasons behind Diablo Canyon nuclear shutdown

**Source: David R. Baker, San Francisco Chronicle, "Diablo Canyon closure shows California's power grid is changing fast," July 2, 2016**

Pacific Gas and Electric Co.'s surprise decision to shut down Diablo Canyon, the last nuclear plant in California, came after the company squinted at the future and realized that the massive facility would be an awkward fit.

When Diablo opened in 1985, big plants produced large amounts of electricity and fed it to a grid where power basically flowed one way, from generator to customer. Think of water pouring through a network of pipes to numerous taps: Utilities controlled the whole flow, from source to sink.

Now, many businesses and homeowners produce their own energy. A solar array is installed in PG&E's territory every six minutes. Many generate more electricity than they need during the day, feeding the excess back onto the grid.

Huge amounts of solar power flood the grid at midday, falling off sharply in late afternoon. Wind power surges at night. Power flows fluctuate with the weather.

And a fast-growing number of cities and counties — including San Francisco, PG&E's hometown — are buying electricity on behalf of their citizens through a system called community choice aggregation, partially bypassing the utilities.

Nuclear plants of Diablo's generation were designed to ramp up to full throttle and stay there day and night, providing "baseload" power for the grid. But that, increasingly, is not what California needs."

"We're transitioning, clearly, to a distributed system where you rely less and less on those big resources and more on distributed resources," said Stephen Berberich, CEO of the California Independent System Operator, which manages the grid.

"You need a flexible fleet that can start and stop quickly," he said. "The way California is headed, big, baseload power isn't as valuable as it was."

The Nuclear Regulatory Commission's nuclear relicensing program is another factor affecting the timing of power plant retirement decisions. The NRC issues initial operating licenses cover a 40-year operating term. Those licenses can be extended for up to two additional 20-year terms. Of the 99 operating nuclear reactors in the United States, so far, 80 have been approved to (and plan to) operate for 60 years, while another 9 currently have applications under review by the Nuclear Regulatory Commission (NRC).[s, 69] The timeline for these units to reach the end of their 60-year license is as follows: 6 units between 2029 and 2030; 27 units between 2031 and 2035; 15 units between 2036 and 2040; 20 units between 2041 and 2045; and 12 units between 2046 and 2050.[70] Forty-eight units will reach the end of their licensed lifetime by 2040. EIA reports that the capital investment required to operate a plant safely past 60 years is currently unknown.[71]

NRC staff estimate that domestic nuclear plant owners decide to pursue a license extension as far as 15 years before the initial license expires; some have applied as early as 22 years ahead (in order to extend two units' licenses in tandem for greater process efficiency). DOE staff estimate that it presently costs a nuclear plant owner approximately $25 million per unit, from application drafting through NRC approval; this includes $4 to 6 million in NRC fees.

Nuclear relicensing often entails major capital upgrades of plant equipment. The two biggest capital investments that have been cited as outweighing continued operation are steam generator replacements and cooling system upgrades. 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 probably requires from $500 million to $1 billion per plant of additional capital expenditures to operate a plant for an additional 20 years.

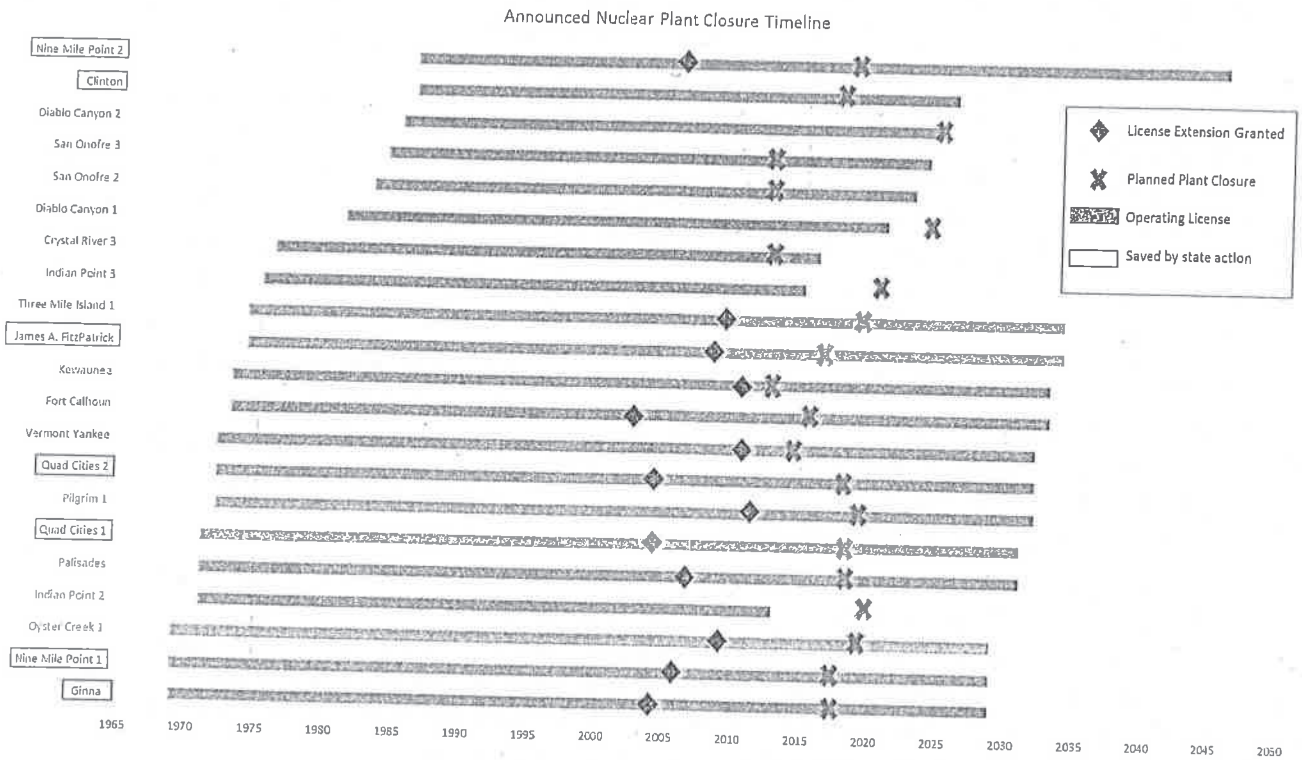
As with other power plants, a nuclear plant owner must assess whether its prospects for future revenues will repay continuing operations costs and capital investments. The fact of an approaching NRC relicensing application deadline forces a nuclear owner to look closely at expected costs – capital costs for equipment replacements and required upgrades,[t] continuing O&M costs, and relicensing costs – and compare those to the likely revenue stream in a market environment that may require less baseload operation and more cycling at low gas-based energy prices. More than one nuclear owner has decided that future revenue prospects don't justify further investments in the plant for long-term plant upgrades and environmental regulatory compliance, and therefore chose to retire the plant in advance of its license expiration. Other plant owners (indicated by the plant name in a box below) were able to avert closure by negotiating with the host state to receive subsidy payments for continuing operation.

**Figure 3.23. Nuclear plant retirements compared to NRC plant operating license terms**[72]

Enlarge and bold up plant names and years

[s] Diablo Canyon 1 and 2 license renewal applications are under NRC review, but Pacific Gas & Electric Company has announced it will withdraw the application.

[t] Some nuclear plants, like Diablo Canyon, are located on oceans and subject to the EPA's Once-through-cooling requirements, which would require costly modifications to the plant's cooling systems. Most nuclear plants have to replace their steam generators after 20 to 30 years of service, at a cost of several hundred million dollars per reactor. For example, replacement of the two steam generators at the Waterford 3 reactor in Louisiana was estimated by the plant's owner at $550 million. (See Entergy Corporation, "Entergy Louisiana Seeks Approval to Replace Waterford 3 Steam Generators," news release, June 27, 2008, http://www.entergy.com/News_Room/newsrelease.aspx?NR_ID=1203) .




## Cooling system updates at Oyster Creek

**Source: Dolley, Steven, "Exelon, New Jersey Agree to Shut Down Oyster Creek by 2019," Nucleonics Week, December 13, 2010**

Exelon's single-unit Oyster Creek plant in New Jersey, the nation's longest-operating power reactor, is ... scheduled to be retired in 2019. When the plant's initial 40-year NRC license was renewed for 20 years in 2009, the State of New Jersey required it to comply with water discharge requirements by building closed-circulation cooling towers to reduce warm water discharges into Barnegat Bay. Exelon said the cooling towers would have cost $700-$800 million and that it would retire the plant if required to build them. Exelon and the New Jersey Department of Environmental Protection reached an agreement in 2010 to close Oyster Creek in 2019, a decade before its license expiration, without building the closed-circulation cooling system.

In these nuclear retirements, each plant owner made the decision to retire the plant because their expectations of future income (based on current and anticipated electric market conditions) from continued operation would not exceed the costs of continuing to operate the plant (including compliance with long-standing operating, safety and environmental regulations).

## Benefits of nuclear power

**(Source: "Utility CEOs to DOE: Hands off state energy policies, grid planning," Gavin Bade, "Utility Dive," June 15, 2017)**

"[There's a] need for a diverse, resilient portfolio in the country and part of that is baseload generation that's being squeezed out of the market right now," said Chris Crane, CEO of Exelon, the nation's largest nuclear operator. "[Nuclear] provides more benefits than just megawatts. The resiliency, fuel diversity — it's important that is factored into price formation."

But Crane said recognizing those benefits could largely be left up to the states. Exelon won financial support for its nuclear plants last year in Illinois and New York, where the generators were under pressure from low natural gas prices, stagnant demand and subsidized renewables. The company is currently pushing for similar subsidies in Pennsylvania, while other utilities seek supports in Ohio, Connecticut and New Jersey.

"Allowing the states to recognize the environmental benefits of nuclear are important at the federal level," Crane said. "All of the incentives for [renewable] generating sources will phase out over time and it will create a more competitive platform. It's just not increasing them at this point."

Subsidies for nuclear plants are being positioned as a payment to assure the retention of the power plant within the host state, to help meet the state's reliability goals (as proposed in Ohio), protect local jobs, or retain zero-emissions generation to support attainment of the state's greenhouse gas-limiting goals (New York and Illinois). But others view these subsidies as unfair advantages – Dynegy's CEO says that company will have to close 1,835 MW of coal-fired generation in Illinois because Exelon's subsidized nuclear plants can bid lower in the MISO capacity auction, setting capacity prices so low that Dynegy's coal plants can't recover their costs.[73]

For all the reasons outlined above, the EIA AEO estimates that another --- MW of nuclear generation is at risk of closure by 20xx.

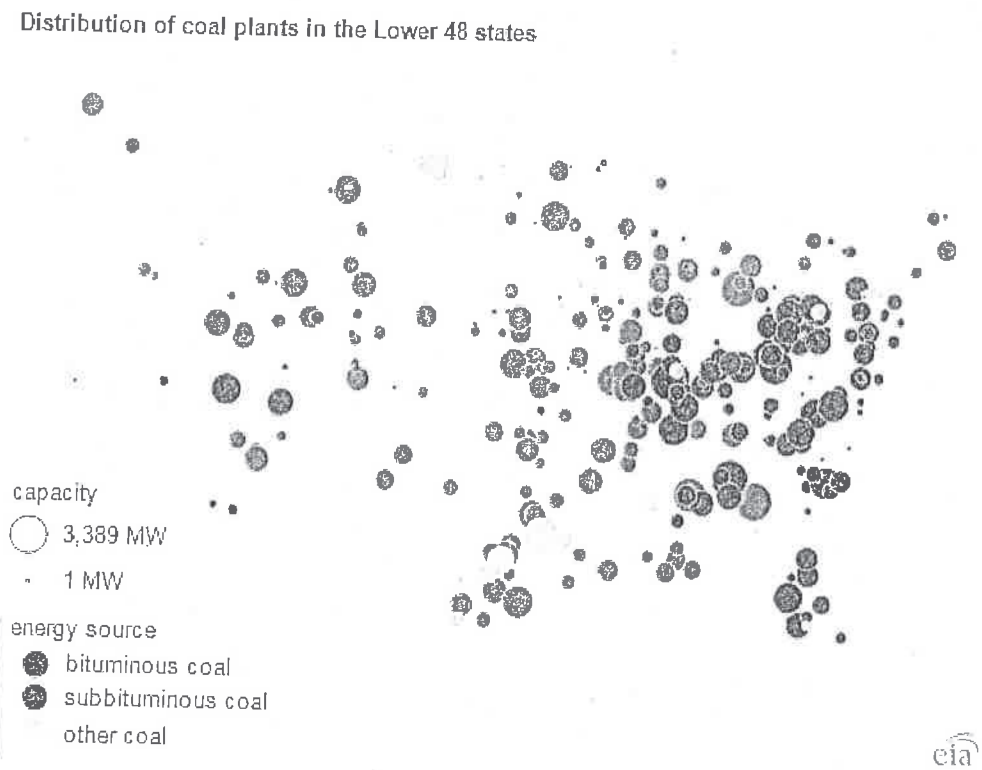
# 3.9 Consequence -- coal plant retirements

There were – coal-fired power plants in the U.S. at the start of 2002 and --- at the end of 2016. 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.
>
> About half of the coal capacity operating in 2016 use bituminous coal as their main energy source, a type of coal that comes from Appalachian states such as West Virginia, Kentucky, and Pennsylvania. Bituminous coal is the most abundant in the U.S. and is more commonly produced in eastern and midwestern states. Bituminous coal has a greater range of sulfur content. The other half of coal plants use subbituminous coal, which is mostly produced in western states such as Wyoming and generally has a lower sulfur content than most bituminous coals. Less than 5% of operating coal capacity uses lignite [principally in Texas] or other coal types.

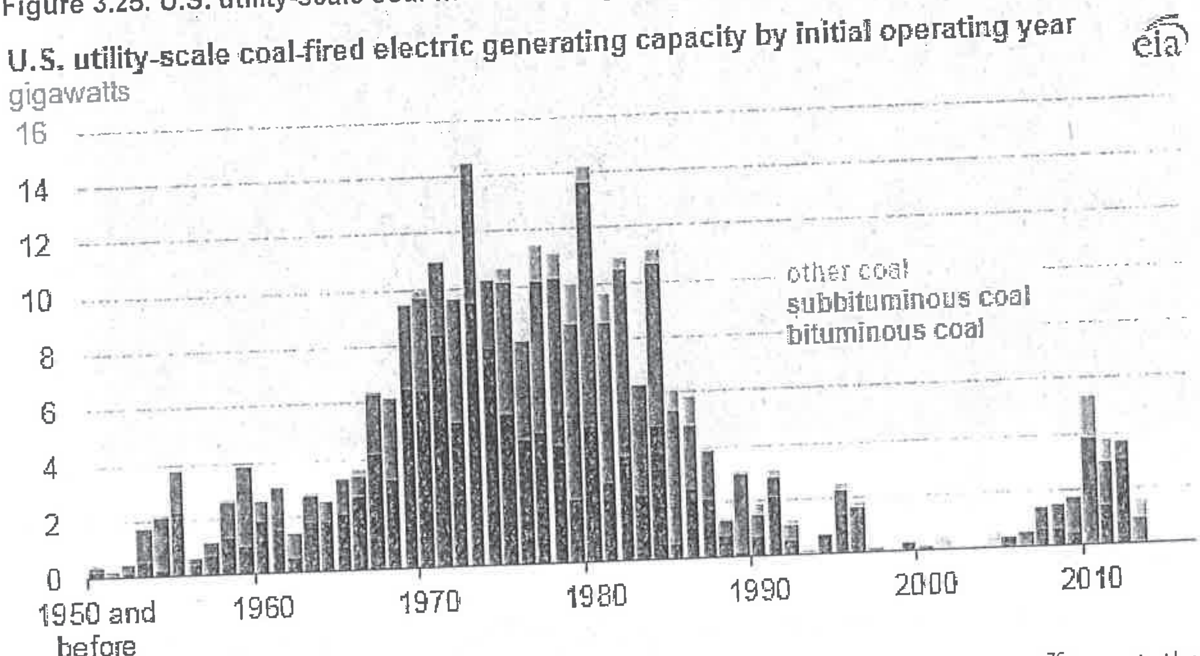
Most coal-fired generation is located in the east, as shown in Figure x. Nearly all coal consumed in the U.S. is used for power generation. Coal energy production peaked in 2007 and has been declining since. No new coal plants have been built for domestic utility electricity production since 2013 because new coal plants are more expensive to build and operate per kW and kWh than natural gas-fired plants. [need EIA cite]

**Figure 3.24. Location of coal plant retirements**



As shown in Figure 3.25, almost all coal plants were built before 1990[74]/ The service life of coal-fired generators reportedly, "average between 35 and 50 years, and varies according to boiler type, maintenance practices, and the type of coal burned, among other factors."[75]

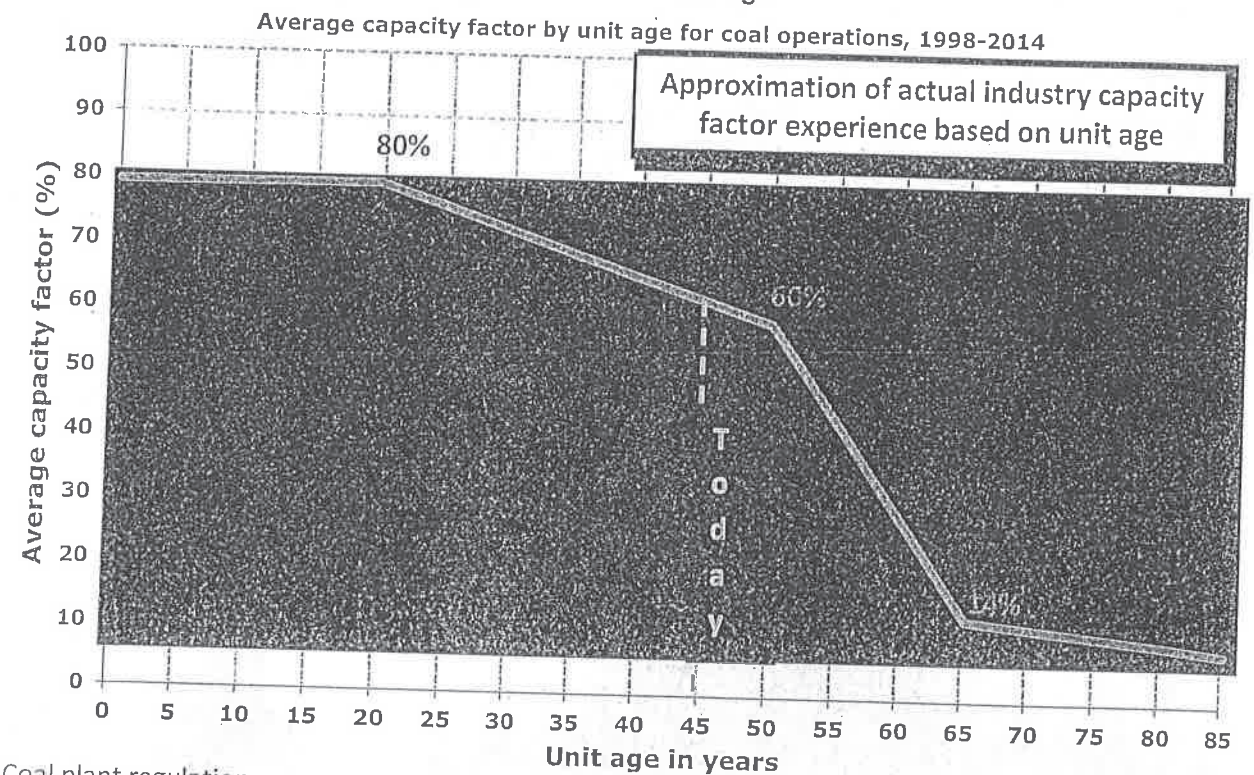
**Figure 3.25. U.S. utility-scale coal-fired electric generating capacity by initial operating year**




A review of the literature about coal plant cycling by the Argonne National Laboratory[76] reports that coal plant heat rates (fuel use per kWh of generation, expressed in Btu/kWh) increase with plant age, while plant availability decreases. Cycling and load-following exacerbate the effects of plant aging and reduce component life. These operational patterns impose higher maintenance costs as well as higher fuel costs.

A NETL report[77] indicates that younger coal plants have much higher capacity factors than older coal plants – likely because they have better fuel efficiency and produce electricity at a lower price per kWh. (See Figure 3.26) That report also finds that plant damage from cycling increases and accelerates over time with continued cycling, and that forced outage rates are more than double for plants that cycle than plants that run in steady baseload operation. Most of the coal plants retiring over the past few years were load-following in 2008-2014 (probably because the operators planned to run them hard without major reinvestment until the retirement date).

**Figure 3.26. Coal unit capacity factors decline as units age**[78]




<u>Coal plant regulation</u>

Coal plants have been the focus of more environmental regulation than any other type of generation. Ten environmental regulations adopted by the Obama administration implemented environmental statutes adopted as far back as 1970:

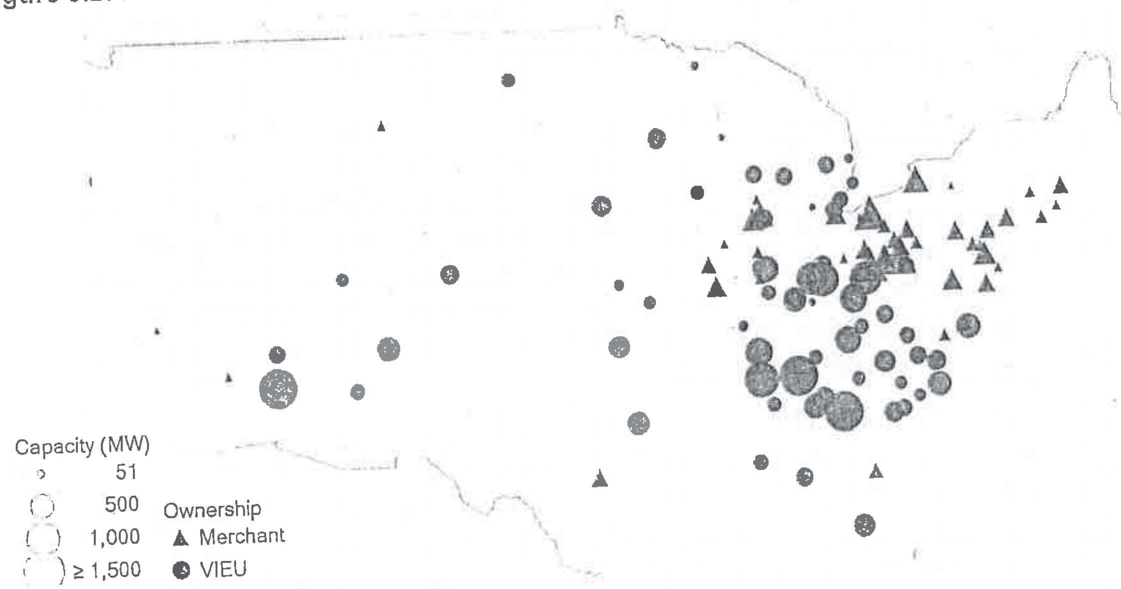
- Cross-State Air Pollution Rule (CSAPR) to reduce SO2 and NOx emissions (finalized June 6, 2011, updated September 7, 2016)
- Mercury and Air Toxics Standards to limit mercury, acid gases and other toxic pollution from power plants (adopted February 16, 2012)
- National Ambient Air Quality Standards (NAAQS) to strengthen emission reductions for particulate matter, a major source of respiratory illness (adopted January 15, 2013)
- Cooling Water Intake, standards on discharges of cooling water intake systems from electric plants and other industrial facilities, to protect aquatic species (adopted August 15, 2014)
- Coal Combustion Residuals limiting coal ash disposal (adopted April 17, 2015)
- Carbon Pollution Standards for New Plants, requiring all new, modified or reconstructed coal-fired plants to be equipped with carbon capture and sequestration technology (CCS) (Adopted August 3, 2015)
- Effluent Guidelines limiting the levels of toxic metals in wastewater that can be discharged from power plants (adopted September 30, 2015)
- Clean Power Plan to limit carbon dioxide emissions from existing power plants, scheduled to take effect in 2022 (finalized October 23, 2015 and stayed by the Supreme Court on February 9, 2016)
- NAAQS for ground-level Ozone (adopted October 26, 2015)
- Stream Protection Rule to address water pollution from underground and surface mining (finalized December 20, 2016 and disapproved by President Trump on February 16, 2017).

Only four of these regulations would have taken effect before 2016, but the prospect of having to meet all of them (particularly MATS, widely regarded as requiring the most costly capital investments of all the regulations) caused many coal generation owners to reevaluate whether it would be cost-effective to keep operating or retire their assets.

Coal plant retirements

Between 2002 and 2016, -- coal plants representing 53,604 MW of generation capacity had retired from the U.S. generation fleet; 33% of coal production disappeared between 2011 and 2016. Figure x shows that those coal plant retirements are concentrated in the eastern U.S. It has been claimed that, "industry practices, under positive economic conditions, is to replace the baseload asset base before [each power plant] reach[es] age 60."[79] EIA reported that coal-fired power plants made up more than 80% of the 18 GW of electric generating capacity 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."[80]

**Figure 3.27: Location of Coal Retirements, January 2002 to March 2017**[81,82]




An analysis of plants that have retired and those that have announced retirements indicates a few important trends and attributes. First, about 70% of the plants that have retired between 2010 and 2016 had a capacity factor of less than 50% in the year prior to retirement, and about half of the future planned retirements operated below a 50% capacity factor in 2016. Coal unit capacity factors consistently declined with plant age, reflecting the fact that younger coal plants use more modern technology with better heat rates and thus lower per kWh production costs. (See Figure 3.27) Second, while none of the retired units between 2010 and 2016 had significant $SO_2$ control equipment installed, more than half of the future announced retirements have SO2 control. The average size of planned retirements (380 MW) exceeds the average size of recent retirements (218 MW), indicating that future retirements are in general larger than plants that have already retired.

The conclusion to be drawn from these points (as verified in the map above) is that until quite recently, the coal plants that have retired have been those that 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 – these plants were fully exposed to competition from other generators and fuel types, while investor-owned plants in the southeast and elsewhere enjoyed a longer period of protection from low market prices.

Factors affecting coal plant retirements

The Navajo coal plant is a good example of the problem facing coal plants. Built in --, the 2.25 GW plant, located in the Navajo Nation and fed by a mine-mouth coal plant, is owned by four utilities that serve Arizona and Nevada; one quarter of the plant is owned by the federal government, which uses the energy to power pumps at the Central Irrigation Project. In 2017 the utilities announced an agreement with the Navajo Nation to retire the plant at the end of 2019, "based on the rapidly changing economics of the energy industry, which has seen natural gas prices sink to record lows and become a viable long-term and economical alternative to coal power."[83] This decision preceded two future cost increases that would affect the Navajo plants: one due to begin after 2019 once a new site lease with the Navajo Nation was to take effect, and a pollution control upgrade that the Environmental Protection Agency had allowed the utilities to defer to 2028-2030.[84] The cost of energy production at the Navajo Generating Station (NGS) was clearly rising – NREL estimated production costs at $32/MWh in 2015, $38/MWh in 2016, $41/MWh in 2019 after the new coal lease terms take effect, and $51/MWh after the emissions standards take effect.[85] Generation share had been shifting gradually from coal to natural gas and non-hydro renewables for almost two decades in the Southwest and the rest of the Western Interconnection. The region is over-supplied with coal, natural gas-fired, wind and solar generation, and with low gas prices the utilities could buy natural gas-fired electricity at the Mead Hub for only $25/MWh in 2016, well below the cost of energy from the NGS. In 2016, replacing NGS power with market-priced resources would have saved CAP water customers about $38.5 million.[86] On the other hand, closing NGS would result in the loss of about 548 permanent jobs at the plant, and potentially about 422 jobs at the nearby coal mine which supplies NGS. Native Americans -- mostly Navajo and Hopi -- make up between 80% and 90% of the workforce.[87]

Several other large coal plants built after 1970 with capacities greater than 1,000 MW that have announced plans to retire in the next few years. These plants have already made the capital investments to comply with the MATS environmental regulations, so that deadline is not a forcing factor in the retirement decision. Although these plants too were designed to operate around the clock, low wholesale electric prices tied to natural gas are causing those plants to be operated at lower capacity factors, dropping their cash flow into the red. One observer comments, "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."[88]

## Coal plant retirements caused by low natural gas prices and low demand

**Source: "Can Coal Make a Comeback?", Trevor Houser, Jason Bordoff & Peter Marsters,Columbia University, Center on Global Energy Policy, April 2017**

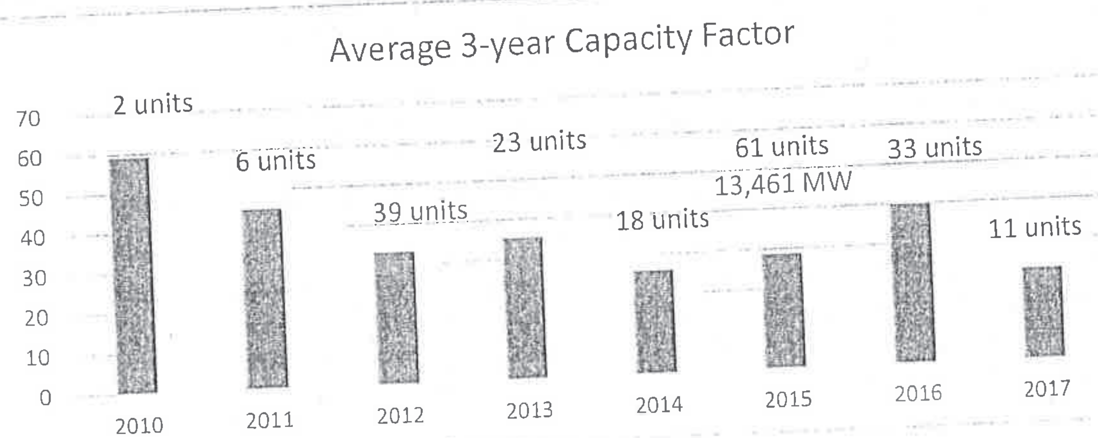
This paper offers an empirical diagnosis of what caused the coal collapse....

U.S. electricity demand contracted in the wake of the Great Recession, and has yet to recover due to energy efficiency improvements in buildings, lighting and appliances. A surge in U.S. natural gas production due to the shale revolution has driven down prices and made coal increasingly uncompetitive in U.S. electricity markets. Coal has also faced growing competition from renewable energy, with solar costs falling 85% between 2008 and 2016 and wind costs falling 36%.

Increased competition from cheap natural gas is responsible for 49% of the decline in U.S. goal consumption. Lower than expected demand is responsible for 26%, and the growth in renewable energy is responsible for 18%. Environmental regulations have played a role in the switch from coal to natural gas and renewables in U.S. electricity supply by accelerating coal plant retirements, but were a significantly smaller factor than recent natural gas and renewable energy cost reductions.

Like fossil units, many coal plants have retired or are at risk of retirement because their marginal cost of production is greater than prevailing electric market prices. As early as 2012, coal plant owners were warning EIA that they expected to retire almost 27 GW of capacity from 175 coal-fired generators between 2012 and 2016.[89] The coal units that retired between 2009 and 2011 were small, with an average size of only 59 MW and a low fuel conversion efficiency (heat rate); the units that have retired since are younger and more fuel-efficient, but today they are being dispatched less often (see Figure x) because they are more costly than alternate energy sources.

**Figure 3.28. The coal plants that retired had low capacity factors[90]**




Average three-year capacity factor for the coal plants retiring in each of the listed years

Coal's high cost challenge is evident even in coal country. In West Virginia, the leading utility has closed three coal-fired plants and converted two others to gas, lowering its coal dependence from 74% in 2012 to 61% last year, and the Kentucky Public Service Commission encourages its utilities to offer business customers renewable energy packages.[91] And the Kentucky Coal Museum has installed 80 solar panels on its roof to save money to save between $8,000 and $10,000 per year on electric bills that have been running about $2,100 every month.[92]

## Coal plant closure considerations

**Source: "Coal Power Plant Post-retirement options," O'Malley, Power, 9/1/16**

The primary recent drivers of retirement announcements have been 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 have included 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 under 300 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 MATS deadlines have passed, additional closures are being announced by companies 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 (Table 1)

Power plant decommissioning and redevelopment projects are all about risk, money, and who pays. When a power plant shuts down, revenue ceases but costs do not. Some owners quantify their costs, which may be allocated over many cost centers. Best-in-class companies also determine real estate valuations and exit strategy costs so they can make informed decisions about whether to redevelop, hold, or sell.

"Who pays" has emerged as a very interesting question. In states that are still regulated, decommissioning costs could be passed through to ratepayers, subject to public service commission approval. In deregulated states, shareholders would pay for decommissioning, subject to management approval.

... As a Genco, if you are in a Regional Greenhouse Gas Initiative state where you can recover the cost of closing plants through the rate base, it is often wise to do so. In deregulated states, conversely, shareholders have to pay for those costs up-front, and more case-making must typically be done to secure board approval for the $10 million to $20 million price tag.

# 3.10 Consequence – natural gas-fired power plant retirements

EIA reports on the U.S. gas-fired generator fleet:[93]

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.

Natural gas-fired combined-cycle units accounted for 53% of the 449 gigawatts (GW) 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. Under current natural gas and coal market conditions in many regions of the country, combined-cycle generating units are often used as baseload generation, which operate throughout the day.

Other types of natural gas-fired technology, such as combustion turbines (about 28% of total natural gas-powered generator capacity) and steam turbines (17%), 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), and nuclear (36).

Figure 3.29 shows the on-line dates for the three types of natural gas-fired power plants.

**Figure 3.29. Most natural gas-fired generation built after 2000[94]**

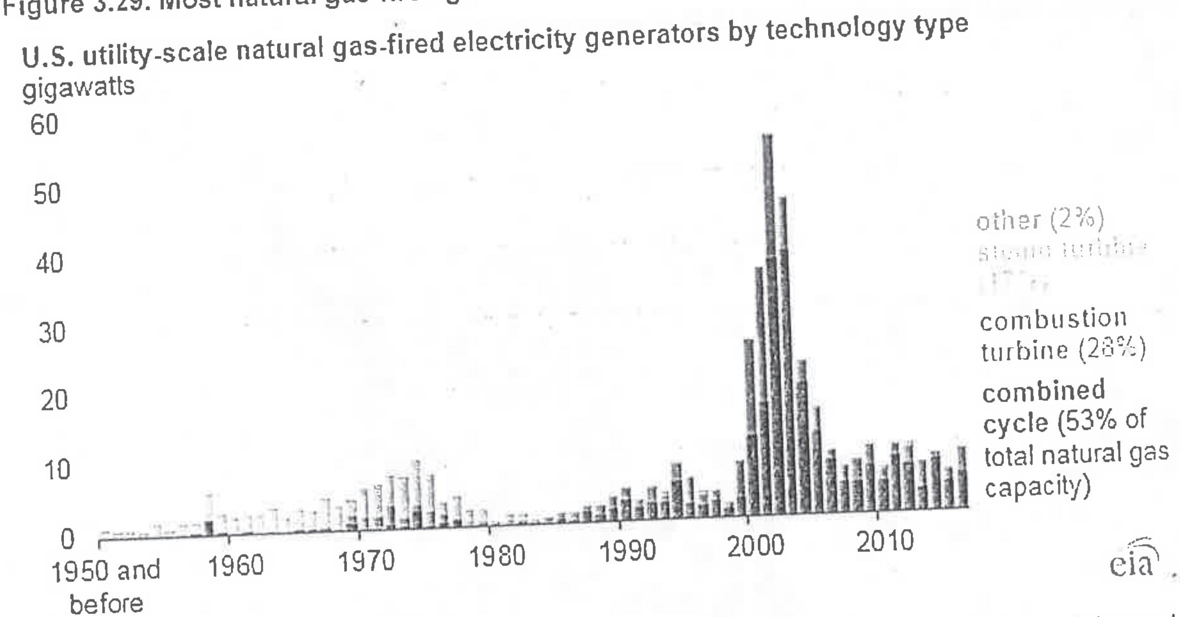



Figure 3.30 shows total natural gas-fired net generation and how the capacity factors of these plants vary by technology over the years 2011 through 2016. Although steam turbines were originally built principally for relatively stable baseload use, those plants are being displaced in the dispatch merit order by more efficient combined cycle plants and combustion turbines, both of which are designed for greater flexibility and are often located closer to loads than the large steam plants. This is shown in Figure 3.Z. 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. NREL reports that the due to the flexibility, efficiency and cost-competitiveness of natural gas combined cycle power plants, grid operators have been dispatching NGCC plants more frequently as baseload generators. In consequence, the capacity factor for all NGCC plants has grown from about 40% in 2008 to roughly 56% in 2016, surpassing that of coal.[95]

Figure 3.30. Natural gas fleet net generation and capacity factors[96]

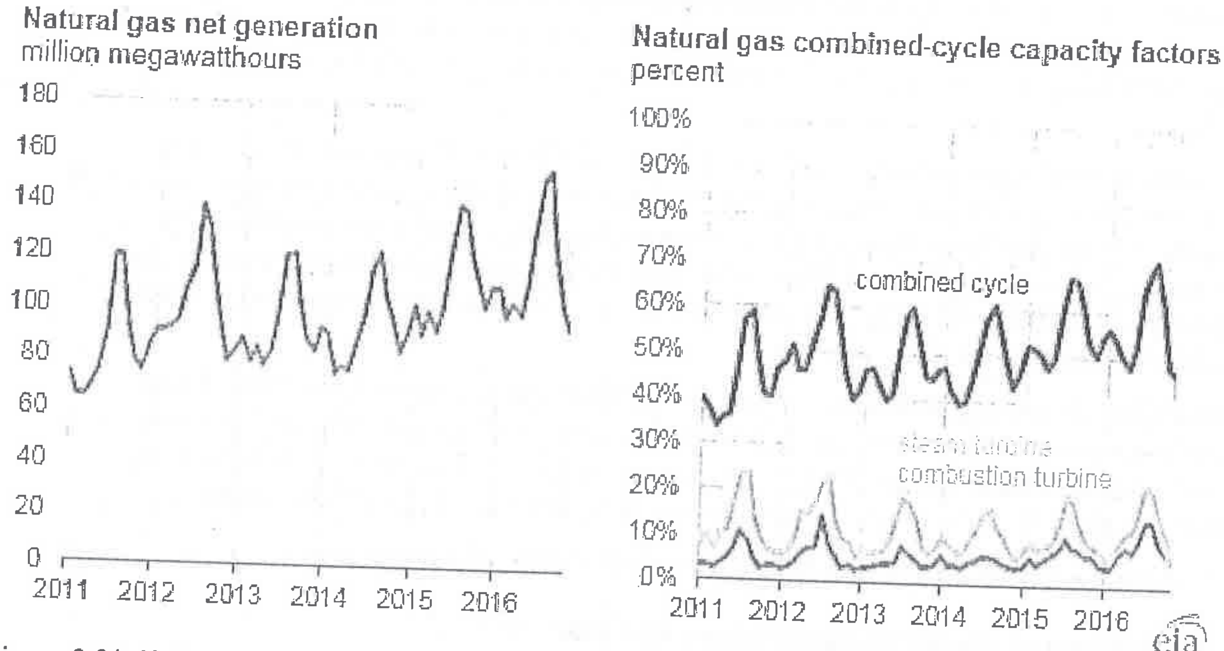
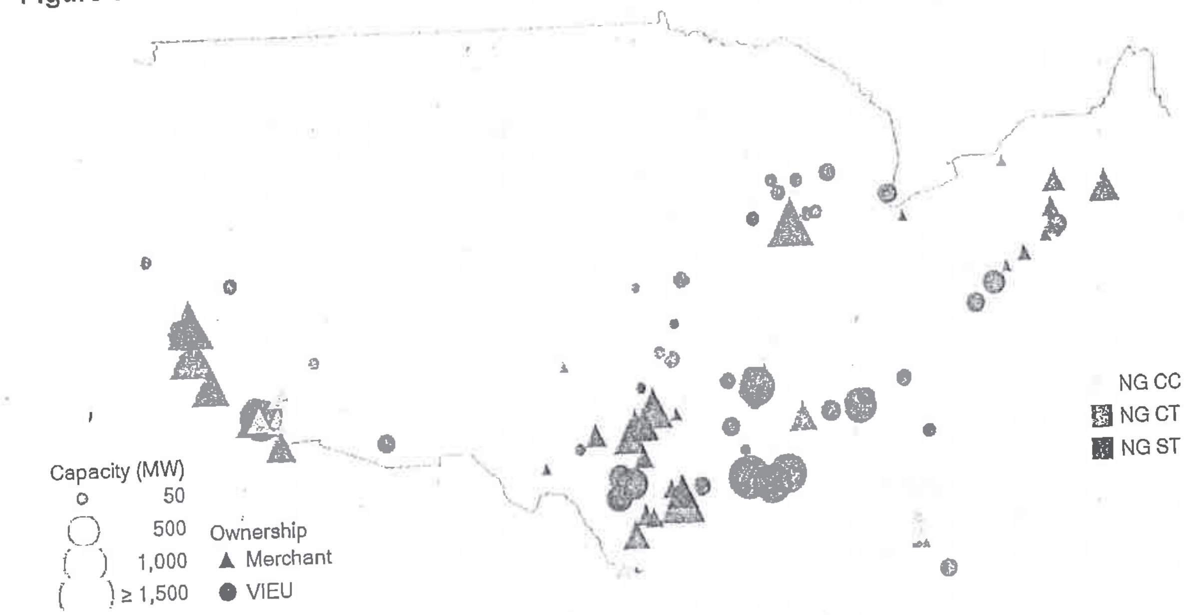



Figure 3.31. Natural gas-fired plants serve most of the Lower 48 states[97]


## Natural gas plant retirements

As noted above, Texas has been an inhospitable environment for merchant gas plants. So has California, where merchants bought the utilities' old gas plants during the early days of asset divestitures and discovered that some of the gas-fired plants were better off retired. More broadly, because it's relatively easy to build a natural gas-fired power plant in most regions, volatile commodity prices along with an excess of gas capacity contributed to significant retirements of the older, less efficient generators. EIA reported in 2011 that between 2000 and 2010, 33 GW of net summer capacity natural gas-fired generation retired (72% steam turbines), with an average age of 48 years. In 2010, the average steam turbine operated at a heat rate of 2,000 Btu/kWh more than the average combined cycle plant.[98]

**Figure 3.32: Location of Natural Gas Retirements, January 2002 to March 2017[99] [100]**




Not all plant retirements are caused by the invisible hand of the electric market weeding out old, inefficient power plants to improve system efficiency and costs for everyone. Sometimes there is a regulatory or state policy forcing the retirement.

1534

## "Californians are paying billions for power they don't need"

**Source: Ivan Penn & Ryan Menezes, LA Times, February x, 2017)**

At its 2001 launch, the Sutter Energy Center was hailed as the nation's cleanest power plant. It generated electricity while using less water and natural gas than older designs.

A year ago, however, the $300-million plant closed indefinitely, just 15 years into an expected 30- to 40-year lifespan. The power it produces is no longer needed — in large part because state regulators approved the construction of a plant just 40 miles away in Colusa that opened in 2010.

Two other large and efficient power plants in California also are facing closure decades ahead of schedule. Like Sutter, there is little need for their electricity.

California has a big — and growing — glut of power, an investigation by the Los Angeles Times has found. The state's power plants are on track to be able to produce at least 21% more electricity than it needs by 2020, based on official estimates. And that doesn't even count the soaring production of electricity by rooftop solar panels that has added to the surplus.

To cover the expense of new plants whose power isn't needed — Colusa, for example, has operated far below capacity since opening — Californians are paying a higher premium to switch on lights or turn on electric stoves. In recent years, the gap between what Californians pay versus the rest of the country has nearly doubled to about 50%.

This translates into a staggering bill. Although California uses 2.6% less electricity annually from the power grid now than in 2008, residential and business customers together pay $6.8 billion more for power than they did then. The added cost to customers will total many billions of dollars over the next two decades, because regulators have approved higher rates for years to come so utilities can recoup the expense of building and maintaining the new plants, transmission lines and related equipment, even if their power isn't needed.

How this came about is a tale of what critics call misguided and inept decision-making by state utility regulators, who have ignored repeated warnings going back a decade about a looming power glut.

... California regulators have for years allowed power companies to go on a building spree, vastly expanding the potential electricity supply in the state. Indeed, even as electricity demand has fallen since 2008, California's new plants have boosted its capacity enough to power all of the homes in a city the size of Los Angeles — six times over. Additional plants approved by regulators will begin producing more electricity in the next few years.

The missteps of regulators have been compounded by the self-interest of California utilities.... Utilities are typically guaranteed a rate of return of about 10.5% for the cost of each new plant regardless of need. This creates a major incentive to keep construction going: Utilities can make more money building new plants than by buying and reselling readily available electricity from existing plants run by competitors.

... Sutter was built in 2001 by Houston-based Calpine, which owns 81 power plants in 18 states. Independents like Calpine don't have a captive audience of residential customers like regulated utilities do. Instead, they sell their electricity under contract or into the electricity market, and make money only if they can find customers for their power.

... [The CEO of Calpine says,] Independent plants are closing early ... because regulators favor utility companies over other power plants.

... So that California utilities can foot the bill for these plants, the amount they are allowed by regulators to charge ratepayers has increased to $40 billion annually from $33.5 billion, according to data from the U.S. Energy Information Administration. This has tacked on an additional $60 per year to the average residential power bill, adjusted for inflation. ... The average cost of electricity in the state [California] is now 15.42 cents a kilowatt hour versus 10.41 cents for users in the rest of the U.S. The rate in California, adjusted for inflation, has increased 12% since 2008, while prices have declined nearly 3% elsewhere in the country.

**"Gas Apocalypse' Looms Amid Power Plant Construction Boom" Source: Naureen Malik, Bloomberg News, May 23, 2017) https://www.bloomberg.com/news/articles/2017-05-23/-gas-apocalypse-looms-amid-power-plant-construction-boom**

The glut of cheap natural gas from a single, gigantic, shale basin that straddles the Northeast, mid-Atlantic and Midwest has sparked a massive construction boom of power plants. Dozens have been built in the past two years alone.

There's just one problem: There isn't nearly enough electricity demand to support all the new capacity. And as wholesale electricity prices plunge, industry experts are anticipating a fire sale of scores of plants in the region. Many, in fact, have already been sold along the PJM Interconnection LLC grid, the nation's largest, encompassing 13 states from Virginia to Illinois.

"Everything in fossil fuels is for sale," said Ted Brandt, chief executive officer at Marathon Capital LLC, a mergers-and-acquisitions adviser in Chicago. "People are bleeding."

... Drawing from abundant, cheap and nearby natural gas in the country's most prolific shale field, the new plants are adding a gigantic amount of power generation -- more than 20 gigawatts --- to a region that arguably has more than it needs. The new gas-fired plants are also coming online at a time of market turmoil, buffeted by Obama administration efficiency policies that have helped tamp down demand and by the Trump administration's determination to keep old coal-fired plants going.

Spot wholesale prices at PJM's benchmark Western hub slumped to an average of $28.79 per megawatt-hour last year, falling by more than half since 2008 as the shale boom took hold. Many players are exiting the market.

Calpine Corp. -- the highly leveraged Houston-based independent power producer with a more than $4 billion market value and 17 plants in the PJM grid -- is exploring a sale of its facilities. The company has attracted interest from private-equity firms, Bloomberg reported this month. And FirstEnergy Corp. and American Electric Power Co. took more than a combined $11 billion in 2016 charges for plants. They're exiting production to focus on buying and distributing electricity. Dynegy Inc. has also been reported as a takeover target.

"It's a gas-driven apocalypse in the power market," said Toby Shea, a New York-based analyst at Moody's Investors Service.

## 3.11 Not a consequence – hydropower retirements

The EIA reports that conventional hydroelectric generation accounts for 79.6 GW or 7% of the nation's operating electricity generating capacity and 6-7% of its energy production each year.[101] Half of U.S. hydro capacity is located in Washington, California and Oregon. About half the U.S. hydroelectric fleet is over 50 years old since many large dams were built between the 1940s and 1960s;[102] the average hydroelectric facility has been operating for 64 years.[103] 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.

Hydroelectric plant operation is constrained by factors such as whether the plant has a storage reservoir or is run-of-river, the availability of streamflow (which is in turn affected by seasonal rainfall and snowpack), and the water usage requirements of irrigation, navigation, recreation and fisheries protection needs. A hydro plant's operation may vary widely between seasons -- the average capacity factor of conventional hydroelectric generators was 40 percent.[104]

Hydro facilities can help to balance the output from variable generating resources, which they do in CAISO through local resources and the Energy Imbalance Market. Hydro provides primary frequency response, especially in the Western interconnection. Hydro facilities are often black-start facilities, which energize the grid after a blackout. Finally, hydro facilities may provide ramping and reactive power support. The degree to which any given facility can provide these services depends on a range of engineering, environmental, and economic factors. Pumped storage projects in particular can assist in the integration of renewable resources into the electrical grid by pumping water into storage during high renewable output periods and generating electricity in the hours when the renewable resource is unavailable.

FERC regulates over 1,600 non-federal hydropower projects at over 2,500 dams, half of the U.S. hydropower capacity. Many hydro facilities are licensed by FERC for up to 50-year terms. It takes an average of 5 to 8 years to relicense an existing hydro project, with at least 3 years of pre-filing activity and then at least another 2 years after the application is filed. New (extension) licenses can be for terms between 30 and 50 years. Most of the hydro plants that are not regulated by FERC are owned by federal or state agencies such as BPA and the Federal Bureau of Reclamation.

A few 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 upgrades (initiated by the plant owner rather than a regulator), dam safety upgrades, or environmental improvements. FERC reports that most hydro plants are relicensed.

There has been some concern over whether some of these aging hydro plants are retiring. EIA public reports indicate that 1,376 MW (of the total 79.6 GW of U.S. hydroelectric capacity) retired between 2002 and 2017. The EIA looked into the question whether these hydro plants have actually retired in recent years. The agency found that most of the plants recorded as retired had not ceased operation, but rather have been modified with measures such as turbine replacement, creating a misleading classification. Only 52 real hydroelectric plants retired, representing 273 MW of generation capacity, in the sense that they have been decommissioned or wholly removed from the host site.[105]

# 3.12 Premature retirements – what's premature?

Many of the retired and retiring plants are unable to provide the services that are needed to maintain reliability on a more fast-moving, high-variability bulk power system. Even if they could provide more ramping and cycling services without high cost to the plant, most of these legacy plants cost more per MWh than other market sources.

While some of the nuclear units now closing are doing so because of either state policy pressure (as with California's Diablo Canyon and New York's Indian Point), and some have damages that are too costly to fix, most are closing or threatening closure because nuclear power has become unable to compete against low-cost gas-fired generation and renewables with low electric demand. The case can be made that well-functioning nuclear plants which have made appropriate investments to upgrade and refresh their facilities, received license extensions, and complied with all environmental regulations -- but are now being forced to retire anyway because market prices are so low – face premature retirement. It is clear that nuclear energy offers benefits, particularly as a zero-emission energy source;

but as gas prices stay flat, renewables grow and demand stays flat, it is not clear yet whether the subsidies that some states are willing to pay to keep these plants in operation will be sufficient to support a total revenue stream that covers each plant's full cost over time.

The early coal plant retirements were smaller, inefficient units that retired because they could not compete against lower-priced coal, natural gas and nuclear generation. More recently, many older coal plants became uneconomic as market electric prices declined; they were being dispatched less frequently and could not earn enough revenues to recover operating costs, much less recover sunk capital costs or the prospective capital and operating costs required to comply with increasing environmental regulations. Many of these now-retired plants would have already have been retired or scheduled for retirement or upgrades before now had natural gas prices not sunk, to drop effective gas prices per MWh below coal prices. Only a few cases, like the new, highly efficient Navajo plant, appear to merit a claim that the plant is being forced to retire prematurely, while it still has value to contribute to the grid.

There is no good definition yet for the term, "premature retirement." When used with respect to legacy power plants, the term "premature retirement" often means, it had to retire before the owner or advocate was ready to retire it.... A more analytical consideration of the term would involve looking into questions such as:

- Has the plant already operated past its design lifetime (possibly with modifications and upgrades)?
- Had the owner of the plant already achieved full rate recovery for its capital costs (particularly for VIEU-owned, ratebased plants)?
- What's the cost of keeping an old plant going? If the plant is out of the money relative to other energy sources, how much additional investment will it take to make it efficient and competitive? Will or can that investment be recovered?
- What are the opportunity costs of keeping an uneconomic generator from retiring? How much less would an electric utility's energy portfolio cost if it no longer had to support and buy energy from an out-of-the-money generator?[u]
- What are the societal costs and benefits of retirement v. non-retirement? What are the non-monetary costs of keeping a plant open (e.g., on-site nuclear storage absent a federal nuclear waste repository, or pollution affecting communities near the plant)? What are the non-monetary benefits of keeping it open (e.g., local voltage support, inertia for grid-stabilizing frequency response, or zero-emissions pollution?
- If you think a legacy plant should be forced to stay open rather than retire, is it appropriate to burden its shareholders by trying to keep the plant open through multiple years of losses?
- If you think a legacy plant should be subsidized to stay open rather than retire, will the magnitude of the subsidy contemplated be sufficient to overcome the revenue shortfall for long? Will the benefits realized from keeping the plant open outweigh the societal costs of the transfer payment from a large group of taxpayers or electric customers to the power plant owners?
- Is there a more effective way to attain the benefits sought from preventing power plant retirement than actually paying to keep it open? If the goal sought is clean energy, is there a cheaper way to get it than nuclear generation? If the goal is to protect grid inertia, are there other ways to maintain or improve inertia? If the goal is to protect community jobs, can

[u] State regulators and utility executives wrestle with this question constantly through Integrated Resource Planning processes and utility rate cases, and they are the ones initiating many recent legacy plant retirements.

community economic development, job training programs and community development grants provide an effective community transition as effectively and cost-effectively as keeping a power plant open?

# 3.13 Baseload retirements – looking forward and next steps

The role of baseload resources continues to evolve, and the financial strains on baseload coal, nuclear and natural gas plants are real and significant. If current retirement trends continue, many more coal and nuclear plants could retire over the coming decade. It is certain that more natural gas and renewable generation capacity can come on-line quickly (although much less certain that we have sufficient transmission to serve new remote generation). And it is probable that our grid managers have sufficient tools and resources to manage this change without a loss of grid reliability.

In most other industries, the problem of over-supply and brutally low prices would be solved by the market pendulum swinging from over-capacity to under-capacity as sustained low market-clearing prices drive all of the inefficient competitors out of business. In such a circumstance, scarcity would create high prices, which would eventually lure more competitors back into the market, and the cycle would continue.

But this is electricity, not a commodity market, and our society cannot afford to risk grid reliability and affordability. Unlike commodity markets, electric utilities cannot react quickly – in part because their regulatory institutions don't allow them to do so. Thus, as the Secretary directs, we should look for ways to manage this difficult transition to assure that we protect grid reliability and cushion the communities and customers affected by these changes.

Several issues relating to baseload retirements deserve further research:

- What is the value of retaining nuclear power plants to maintain some minimum level of system inertia and emissions-free energy?
- Nuclear plants in the French fleet routinely cycle, while U.S. nuclear plants don't. Are there modifications we can make to U.S. plants to make them more flexible?
- Are there ways to lower the marginal operating costs of nuclear and coal plants without compromising sustainability and safety goals?

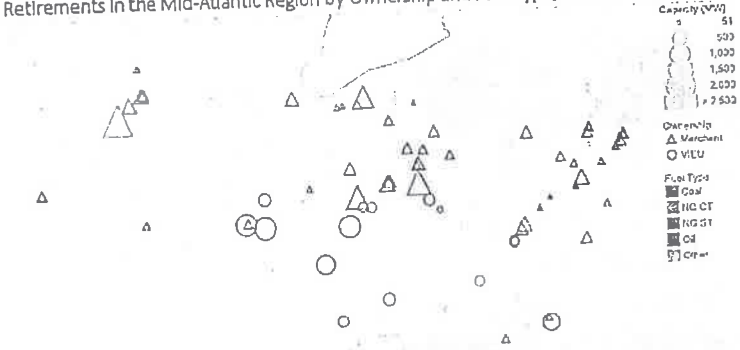
# 3.14 Regional Profiles

This section will contain nine regional profiles with information on retirements, diversity, and more, with commentary on the trends and conditions particular to each region.

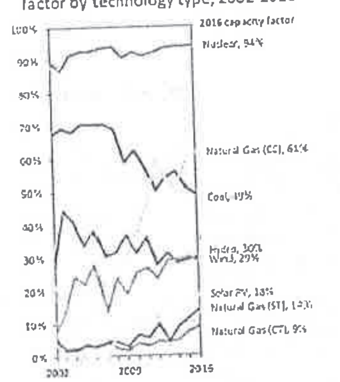
The page that follows is an example of the information coming in each regional profile.

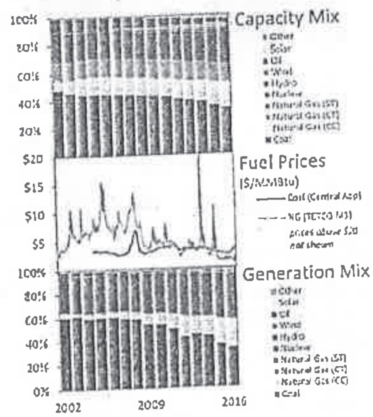
## Mid-Atlantic Regional Profile

**Retirements in the Mid-Atlantic Region by Ownership and Fuel Type, 2002 through 2017.**




Mid-Atlantic capacity-weighted average capacity factor by technology type, 2002-2016




| Regional Statistics | 2002 | 2016 |
|---|---|---|
| Utility-scale capacity (MW) | 172,931 | 186,746 |
| Utility-scale generation (MWh) | 820,790,355 | 810,903,642 |

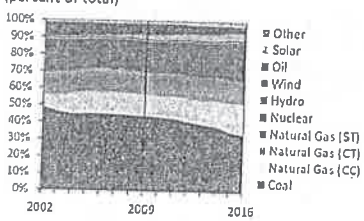
| Retirements by Energy Source, 2002-2017* | | |
|---|---|---|
| *2017: Q1 actual, Q2-4 announced | # of Plants | MW |
| Coal | 65 | 23,526 |
| Natural Gas | 41 | 6,923 |
| Nuclear | 0 | 0 |
| Oil | 60 | 5,326 |
| Hydro | 2 | 3 |
| Biomass | 5 | 168 |
| Wind | 1 | 10 |
| Solar | 0 | 0 |
| Other | 41 | 199 |

| NERC Reserve Margin for 201x | |
|---|---|
| Target % | xx% |
| Current % | xx% |

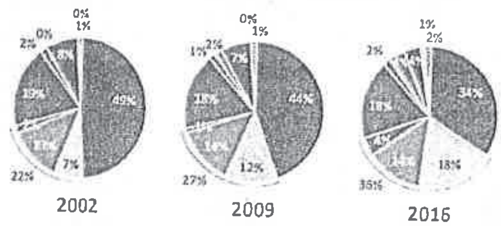
| Current Resources, 2016 | Capacity (MW) | Growth Rate? |
|---|---|---|
| Coal | 63,147 | ? |
| Natural Gas | 67,157 | ? |
| Nuclear | 33,830 | ? |
| Oil | 7,197 | ? |
| Hydro | 3,331 | ? |
| Wind | 7,484 | ? |
| Solar | 1,476 | ? |
| Other | 3,124 | ? |

| Ownership Trends | VIEU | Merchant |
|---|---|---|
| % of Retired Capacity 2002-2017 | 24 | 76 |
| % of Current Capacity | 28 | 72 |

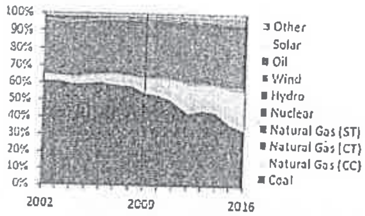
Mid-Atl utility-scale generating capacity
(percent of total)



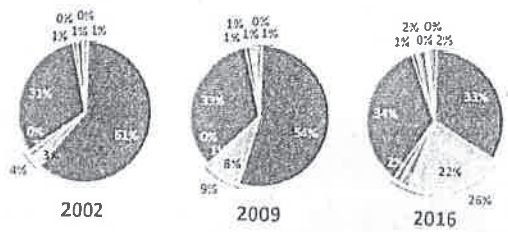

Mid-Atl utility-scale capacity mix




Mid-Atl utility-scale electrical energy
(percent of total)




Mid-Atl utility-scale generation mix




Mid-Atl utility-scale generating capacity, 2002 vs. 2016

| Technology | 2002 | | 2016 | |
|---|---|---|---|---|
| | MW | Percent of Total | MW | Percent of Total |
| Coal | 84,568 | 49% | 63,147 | 34% |
| *Natural Gas (all)* | *37,420* | *22%* | *67,157* | *36%* |
| Natural Gas (CC) | 12,053 | 7% | 33,635 | 18% |
| Natural Gas (CT) | 22,347 | 13% | 25,375 | 14% |
| Natural Gas (ST) | 3,020 | 2% | 8,147 | 4% |
| Nuclear | 32,620 | 19% | 33,830 | 18% |
| Hydro | 2,854 | 2% | 3,331 | 2% |
| Wind | 100 | 0% | 7,484 | 4% |
| Oil | 13,326 | 8% | 7,197 | 4% |
| Solar | | 0% | 1,476 | 1% |
| Other | 2,042 | 1% | 3,124 | 2% |
| Total | 172,931 | | 186,746 | |

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Mid-Atl utility-scale electrical energy, 2002 vs. 2016

| Technology | 2002 | | 2016 | |
|---|---|---|---|---|
| | MWh | Percent of Total | MWh | Percent of Total |
| Coal | 502,102,794 | 61% | 271,601,367 | 33% |
| *Natural Gas (all)* | *34,567,856* | *4%* | *212,945,249* | *26%* |
| Natural Gas (CC) | 22,509,779 | 3% | 181,069,575 | 22% |
| Natural Gas (CT) | 9,025,060 | 1% | 19,427,882 | 2% |
| Natural Gas (ST) | 3,033,017 | 0% | 12,447,792 | 2% |
| Nuclear | 255,924,849 | 31% | 278,804,277 | 34% |
| Hydro | 6,809,664 | 1% | 8,660,684 | 1% |
| Wind | 66,791 | 0% | 18,897,716 | 2% |
| Oil | 11,229,487 | 1% | 2,742,624 | 0% |
| Solar | - | 0% | 2,529,970 | 0% |
| Other | 10,088,914 | 1% | 14,721,754 | 2% |
| Total | 820,790,355 | | 810,903,642 | |

# 4 Reliability and resiliency

[UNDER CONSTRUCTION]

Most of the common metrics for grid reliability suggest that the grid is in good shape despite the retirement of many baseload power plants. Table 4.1 compares NERC-calculated reserve margins for 2011 and 2016 for all of the NERC regions, and shows that in most cases, reserve margins are still comfortably above each region's target margin.

**Table 4.1. NERC region reserve margins for 2011 and 2016**[v]

| Assessment Area | 2011-Y1 | 2016-Y1 |
|---|---|---|
| FRCC | 24.2% | 24.3% |
| MISO | 23.1% | 18.7% |
| NPCC-New England | 16.9% | 20.4% |
| NPCC-New York | 33.1% | 23.2% |
| PJM | 23.8% | 28.9% |
| SERC-E | 25.8% | 18.9% |
| SERC-N | 29.3% | 18.7% |
| SERC-SE | 22.7% | 32.6% |
| SPP | 26.7% | 27.2% |
| TRE-ERCOT | 16.9% | 14.5% |
| WECC | 39.7% | 26.8% |

These reserve margin estimates reflect 2016 conditions and forecasts of peak loads, generation, demand-side and transmission-enabled imported resources available at peak, and other factors. In every region but ERCOT, reserve margins remain (as of the 2016 calculation) comfortably or significantly higher than the levels which would raise a resource adequacy flag or signal potential reliability problems. However, even if the reserve margin is within a couple points of the target, having those resources does not guarantee reliability. Problems occur (hot weather, wind, drought, attacks), so the grid is always at risk. Since power plant retirements continue — as do additions of new capacity from natural gas and renewable plants and energy efficiency and demand response — the 2016 figures do not accurately describe 2017 conditions. We also don't know conditions five years out, although we can be confident that older, inefficient power plants will continue to retire. There is also a risk that planned power plants will not be built or will be delayed. NERC and North America's reliability coordinators conduct on-going analyses to assess resource adequacy as system conditions change over time.

NERC's 2016 Long-Term Reliability Assessment and the 2017 State of Reliability Report offer some common, positive findings:

- There were no severe grid events on the bulk power system in 2016.

[v] These are NERC planning reserve margins, which reflect a set of capacity-based region-specific forecasts and planning assumptions that are becoming less relevant as technology and economics and the growth of variable renewable energy move us toward a more energy-based system.

- Significant causes of system problems, including protection system mis-operations, are declining and have been declining for four years.
- Frequency response has been improving across all four interconnections, but still needs attention to assure that frequency is stabilized during system disturbances.
- Transmission outages aren't getting any worse.
- System resiliency to severe weather continues to improve.
- The gas-electric interface and our growing dependence on natural gas with the potential for a single point of extensive disruption remain a cause for concern.[106]

According to the North American Electric Reliability Corporation, current bulk power system reliability is an issue of risk management. In testimony to FERC on June 22, 2017, NERC CEO Gerry Cauley touched on both reliability and resiliency, commenting:

> [I]t is essential to continually identify and address emerging risks and their potential to significantly impact BPS reliability. Risk Policy and regulatory developments occurring with respect to renewable energy development, storage, conservation, demand response, and micro-grids have the potential to significantly affect BPS reliability. Market structures and developments also are impacting fuel supply, generation and transmission infrastructure planning, operations, and investment decisions. Given the rapidly changing generation resource mix, and related new technologies, it is critical to understand impacts on essential reliability services (ERS) – specifically frequency response, voltage support, and ramping capability. It is also important to appreciate the operating characteristics of new technology at the interface of the BPS. ...
>
> Substantial progress has been made in the last five years to improve coordination between natural gas pipelines, gas distribution companies, and electric industries. ... NERC [has] recommended incorporating fuel availability into national and regional assessments.
>
> Until recently, natural gas interdependency challenges were more often experienced during extreme winter conditions and focused almost exclusively on gas delivery through pipelines. However, the recent outage of an operationally-critical natural gas storage facility in Southern California — Aliso Canyon — demonstrates the potential risks to BPS reliability of increased reliance on natural gas without increased coordination between the two industries.

A recent DOE paper summarized the standards and regulations pertaining to power system reliability into four rules:

1. Power generation and transmission capacity must be sufficient to meet peak demand for electricity
2. Power systems must have adequate flexibility to address variability and uncertainty in demand (load) and generation resources
3. Power systems must be able to maintain steady frequency
4. Power systems must be able to maintain voltage within an acceptable range.[107]

QER on time scale of grid ops (S-11)

NERC on reliability

NERC data on regional reserve margins indicates that [fill in from NERC 2016 LTRA]

## 4.1 Reliability and current reliability performance

[UNDER CONSTRUCTION]

- Baseload plants deliver capacity and energy, but capacity and energy alone don't incent and deliver the essential reliability services necessary for
- Define products more appropriate to essential reliability services
- Use markets to improve reliability
- NERC reliability metrics show improvement
- Check SAIDI & SAIFI where available
- Reserve margins

*Yes and no -- Baseload power is not as necessary as it used to be. Baseload power was useful to a well-functioning grid over the decades from 1960 to 1990, when these plants were initially built. But with technology and market changes, the bulk power system has changed markedly and high-value market and reliability require different services and capabilities to attain high reliability and resilience. Therefore, baseload capacity erosion is not yet a problem for grid reliability and resilience – but further study is needed to determine how much more baseload capacity can be lost before grid reliability might be harmed.*

*Natural gas thermal, coal and hydro baseload plants have been retiring for two decades. The first wave of retirements began in the early 2000s well before significant renewables development began. It occurred primarily within the merchant generation fleet after new gas plant construction across much of the nation produced new, low-cost electricity at prices well below the cost capabilities of the older, smaller fossil plants that independent power producers bought from vertically integrated utilities during the early stages of wholesale market restructuring.*

## 4.2 Essential reliability services and baseload power plants

[UNDER CONSTRUCTION]

NERC on essential reliability services

EPSA sources on essential reliability services

PJM analysis on portfolio building

Sandia paper on grid reliability

RAP paper on capability reserves

NERC IVGTF and recent LTRA assessments

Need to balance reliability and resiliency against societal costs and societal preferences (all the state and customer requirements detailed above)

Cautionary illustrations from Hawaii, Germany, maybe Australia for what happens if you bring on too much VRE w/o adequate analysis, planning

Related questions & topics

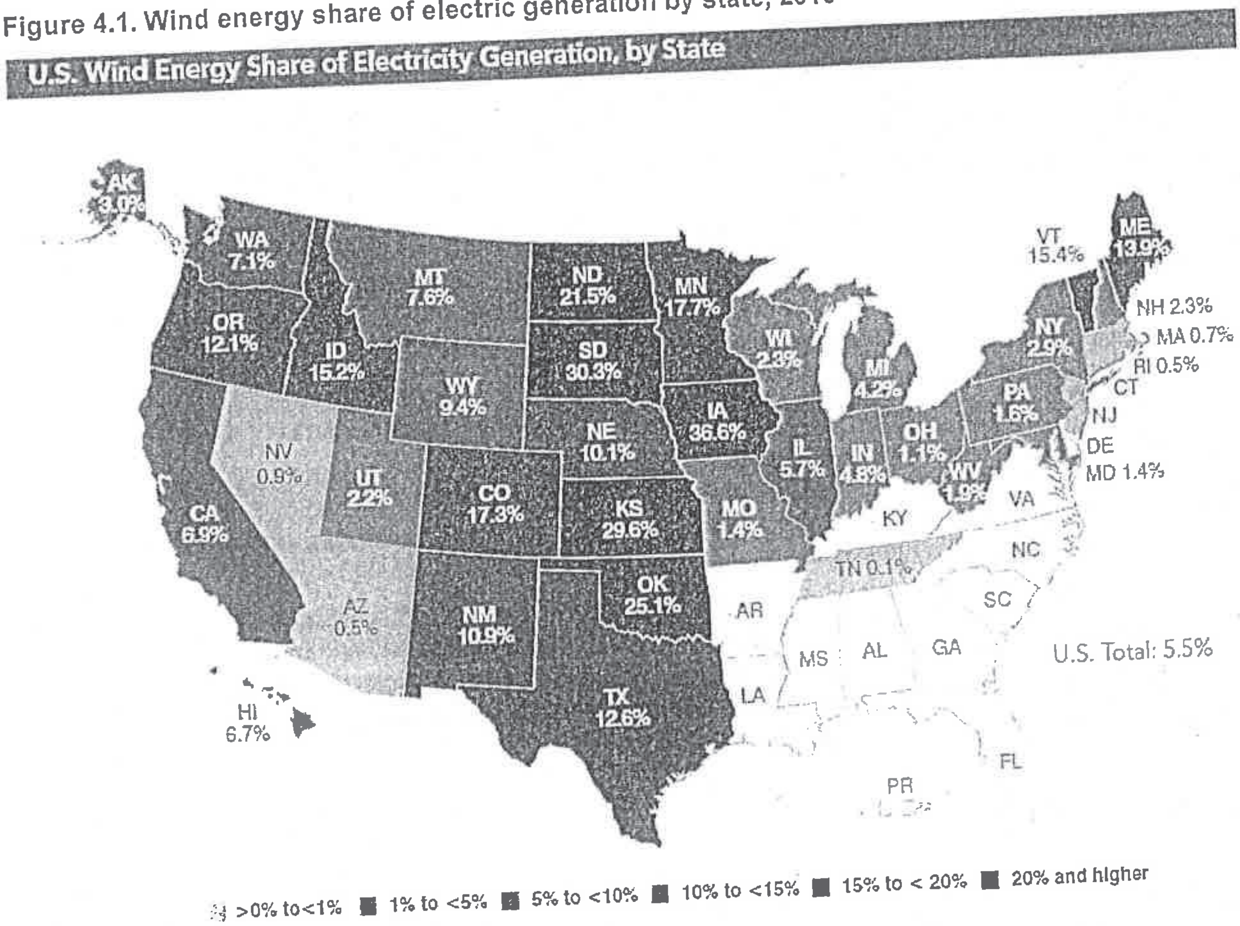
- Impacts of VRE on the grid
- Is there a minimum level of rotating mass needed on the grid? [needs more study]
- Role of customer load in providing inertia
- Is synthetic inertia from wind plants equivalent to large turbine generation (and how is it not)?
- Using DR and EE to modify customer side instead of putting all the burden of system balancing on supply-side resources
- Role of modern grid technologies to manage the system (both demand and supply sides) better

## 4.3 Effects of high levels of renewable penetration on the grid

[UNDER CONSTRUCTION]

Current levels of electricity production from wind are increasing rapidly (see Figure 4.1).

**Figure 4.1. Wind energy share of electric generation by state, 2016**[108]



## Potential Grid Integration Challenges

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).

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 variable RE to participate as dispatchable

Competitive Renewable Energy Zones (CREZ) in Texas are an example of an approach to quickly develop generation and transmission in coordination (18.5 GW wind and 3,600 miles completed nine years after CREZ legislation was signed), to access wind resources in remote parts of the state.

Grids are evolving in response to technological advances and anticipation of high RE 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).

Capacity payments or markets, potentially tied to flexible performance, could ensure sufficient cost recovery. The potential for stranded assets is not unique to variable RE, 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).

### Maintaining reliability with variable renewables

Legacy power plant owners are justified in questioning how high levels of variable renewable energy (VRE, wind and solar resources) could affect grid operations and the prospects for individual power plants. Figure x shows the most challenging week of operation modeled in the Western Wind & Solar Integration Study, Phase 1, which shows both huge displacement of legacy coal, nuclear and coal power plants by wind energy and dramatically different operational requirements (more cycling on and off and ramping up and down) for those plants.

**Figure 4.2. High VRE levels means big changes for conventional gas, coal and nuclear plants**[109]

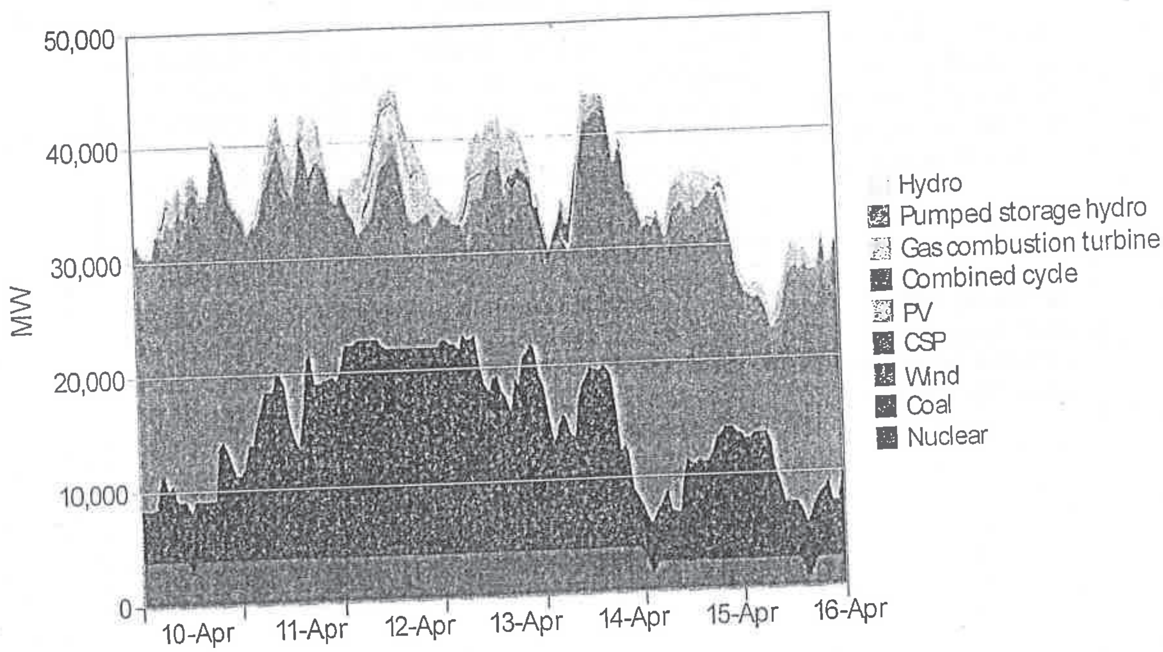



Figure ES-1. WWSIS-1 dispatch for the most challenging week of 3 years of data analyzed

Notes: PV, photovoltaic; CSP, concentrating solar power

One of the greatest challenges lies in how to manage the effects of fast-moving solar and load net of solar generation.

**Table 4.2. Characteristics of VRE power, grid integration challenges and mitigation options**[110]

| 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 variable RE 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 (CREZ) in Texas are an example of an approach to quickly develop generation and transmission in coordination (18.5 GW\| 3,600 miles completed nine years after |

| | | |
|---|---|---|
| | | CREZ 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[w] requirements are evolving in response to technological advances and anticipation of high RE 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 flexible performance, could ensure sufficient cost recovery. The potential for stranded assets is not unique to variable RE, 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). |

Balancing generation with electricity load requires more flexibility.

System operators could need additional reserves and/or an improved ability to dispatch generation.

More transmission and more advanced planning could be needed.

Numerous technical studies for most regions of the nation indicate that significantly higher levels of renewable energy can be integrated without any compromise of system reliability (Table 4.3).

**Table 4.3. Renewable energy penetration levels achievable by region, per recent technical studies**

| Region | Minimum level of renewable energy penetration (energy, not capacity) and technical source |
|---|---|
| New England | 24% |
| PJM | 30% |
| Midwest (MISO and SPP) | 25% |
| ERCOT | |

[w] Capacity payments or markets, potentially tied to flexible performance, could ensure sufficient cost recovery. The potential for stranded assets is not unique to variable RE, 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).

| | |
|---|---|
| California | 50% RPS – "Investigating a higher renewables portfolio standard in California," E3, ECCO International & DNV KEMA, January 2014 |
| Eastern US | 30% |
| Western US | 33% wind and solar energy penetration – "The Western Wind and Solar Integration Study Phase 2," NREL, Intertek-APTECH, GE Energy, September 2013<br>40% renewable penetration – "WECC Flexibility Assessment," NREL and E3, December 2015 |
| Hawaii | 100% RPS by 2045 – "Hawaiian Electric Company Power Supply Improvement Plan," E3 for Hawaiian Electric Company, December 2016 |
| National | 50% |

There are four principal ways to maintain and enhance bulk power system reliability: technology, rules and standards, business practices, and using high (and expensive) levels of transmission and generation.

## Using technology advances to provide essential reliability services

**Source: Jacquelin Cochran, Paul Denholm et al., National Renewable Energy Laboratory, April 2015**

Technology advancements now enable wind plants to provide the full spectrum of balancing services (synthetic inertial control, primary frequency control, and automatic generation control), an increasingly common requirement for systems with high levels of RE generation (Ela et al. 2014). For example, ERCOT requires wind turbines to provide an autonomous response to changes in power grid frequency, and the Colorado utility Xcel Energy requires many turbines to be on automatic generation control, which allows the computerized control system to directly control wind generation output (Bird, Cochran, and Wang 2014). PV plants are also starting to implement similar grid requirements (Morjaria et al. 2014).

Modern turbines and solar plants can also provide voltage support. Distributed solar PV systems can be configured with smart inverters that monitor local grid conditions and autonomously provide system grid services. The California Public Utility Commission, for example, is updating interconnection requirements for distributed PV to include smart inverters that provide local voltage support, meet ramp rate requirements after an outage, and ride through frequency and voltage events (CPUC 2014).

Revising grid codes early allows hardware and procurement agreements to be designed in advance of high variable RE penetration levels and reduces the financial burden associated with implementing such requirements retroactively. Germany's requirements for installed solar photovoltaic (PV) to provide grid services were applied retroactively, at considerable cost (Cochran et al. 2012).

FERC, NERC and the RTOs and ISOs have undertaken several initiatives to use rules, standards and grid codes to modify requirements for both interconnecting renewables and legacy power plants to improve grid reliability. These initiatives include early work to develop Low Voltage Ride-Through requirements for interconnecting wind and solar generation and NERC's recent Lessons Learned warning that …

The Bonneville Power Administration offers a good example of how to integrate wind energy effectively using operational and business practices rather than bringing on more reserves. Wind generation capacity in BPA's balancing authority area grew from 250 MW up to 4,782 MW in June 2016, driven by state RPS requirements and federal and state tax credits. Much of the wind generation is located along the Columbia River Gorge, connecting to the high voltage transmission system serving BPA's Columbia River hydroelectric plants, so the wind fleet had little output diversity and could swing output as much as 1,000 MW within an hour. BPA dealt with the reliability risk by limiting the amount of transmission capacity BPA would provide the wind fleet (establishing control and curtailment on wind production), began charging for using hydropower to balance the wind generation (also called a balancing capacity rate, since adopted by FERC for other regions), and setting a penalty rate to encourage accurate wind production scheduling. Wind forecasting and scheduling practices and tools have improved significantly since. As generation over-supply has created more hours when negative energy pricing occurs, BPA has worked with its stakeholders to create the Oversupply Management Protocol to assure that BPA can run its federal hydrogeneration when necessary to serve endangered fish and other obligations, compensating other generators for production curtailed to facilitate the federal hydropower.[111]

PJM on how markets advance reliability

Will high penetrations of renewables impact affordability? [Capture direct impacts on electricity prices as well as increased tax burden.]

**Utility Dive, "Los Angeles muni to join Western EIM in 2019," 6/2/17 and CAISO Western EIM Benefits Report, Fourth Quarter 2016.**

"Participating utilities balance their loads in real time, and the market has saved more than $170 million since launching in November 2014."

Matching demand with renewable megawatts is an important function of the market. The California ISO curtailed about 80,000 MWh in March—up from 47,000 MWh in the same month in 2016. However, a recent report concluded that the EIM is helping to minimize curtailments. Members have also saved $173 million since the wholesale market was launched in November 2014.

NERC graphic, Hawaii or CAISO or CEC graphics

## 4.4 Fuel diversity and resource portfolios

[UNDER CONSTRUCTION]

Hartman on diversity index

how has fuel diversity changed over the past 15 years? More or less diverse? Diversity is another aspect of how to deliver valuable reliability and resiliency services, not a goal in itself.

Looking ahead: Risks of a gas-heavy generation system, including common modes of failure. Ways to mitigate this through markets, rules, technology, operations?

EPSA work on diversity, including NERC resources and PJM paper & appendix

**Figure 4.3. Fuel Diversity**[x112]

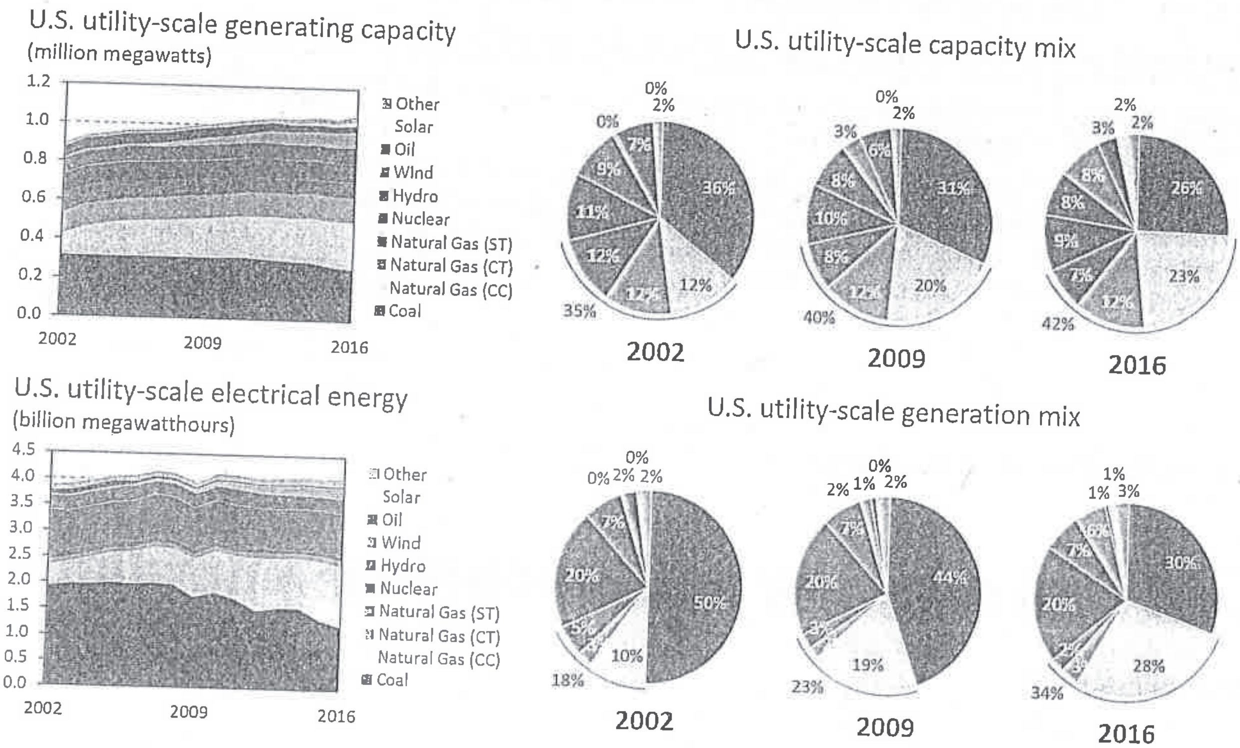



**Table 4.4. U.S. utility-scale generating capacity, 2002 vs. 2016**

**U.S. utility-scale generating capacity, 2002 vs. 2016**

| Technology | 2002 MW | 2002 Percent of Total | 2016 MW | 2016 Percent of Total |
|---|---|---|---|---|
| Coal | 315,655 | 36% | 270,058 | 26% |
| *Natural Gas (all)* | *313,277* | *35%* | *446,958* | *42%* |
| Natural Gas (CC) | 106,109 | 12% | 239,519 | 23% |
| Natural Gas (CT) | 104,170 | 12% | 131,012 | 12% |
| Natural Gas (ST) | 102,998 | 12% | 76,426 | 7% |
| Nuclear | 100,324 | 11% | 99,316 | 9% |
| Hydro | 79,356 | 9% | 79,985 | 8% |
| Wind | 4,417 | 0% | 81,312 | 8% |
| Oil | 59,651 | 7% | 36,398 | 3% |
| Solar | 397 | 0% | 21,528 | 2% |
| Other | 14,590 | 2% | 21,155 | 2% |
| **Total** | **887,666** | | **1,056,710** | |

[x] Notes: Natural gas technologies: ST = steam turbine, CT = combustion turbine, CC = combined cycle

ORNL paper

NERC and PJM

Has the diversity of the electric system diminished? If yes, is this a problem for baseload power?

No -- the electric system is more diverse today than it was 20 years ago. This diversity is a problem for baseload power, but it enhances bulk power system reliability and resilience rather than compromising it.

Relate diversity to performance and operational characteristics and what the BPS and electric wholesale markets should be valuing and compensating

Diversity and national security

Diversity alone does not guarantee reliability. Reliability is attained through the characteristics and capabilities of a portfolio of supply and demand-side resources that must be structured and incented to deliver reliability, not merely through the fact of diversity in itself.

**IHS – Makovich et al – "The Value of U.S. Power Supply Diversity," July 2014**

Engineering and economic analyses consistently show that an integration of different fuels and technologies produces the least-cost power production mix. Power production costs change because the input fuel costs— including for natural gas, oil, coal, and uranium—change over time. The inherent uncertainty around the future prices of these fuels translates into uncertainty regarding the cost to produce electricity, known as production cost risk. A diversified portfolio is the most cost-effective tool available to manage the inherent production cost risk involved in transforming primary energy fuels into electricity. In addition, a diverse power generation technology mix is essential to cost-effectively integrate intermittent renewable power resources into the power supply mix.

The current diversified portfolio of US power supply [in 2013] lowers the cost of generating electricity by more than $93 billion per year, and halves the potential variability of monthly power bills compared to a less diverse supply. Employing the diverse mix of fuels and technologies available today produces lower and less volatile power prices compared to a less diverse case with no meaningful contributions from coal and nuclear power and a smaller contribution from hydroelectric power.

... The shale gas revolution and restrictions on coal are driving an increased reliance on natural gas for power generation and provide strong economic benefits. However, this past winter demonstrated the danger of relying too heavily on any one fuel and that all fuels are subject to seasonal price fluctuations, price spikes, and deliverability and infrastructure constraints. The natural gas price spikes and deliverability challenges during the past winter were a jolt for a number of power systems that rely significantly on natural gas in the generation supply. These recent events demonstrated that natural gas deliverability remains a risk and natural gas prices continue to be hard to predict, prone to multiyear cycles, strongly seasonal, and capable of significant spikes. The root causes of these price dynamics are not going away anytime soon. The best available tool for managing uncertainty associated with any single fuel or technology is to maintain a diverse power supply portfolio.

... Maintaining and preserving a diverse US power supply mix is important to consumers for two reasons:

- Consumers reveal a strong preference for not paying more than they have to for reliable electricity.
- Consumers reveal preferences for some degree of predictability and stability in their monthly power bills.

## 4.5 Grid resiliency, fuel assurance and on-site fuel storage

[UNDER CONSTRUCTION]

Waiting for data on how coal and nuclear plants performed in actual emergency situations (polar vortex, Hurricane Sandy) – do they have black-start capability? Did they freeze up or remain operational? Has anything changed in their capabilities?

Performance of different types of generators during recent system emergencies (Hurricane Sandy, polar vortex, hurricanes) – what failed and why? Any lessons?

NERC on polar vortex, SW outage, other plant performance issues

FERC black-start rates

Again, regional issue, not national, given different failure modes (other than common cyber issue) affecting different types of prevailing resources

PJM evolving resource characteristics paper, Fig 6

EPRI report on flexibility

Need for flexibility on the grid – ERCOT example, where existing baseload and intermediate plants didn't meet the need – use utility dive story, not lab example.

## 4.6 Diversity, reliability and resource portfolios

[UNDER CONSTRUCTION]

EXPLAIN – whether wholesale energy and capacity markets are adequately compensating attributes such as on-site fuel supply and other factors that support grid resilience, and could this affect reliability and resilience in the future?

- Why capacity and energy products aren't enough
- Essential reliability services, ancillary service markets, and need to define new electricity products
- On-site fuel availability is only fuel assurance at a super-local, plant-specific level; role of this for system resilience. Whether plants with on-site fuel have actually proven resilient in recent system emergencies
- Fuel assurance and national security

NERC on essential reliability services, IVGTF findings

- Increased speed of supply variability from wind and solar ramps
- Illustration -- NYT, "Coal Country's Power Plants Turning away from Coal," 5/26/17

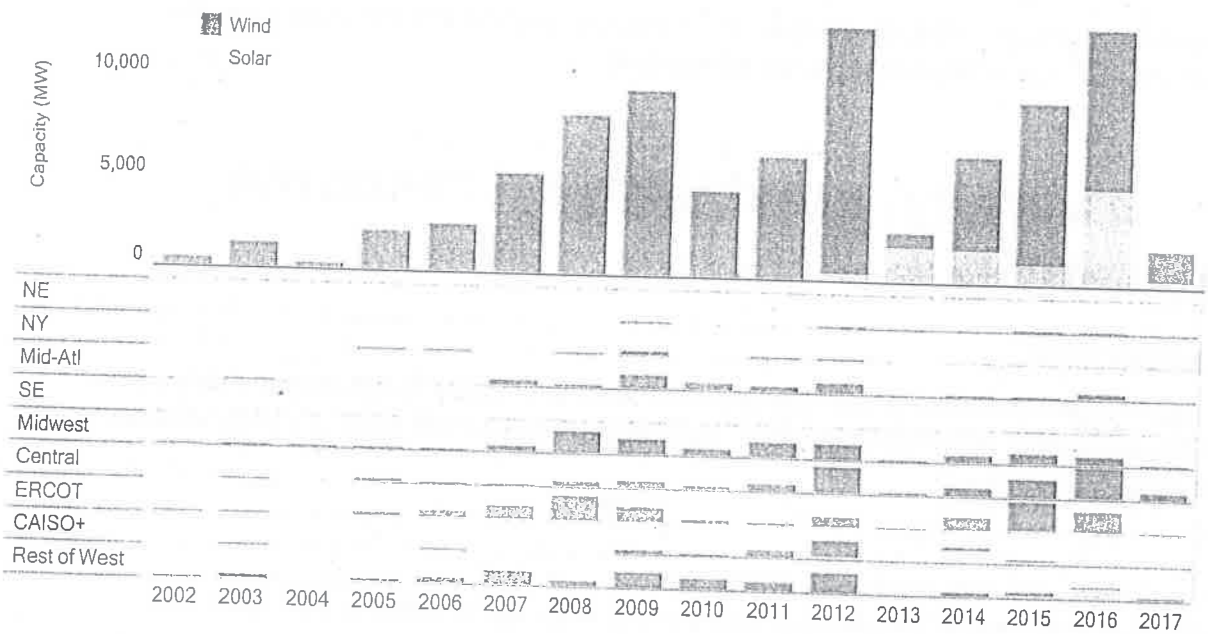
## 4.7 Reliability and resiliency – looking forward and next steps

[UNDER CONSTRUCTION]

# 5 Renewable energy growth, reliability impacts and prospects

[UNDER CONSTRUCTION]

**Figure 5.1: Annual Generation Capacity of Wind and Solar, Total and by Region, January 2002 through March 2017**[113]




## 5.1 Growth in renewable energy penetration

[UNDER CONSTRUCTION]

Incentives and subsidies

Growth patterns

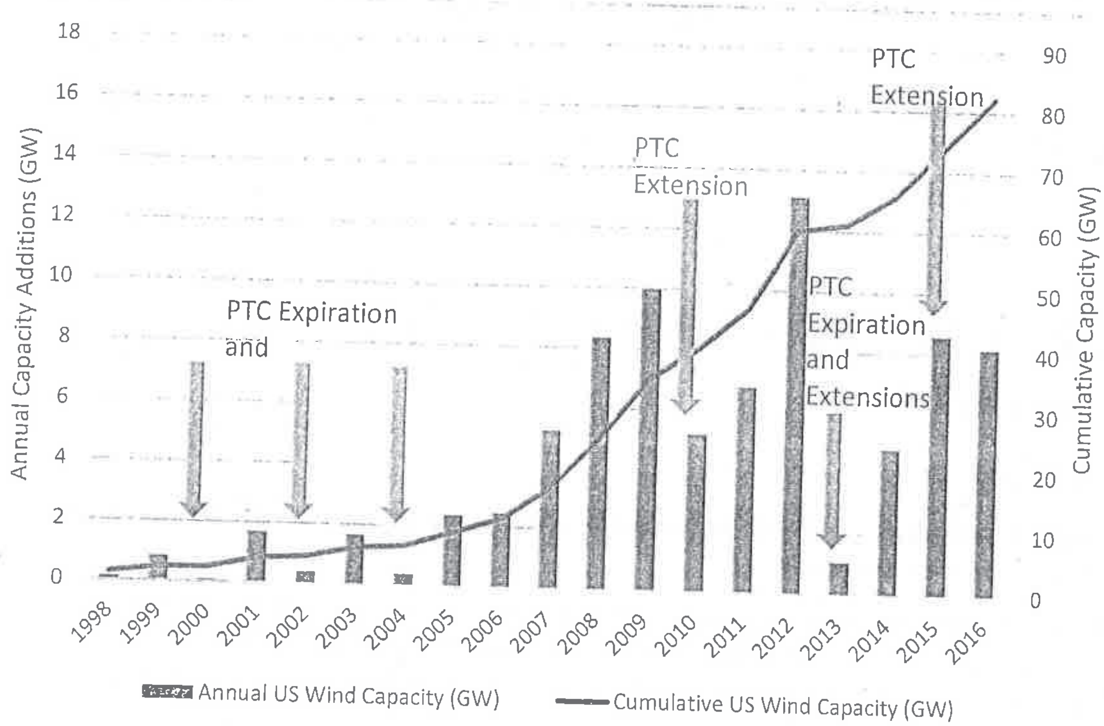
## 5.2 Impacts of renewable energy on grid operations

[UNDER CONSTRUCTION]

Duck curve

Moving the peak

**Figure 5.x – Federal tax policy has had a significant effect on wind capacity development (Source: Updated QER Figure 3-4. Relationship between the Production Tax Credit and Annual Wind Capacity Additions[115])**




State energy policies affecting at least two-thirds of the nation's electricity users have already made a long-term commitment to encourage renewable energy use. These state measures include establishing renewable portfolio standards (see Figure 5.x), establishing state subsidies (investment or production tax credits, setting up a renewable energy credit program to make renewable energy more fungible, or setting up greenhouse gas programs (emissions targets, carbon pricing and carbon credit trading) that favor low-emissions renewable generation. [DSIRE 2017, C2ES 2016]. Several states have policies to use public benefit funds for energy efficiency and renewable energy acquisitions. [C2ES, Public Benefit Funds]

Lower CF contribution

## 5.3 Integrating renewable energy to maintain reliability

[UNDER CONSTRUCTION]

LBNL, NERC IVGTF, etc

Ability of VREs to provide ERS

## 5.4 Renewable energy growth will continue

[UNDER CONSTRUCTION]

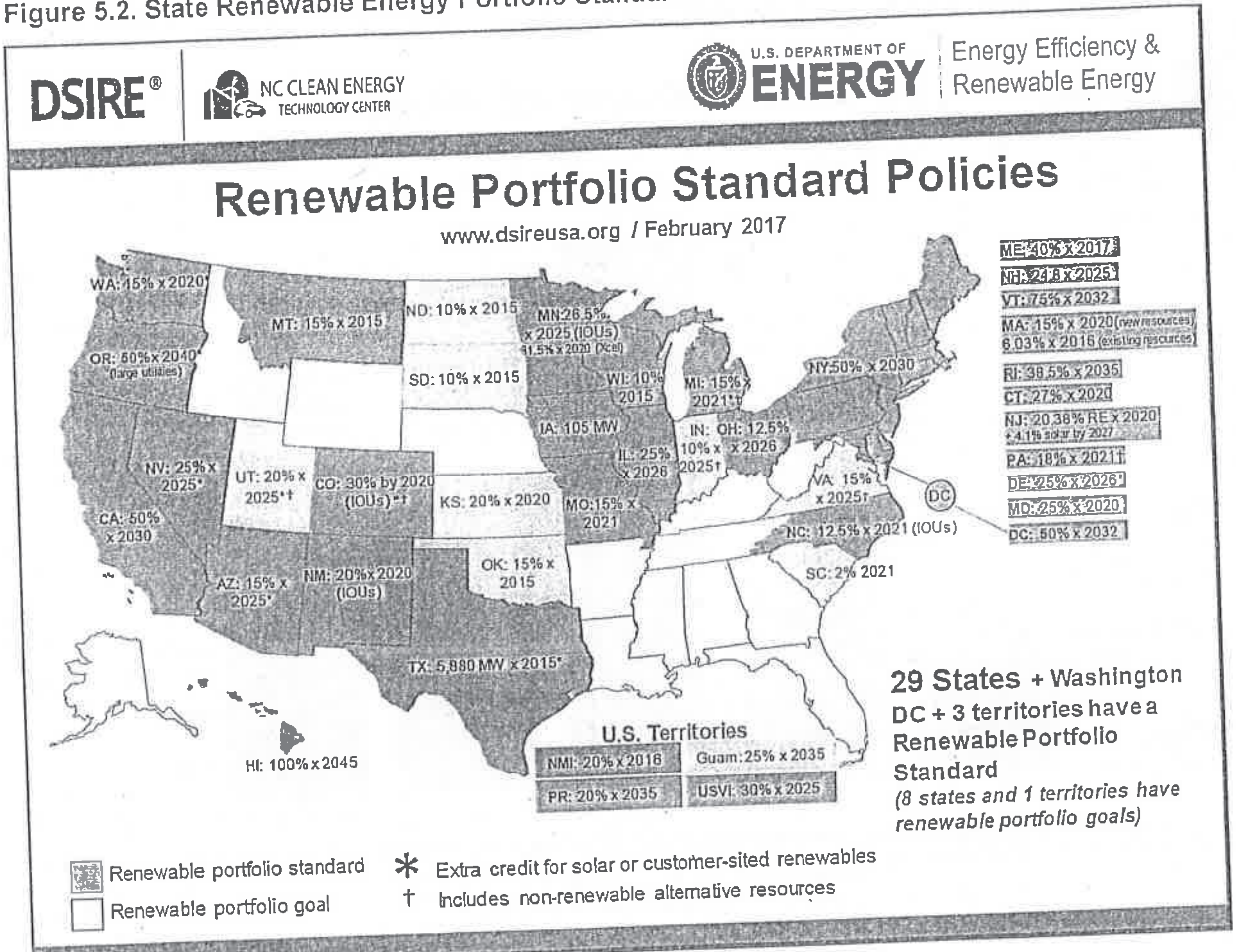
Will removing renewables subsidies and RPS make renewable generation go away (and presumably put less pressure on coal and nuclear plants)? No.

- Current federal PTC for wind ends soon, federal ITCs for solar PV and energy efficiency ended in ___. Forty percent of current wind capacity does not receive PTC. [Rob Gramlich]
- Cost and price forecasts for domestic and global nat gas and renewables production prices all show continuing long-term downward trends

QER: Declining costs for wind and solar have been spurred by industry innovation as well as a variety of Federal and state policies that accelerate deployment. Technology improvements in wind turbines—including taller turbines, longer blades, and advanced turbine designs — have enabled substantial cost reductions for wind power. Power purchase agreements for wind have fallen from rates as high as 7 cents/kWh in 2009 to around 2 cents/kWh inclusive of the Production Tax Credit (PTC) in 2015, driven by wind deployment in excellent resource locations in the interior regions of the country.[114] Regulatory policies accelerating wind development include the renewable energy tax credits at the Federal level and the renewable portfolio standards (RPSs) at the state level.

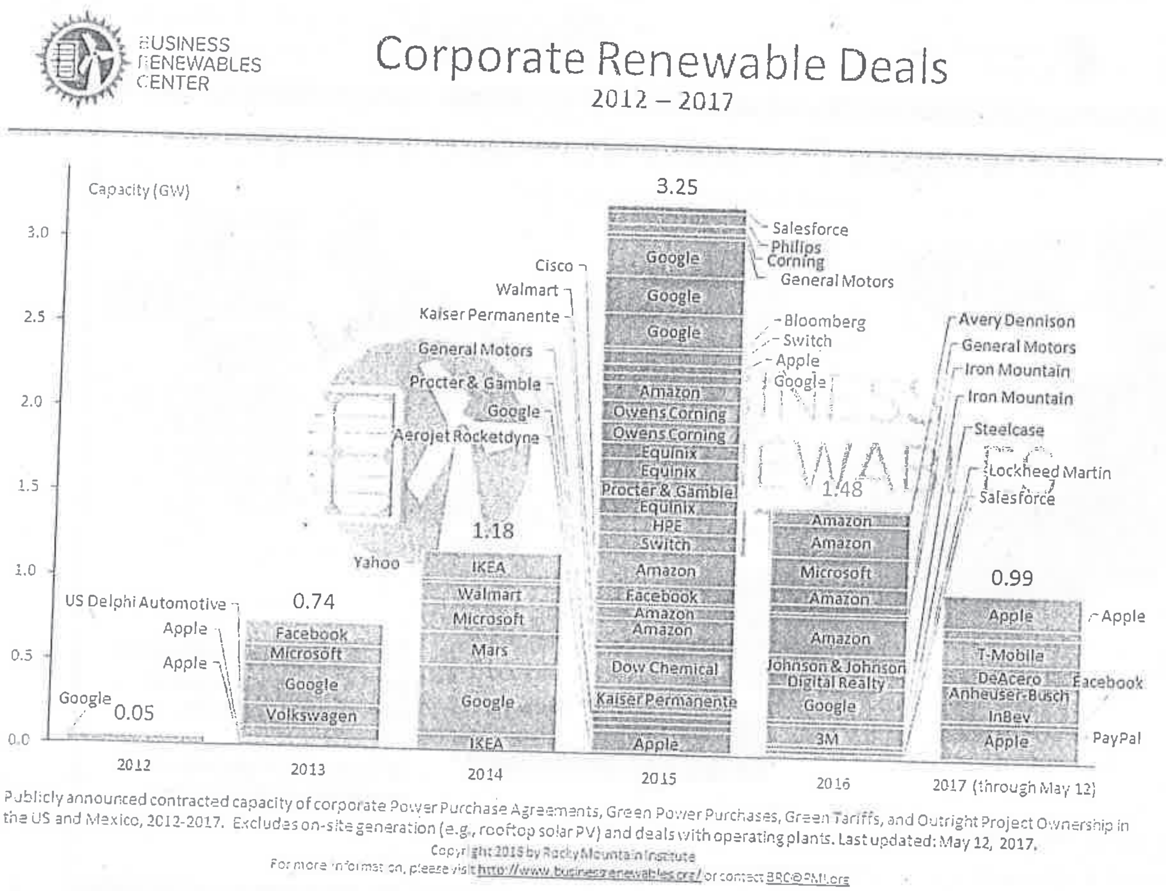
At the Federal level, the Investment Tax Credit (ITC) and PTC established under the Energy Policy Act of 1992 are two key Federal tax incentives that have been instrumental in accelerating the construction of renewable electricity projects. (See Figure 5.x) Both of these incentives are designed for use by entities that pay Federal taxes and are subject to strict treatment under both the Internal Revenue Code and generally accepted accounting principles. These attributes have major implications for who utilizes the incentives and how projects are developed. The federal Production Tax Credit (PTC), enacted first in ___, directly affected wind project deployment -- between 2000 and 2013, cumulative wind capacity grew from under 5 GW to over 60 GW, directly tracking the PTC expiration and extension schedule.

**Figure 5.2. State Renewable Energy Portfolio Standards**[116]




Some electricity customers have established a strong preference for renewable energy. Increasing numbers of businesses have made commitments to use renewable energy, either through direct investments in its production (as by Walmart, Amazon and Google) or by buying renewable energy through utility or third- party retail electric provider green tariffs or through direct contracts with renewables producers. [World Resources Institute 5/2017, WRI 2 5/17, Bloomberg New Energy Finance 10/25/16, Corporate Eco Forum & WWF, 10/16] (See Figure 5.x) As of late 2016, corporate purchases of power purchase agreements directly with renewable energy producers have been doubling every year since 2012, both to execute their sustainability commitments and by the benefits of reducing and stabilizing energy costs with predictable, flat renewable energy purchases.[117]

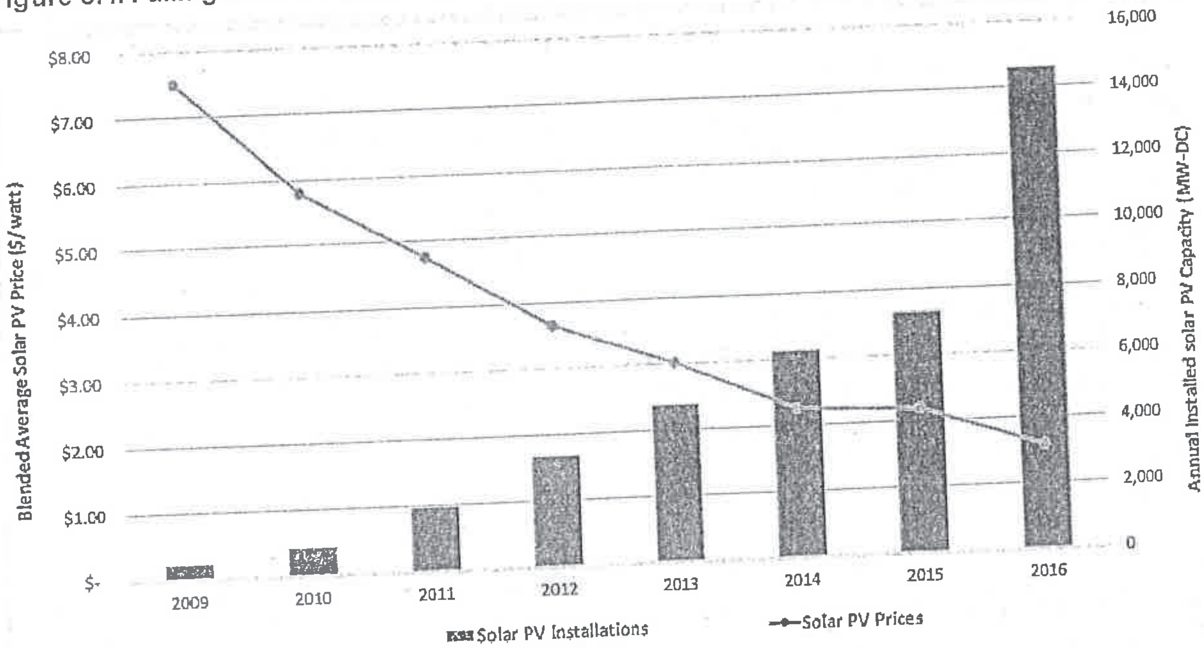
**Figure 5.3. Corporate purchases of renewable energy[118]**




At the residential level, x% of customers are buying renewable energy through some sort of green tariff and customer surveys indicate a strong preference for solar, wind and natural gas-fueled power. [SolarCity 3/15] And the number of customers installing solar photovoltaics is growing every year – at the end of 2016, there were --,000 residential rooftop PV installations representing –MW, with that growth rate increasing by --% every year as PV prices drop. [get these numbers and a good graphic from SEIA website]

Solar photovoltaics prices continue to fall (Figure 5.4), and therefore pose a continuing threat to the level of customer energy and peak usage available for supply-side generation to serve. The Solar Energy Industry Association reports that solar prices have dropped 67% since 2011, and that solar developers are now signing power purchase agreements for utility-scale plants at prices between $0.03 to $0.05 per kWh. [need someone to call SEIA to find out whether this is before or after ITC] Although PV generation is variable and subject to the availability of sunshine, these prices are so low that most power purchasers view PV at these rates as a valuable component of an electricity portfolio.

**Figure 5.4. Falling Solar PV prices and rising installed capacity[119]**




Utility-scale PV installed capacity is distributed unevenly across the United States. As Figure 5.5 shows, California comprises over 40 percent of the installed utility-scale PV capacity in the country, followed by North Carolina, and the Southwest of the United States with Arizona, Nevada, and Utah.

**Figure 5.5. Location of Utility-Scale Solar Generating Units, 2016[y]**


[y] Energy Information Administration (EIA), "Monthly Update to Annual Electric Generator Report," March 2017, https://www.eia.gov/electricity/data/eia860m/

Utilities are also restructuring their purchase patterns and resource portfolios to acquire or own much more renewable energy. At the June 2017 Edison Electric Industry conference, two utility CEOs explained their moves to increase renewables:

> DTE Energy CEO Gerry Anderson said his utility's move away from coal and toward cleaner sources of power was guided largely by economics. When the Michigan utility began preparing for the Clean Power Plan — an Obama-era emissions rule — officials found they "could deeply decarbonize DTE Energy and we could do it in a way that's affordable."
>
> That perspective is one shared by both the broader industry and PNM, said [Pat] Vincent-Collawn [incoming EEI Chair and PNM Resources CEO]. "If you look at where we are with natural gas prices, renewables prices, it's changed dramatically," she said. "So those market forces lead us to different conclusions because we do want to produce power at the lowest possible cost."[120]

Lazard Freres 2016 projections for continued downward prices for new utility-scale solar and wind capacity (use NREL instead?)

Illustration – Utility Dive, "Updated: Tucson Electric Power signs solar + storage PPA for 'less than 4.5c/kWh", 5/23/17 – competitive with peaker plant prices

## AEP, largest coal user in the East, sees cleaner energy demand

**Source: USA Today, interview with AEP CEO, 6/3/17**

Nick Akins, the CEO of American Electric Power, one of the largest utilities in the U.S., says the preference for gas, renewables and energy efficiency, will only grow in response to increasing demands from shareholders and customers for cleaner energy, regardless of changes in national energy policy.

With 5.4 million customers in 11 states, AEP plans to spend $1.5 billion on renewable energy from 2017 through 2019, and $13 billion on transmission and distribution improvements, including new "smart" technologies that will make the grid more resilient and efficient, AEP says.""

**"You don't see coal making a comeback at AEP or other utilities?** No, I don't think so. ... You wouldn't make a decision (to build a coal power plant) at this point because it's heavily capital-intensive, and involves a longer-term process and risk to build. And, of course, you can add renewables that are very efficient and natural gas that's efficient and much less expensive and risky, in terms of construction and operation.

**Do you plan to close any more coal-powered plants soon?** I suspect we'll see some more retirements in the future, and as we progress towards that cleaner energy economy, and consider the expectations of our customers and shareholders for us to mitigate risk, you'll continue to see that happen.

But on the other hand, I want to make sure there's an understanding that coal will remain a part of the portfolio, but it will be of a lesser degree because of these other resources that are available to us now that weren't available to us just a few years ago.

The availability of new transmission to interconnect utility-scale renewables to the grid has been essential for the accelerated development of VREs in resource-rich regions. Starting with Texas' example in the early 2000s, many states identified renewable energy development as an economic development and job creation opportunity, and encouraged grid planners and transmission utilities to build new transmission to open up those areas. FERC fostered this effort with the addition of wind-specific provisions for the Open Access Transmission Tariff [cite] in 2003 and the end to pancaked transmission rates in 200x. Several years later, FERC adopted Order 1000, requiring regional system planning and coordination, which facilitated development of more backbone transmission for increased trade and deliverability.

## Battery storage role

**Source: "Battery storage: The next disruptive technology in the power sector," David Frankel & Amy Wagner**, McKinsey & Co. blog, June -, 2017

Storage prices are dropping much faster than anyone expected, due to the growing market for consumer electronics and demand for electric vehicles (EVs). Major players in Asia, Europe, and the United States are all scaling up lithium-ion manufacturing to serve EV and other power applications. No surprise, then, that battery-pack costs are down to less than $230 per kilowatt-hour in 2016, compared with almost $1,000 per kilowatt-hour in 2010.

McKinsey research has found that storage is already economical for many commercial customers to reduce their peak consumption levels. At today's lower prices, storage is starting to play a broader role in energy markets, moving from niche uses such as grid balancing to broader ones such as replacing conventional power generators for reliability,[1] providing power-quality services, and supporting renewables integration.

Further, given regulatory changes to pare back incentives for solar in many markets, the idea of combining solar with storage to enable households to make and consume their own power on demand, instead of exporting power to the grid, is beginning to be an attractive opportunity for customers (sometimes referred to as partial grid defection). We believe these markets will continue to expand, creating a significant challenge for utilities faced with flat or declining customer demand. Eventually, combining solar with storage and a small electrical generator (known as full grid defection) will make economic sense—in a matter of years, not decades, for some customers in high-cost markets.

## 5.5 Reliability and resilience

[UNDER CONSTRUCTION]

*from QER:*

The reliability of the electricity system underpins virtually every sector of the modern U.S. economy. Reliability of the grid is a growing and essential component of national security. Standard definitions of reliability have focused on the frequency, duration, and extent of power outages. With the advent of more two-way flows of information and electricity, communication across the entire system from generation to end use, controllable loads, more variable generation, and new technologies such as storage and advanced meters, reliability needs are changing, and reliability definitions and metrics must evolve accordingly.

Increased computing power and more sophisticated telecommunication and metering equipment has pushed the time scale for balancing electric systems to shift from daily to hourly, minute to minute, second to second, or millisecond to millisecond at the distribution end of the supply chain, with events at the distribution level potentially affecting system frequency and transmission conditions. The demands of the modern electricity system have required, and will increasingly require, innovation in technologies (e.g., inverters), markets (e.g., capacity markets), and system operations (e.g., balancing authorities).

Electricity outages disproportionately stem from disruptions on the distribution system (over 90 percent of electric power interruptions), both in terms of the duration and frequency of outages; this is largely due to weather-related events. Damage to the transmission system, while infrequent, can result in more widespread major power outages that affect large numbers of customers with significant economic consequences.

The leading cause of power outages in the United States is extreme weather, including heat waves, blizzards, thunderstorms, and hurricanes. Events with severe consequences are becoming more frequent and intense, due to climate change, and have been the principal contributors to an observed increase in the frequency and duration of power outages in the United States.

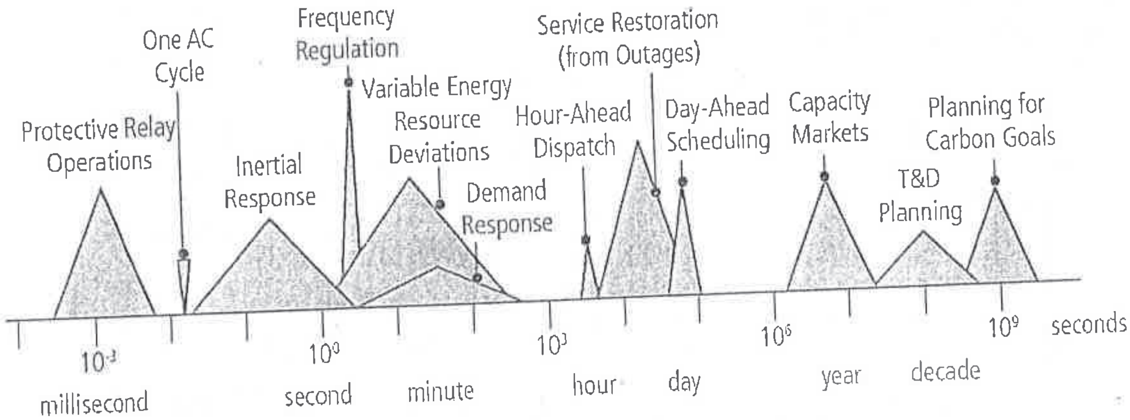
Grid owners and operators are required to manage risks from a broad and growing range of threats. These threats can impact almost any part of the grid (e.g., physical attacks), but some vary by geographic location and time of year. Near-term and long-term risk management is increasingly critical to the ongoing reliability of the electricity system.

Demand response (DR) technologies and programs offer a particularly flexible grid resource that is capable of improving system reliability, reducing the need for capital investments to meet peak demand, reducing electricity market prices, and improving the integration of variable renewable energy resources. DR can be used for load reduction, load shaping, and management of consumption to help grid operators mitigate the impact of variable and distributed generation on the T&D systems.

Maintaining power system reliability involves working to coordinate assets and ideas at multiple time scales, from long-term planning over decades down to operations occurring in real time at fractions of a second.

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

**Figure 5.6. System Reliability Depends on Managing Multiple Event Speeds**[121] ***Note, BCS to remove Planning for Carbon Goals***




Supply variability is an important part of system operations, where balancing authorities must ensure that risks of unexpected loss or variability of supplies are hedged by having some power plants immediately available (spinning reserves) and other plants able to supply power with short-term notifications of need (non-spinning reserves).

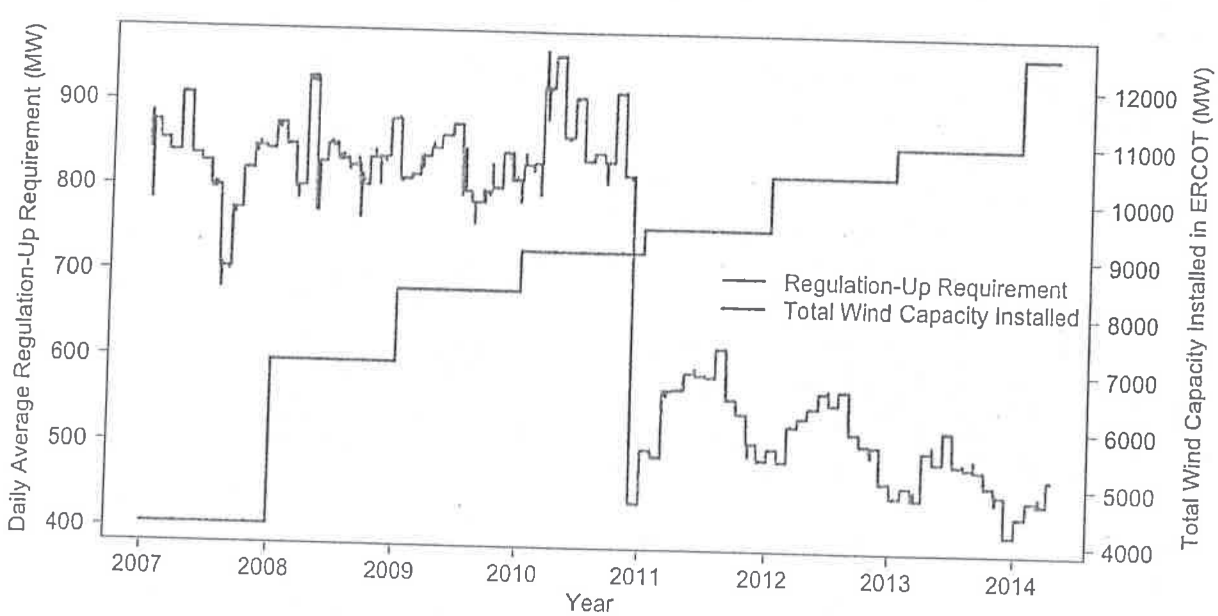
# 5.6 High levels of wind penetration can be integrated into the grid without harming reliability

[UNDER CONSTRUCTION]

Wind integration costs don't always go higher

Within ERCOT, as wind generating capacity grew from xx to xx MW and the share of energy rose from xx to y% per year, they have found that the amount of fast-acting frequency regulation reserve has fallen rather than grown, as shown in Figure 5.7. This is in part because ERCOT no longer has to provide contingency reserves to replace the sudden loss of the interconnection's largest generator (a nuclear power plant). Within ERCOT, contingency reserves cost about $0.76/monthly electric bill in the 2007 to 2011 period; after the ISO revised its contingency reserves to reflect the higher renewables penetration, the increased cost was only $0.04 cents/bill more.[122]

**Figure 5.7. Daily average regulation up requirement has fallen as wind capacity grows in ERCOT**[123]




Western Wind and Solar Integration Study Phase 3

- "With good system planning, sound engineering practices, and commercially available technologies, the Western Interconnection can withstand the crucial first minute after severe grid disturbances with high penetrations of wind and solar on the grid."
- "Adequate frequency response in the Western Interconnection was maintained for the conditions studied."
- "Selected nontraditional frequency-responsive controls on wind and solar power plants and energy storage were examined and could improve frequency response."
- "The transient stability of the system is not fundamentally changed by high wind and solar generation. This does not mean that the system behaves identically. There is, however, nothing to indicate that the system dynamics have changed so fundamentally that radically different means to ensure stability are required."

NREL Role of Wind Power in Primary Frequency Response (2016)

"The ability of wind power plants to provide PFR [primary frequency response]—and a combination of synthetic inertial response and PFR—significantly improved the frequency response performance of the system."

Powering into the Future: Renewables and Grid Reliability (MJ Bradley, 2017)

"Renewable generators also can provide frequency control. Many new wind and solar facilities have components called 'active power controls,' which allow their output to be increased or decreased to help maintain reliability. These controls allow renewable generators to provide primary frequency response that is similar to that of the automatic governors on conventional power plants. Using these components, they can quickly and automatically adjust their output to help stabilize grid frequency."

"These technologies can respond to automatic generation control signals every few seconds to rapidly increase or decrease output to help balance the system. They can also follow detailed, five-minute schedules that are shared with the central grid operator ahead of time, meaning that the dispatcher can count on a certain level of output on a short-term basis."

Powering into the Future: Renewables and Grid Reliability (MJ Bradley, 2017)

"MISO needed almost no additional fast-acting power reserves to back up 10,000-plus MW of wind power on the system."

"ERCOT needs only about 50 MW on average of fast-acting stand-by reserves to reliably integrate 10,000 MW of wind into the grid."

"PJM found that a 30 percent regional variable renewable penetration level— adding over 100,000 MW of renewable power—requires no additions in operating reserves, and only 1,500 MW (or 1.5 percent of renewable capacity) of quick-ramping regulation generators such as flexible natural gas generation."

"Large geographic size also helps to improve the collective capacity value of renewable generators (and reduces the need for other balancing services)."

Update to Analysis of Wind Generation Impact on ERCOT Ancillary Services Requirements (2013)

"Although additional regulation is necessary with increasing wind penetration, the main driver is still load variance rather than wind variance."

## 5.7 Reliability and resiliency – looking forward and next steps

[UNDER CONSTRUCTION]

# 6 Power markets

[UNDER CONSTRUCTION]

## 6.1 Wholesale Electricity Markets

This section has two subsections:

1) A review of the factors and events that have shaped the evolution of wholesale electricity markets; and
2) A discussion of the major issues in these markets today.

## 6.2 Evolution of U.S. Wholesale Electricity Markets

In the latter 1970s and '80s, the U.S. electricity industry was in a baseload capacity building boom. However, high inflation became particularly troublesome for utilities' high capital cost projects. Many large utilities were building nuclear plants, and all too frequently these projects became subject to major construction delays and cost overruns. Similar difficulties, although at a smaller scale, occurred at times with the construction of large new coal-fired plants. Many state officials, and eventually a majority of the U.S. Congress, concluded that if new generation capacity was needed in a given area, non-utility companies might well be able to provide that capacity at lower cost than investor-owned utilities, to the benefit of electricity consumers.

In 1978, Congress passed the Public Utilities Regulatory Policies Act (PURPA), which was an effort to curb the electricity industry's reliance on (at that time) high-cost natural gas and oil.[z] 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," as well as the development of new generation resources—specifically renewable energy and cogeneration facilities.[124] PURPA is significant because it introduced a form of competition to the investor-owned utility model and set the stage for later regulatory reform of the electricity industry.

The Energy Policy Act of 1992 included provisions authorizing FERC to approve "exempt wholesale generators," allowing any company, using any fuel and any generation technology, to go into the generation business and sell electricity at competitive prices. The act also gave FERC the authority under section 722 to order transmission owners to provide transmission service as required by transmission customers.

[z] 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 powerplant; and (2) construction of any new electric powerplant without the capability to use coal or any alternate fuel as a primary energy source." Source: https://www.congress.gov/bill/95th-congress/house-bill/5146 PPIFUA was repealed in 1987, which "set the stage for a dramatic increase in the use of natural gas for electric generation and industrial processing." Source: https://www.eia.gov/oil_gas/natural_gas/analysis_publications/ngmajorleg/repeal.html

In 1996, FERC used this transmission authority to mandate that public utilities[aa] provide open access transmission to the interstate transmission grid, through its landmark Order No. 888. FERC required public utilities under its jurisdiction to make non-discriminatory transmission service available to all parties, meaning charging all parties the same rate that the public utility would charge itself for the use of its transmission facilities. 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.

Electricity restructuring took hold in both the wholesale and retail sectors. It "allowed both non-utility generators to sell electricity to utilities – displacing the utility generation function – and/or "retail service providers" to buy electricity from generators and sell to end-use customers – displacing the utility procurement and billing functions."[125bb] Between 1998 and 2006, 23 states sought to bolster competition among bulk power suppliers by requiring their vertically integrated investor-owned electric utilities to divest some or all of their generating assets. Divestiture was pursued most aggressively by the states with high retail electricity prices (most of New England, New York, the Mid-Atlantic states, and California).[cc] Generating units that had been operating under cost-of-service regulation were sold to independent power producers (IPPs) or transferred to non-regulated investor-owned utility affiliates.

However, the wave of restructuring did not sweep over the entire nation. In large areas—particularly the Southeastern states and the West apart from California—the industry still consists of vertically-integrated utilities under cost-of-service regulation by state commissions or local regulatory bodies.[dd] As a result, two broad organizational structures exist at the wholesale level in the U.S. today:

- Traditional or bilateral markets -- These feature regional bilateral trading, primarily between vertically integrated utilities and utilities with independent generators. The Southeastern states and the non-California West do not have organized markets and so trade principally through bilateral contracts. However, many utilities in Western states already participate in—or plan to join—the Energy Imbalance Market (EIM) set up by the California Independent System Operator (CAISO).[ee126] Within the organized market areas, a large amount of the energy traded moves under bilateral contracts and self-supply, with these arrangements often benchmarked to organized market prices. And
- Organized or centralized markets -- These feature regional and multilateral bid-based optimization. Organized markets run by the independent system operators (ISOs) and regional transmission organizations (RTOs) are located in New England, New York, the Mid-Atlantic

[aa] The Federal Power Act defines a "public utility" as "[utility definition (non-ERCOT lower 48 IOUs and coops with no RUS debt.]. For example, non-ERCOT investor-owned utilities are "public utilities" under the FPA. Somewhat confusingly, publicly-owned electric utilities such as municipally-owned entities, also called public power, are not "public utilities" under the FPA.

[bb] Because the bulk power system is the focus of this report, we do not address retail restructuring in detail

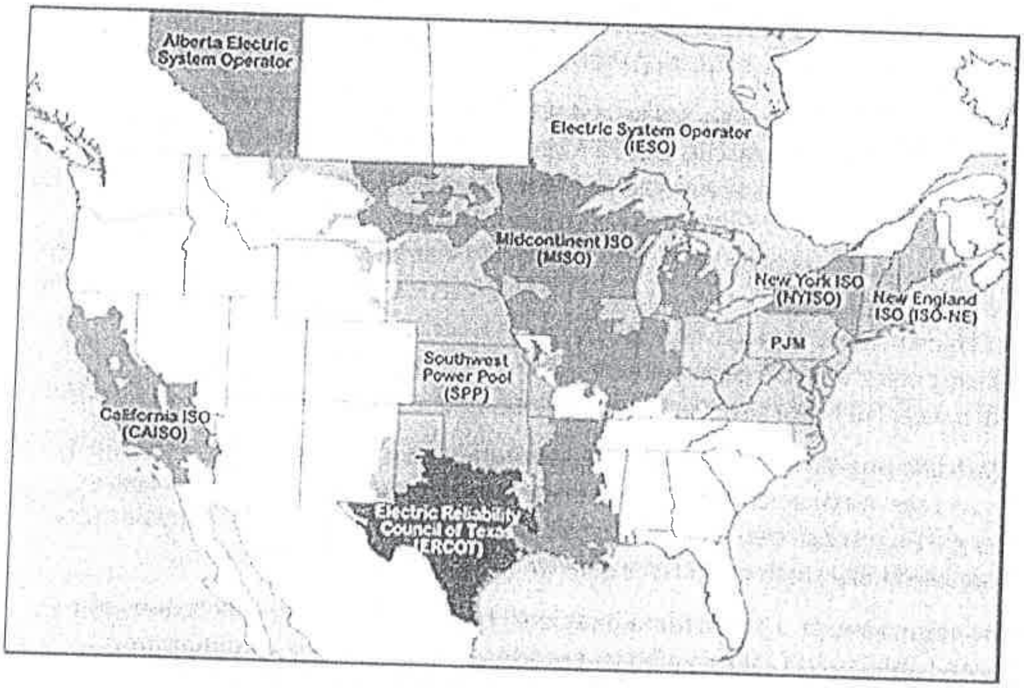
[cc] In most of these states, there was strong interest in making both wholesale and retail electricity markets competitive as a way to bring down high retail electricity rates, and 18 states embraced retail competition to some degree. California tried it and then retreated after lack of adequate infrastructure combined with major flaws in their market design led to blackouts and market abuse.

[dd] There also exist many publicly-owned utilities, the majority of which are not vertically-integrated, though some are. Cooperatively-owned utilities also exist, none of which are vertically-integrated. Both types are regulated by local elected or appointed governing boards, though a state public utility commission may have some jurisdiction in some states.

[ee] These utilities are not full members of CAISO but can participate in and benefit from its real-time wholesale energy market nonetheless. Notably, the EIM allows for greater flexibility in accommodating high levels of renewable energy integration.

states, parts of the Midwest and Southwest, California, and Texas. In these areas (Figure 6.1), the RTOs and ISOs perform short-term unit commitment and economic dispatch based on bids from suppliers and load-serving entities.[ff]

**Figure 6.1. The seven RTOs or ISOs in the U.S.**[127]



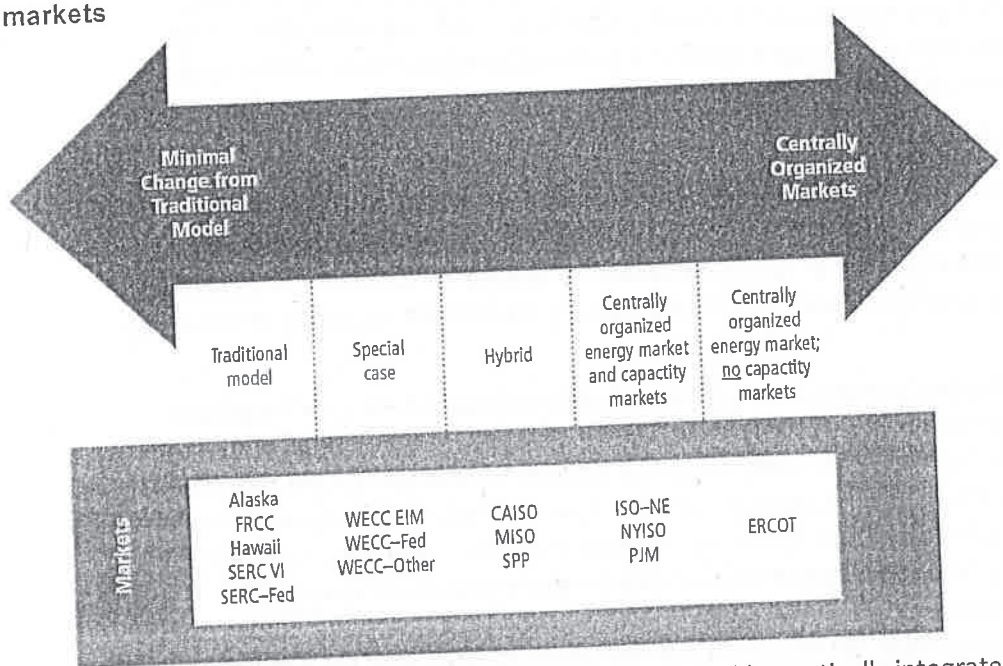

<u>Spectrum of Wholesale Power Markets</u>

It is useful to look at the spectrum of wholesale power markets through the perspective of where each market region stands along the path from fully vertically integrated electric utilities with minimal market organization to fully restructured, using an extensive centralized wholesale market for pricing and dispatch. (Figure 6.2) Other issues include the degree of centralized planning and mechanisms for resource adequacy, as well as the degree of retail competition in a market. The two attributes of degree of restructuring and types of resource adequacy constructs used form a useful framework for analyzing market differences and underscore the diversity of approaches to electricity policy amongst the states.

Bold up text in graphic, label what middle horizontal section's about. Replace "Hybrid" with, both vertically integrated utilities and centralized market. Fix graphic so it uses market region terms we don't have to explain Why would WECC Fed & WECC other be special cases? Move them under traditional with a * for Not state-regulated.

[ff] Although organized markets offer participants real-time and day-ahead markets for trading, a significant amount of energy traded even in these regions is under long-term contracts for purposes of price stability, hedging, etc. [would be nice to have an estimate here of the percentage, but I understand we don't have a good figure on this. Is that true? So far, yes]

**Figure 6.2. States and regions along the spectrum from traditional to fully restructured electric markets**




**"Traditional" markets** such as the Southeast are dominated by vertically integrated IOUs that operate under a regulated cost-of-service model, serving customers in a defined franchise area. Public power and rural cooperative utilities also have a significant presence in some regions, and their utility asset ownership models can vary from vertically integrated to distribution-only. IPPs operate within these regions, but the majority of power is produced and delivered by the integrated utilities.

Power purchases between these various entities are generally limited to bilateral trades. These can be made to take advantage of price discrepancies or cover shortfalls in supply. These bilateral transactions represent a small portion of the total generation in traditional markets and are typically in the form of long-term power purchase agreements rather than short-term trades. For example, in 2015 FERC estimated that short-term trades, called spot transactions, in the Southeast region accounted for less than one percent of overall supply.[128]

**In centrally organized wholesale energy markets,** generators bid on a day-ahead basis the price they are willing to produce power at, based on an assessment of their operating costs, fuel costs and return expectations. The market and system operator (the local RTO or ISO) then pools these bids into a single supply curve or bid stack and determines a clearing price that matches supply to predicted demand, and congestion forecasts for the day or hour ahead. This yields a set of market-clearing prices for each hour and location or geographic/electrical zone in the region and market time horizon. Each generator that bid at or below that market clearing price in that time period will be paid that price for generation delivered in that period, even if their bid prices were significantly lower than the market price. Most of the markets maintain price caps that limit what can be charged in any particular hour, to stem potential market manipulation.

In ERCOT and New York, which moved to full retail and wholesale competition, state restructuring policy required the utilities to sell their power generation assets and keep only the "wires" component of the business. All non-nuclear generation assets were sold to IPPs which manage and build new generation based on expected market earnings. The IPP owners seek to sell power under bilateral contracts to utilities or other off-takers, such as industrial users, or if contracts aren't available, sell their power into daily and day-ahead wholesale energy markets.

**Hybrid centrally organized markets** (e.g. California ISO and the Southwest Power Pool) combine elements of centrally organized energy markets and traditional resource adequacy mechanisms. In fact, several of these markets had moved toward more of a pure restructured model before moving back to elements of the more traditional regulated approach.

## Mechanisms for Resource Adequacy

Resource adequacy is "the ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements." Planning for adequate investment in generation and transmission capacity to ensure resource adequacy is a critical component of ensuring a reliable electricity system.

Traditional, vertically integrated regions and some utilities in hybrid markets conduct an integrated resource planning process to plan for necessary transmission and capacity investments (both for new generation and demand response). Some centrally organized markets have implemented capacity markets as a mechanism for ensuring future resource adequacy. In these markets, the system operator conducts an auction process, and retail service providers procure resources (including generation, energy efficiency, demand response, and transmission-enabled imports resources) to meet the electricity demands of their customers. These markets can be mandatory (PJM Interconnection and ISO New England); voluntary, where utilities can choose to operate under an integrated resource planning process (Midcontinent ISO); or voluntary backstopped by a mandatory process (New York ISO). Other regions (California ISO and the Southwest Power Pool) have capacity obligations where market operators require utilities to procure necessary generation reserves, either through ownership or through contracts with third-party providers. California and other states have intervened to require utilities to build or subsidize specific power plants outside the competitive capacity market processes, using the rationale that the intervention is necessary to assure resource adequacy.

ERCOT uses an energy-only market and does not have formal requirements or markets for capacity. In this approach, market scarcity pricing (relatively high energy prices during high-demand periods reflecting the lack of ample additional resources), provides necessary financial incentives for investment in generation capacity.

All of the RTOs and ISOs perform five basic functions[gg] :

1) Real-time management (dispatch for secure operation) of the transmission system within its footprint;

2) Ensuring non-discriminatory access to the area's transmission system by wholesale buyers and sellers;

3) Dispatch of generation assets in its footprint to keep supply and demand in balance, and to operate the generation fleet as economically as possible while observing security constraints;

4) Managing regional planning to meet future requirements for generation and transmission capacity; and

[gg] See https://www.e-education.psu.edu/eme801/node/535, p. 1, and PJM's Evolving Resource Mix and System Reliability, March 30, 2017, p. 16.

5) Coordinating provision of essential reliability services (ERSs) such as frequency response, voltage control, ramp capabilities, etc.

All of the market operators operate two markets for bulk electric energy to ensure that enough generation capacity will be on line to meet the energy demand expected over the next 24 hours. The "day-ahead" market determines, on the basis of resource bids, which generators will operate during each hour of the following day and at what level of output. In the "hour-ahead" or "real-time" market, the RTO makes any needed adjustments to resources' operating schedules to accommodate unexpected changes in demand or the availability of individual generation units.[hh]

Wholesale electricity prices in the RTO areas are "locational marginal prices" (LMPs) which reflect the value of electric energy at different locations, taking into account the shifting patterns of load, generation supply, and the physical limits of the transmission system (transmission "congestion").[ii] The LMPs are recalculated every five minutes to reflect changing market conditions. Generators and other resources (such as storage, demand response and out-of-region imports) are selected in merit order starting with the least-cost resource and then adding the next lowest-cost resource until supply meets demand. All generators designated to run at a given time are paid the uniform market-clearing price—the LMP at that moment—regardless of their respective bids, which often vary widely among different technology types as shown in Figure YY.

Figure YY: Representative supply stack and merit order with clearing price "LMP*

[add graph.]

RTOs and ISOs consistently deliver efficiency benefits and savings that far exceed their costs:[jj]

> For example, in 2015, MISO estimated its benefits at between $2.4 and $3.3 billion, compared to $267 million in costs.27 Such estimates likely understate benefits considerably, as they do not fully account for outages and extreme system conditions.28 Strong net benefits accrue in MISO as well as CAISO and SPP, despite being comprised predominantly of regulated utilities. Regulated utilities generally pass their organized market revenues and operating costs through to ratepayers, and their resource investments must be approved by state regulators to receive cost recovery. This removes the incentive to follow market signals, closely manage risk and costs, and to innovate.
>
> Favorable value propositions have helped forge RTO/ISO expansion, as the trend of utilities joining RTO/ISOs has increased since the 2000s. In 2013, MISO integrated utilities spanning most of Arkansas, Louisiana, Mississippi and some of Texas. CAISO expanded outside of California in 2014, while SPP has also grown recently. A recent study of CAISO's full transformation into a multistate entity estimated the benefits to California ratepayers alone will be $55 million a year in 2020, escalating to $1 to $1.5 billion per year by 2030.

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[hh] https://www.e-education.psu.edu/eme801/node/535, p. 3.

[ii] See *https://www.iso-ne.com/participate/support/faq/lmp*.

[jj] Hartman: http://www.rstreet.org/wp-content/uploads/2016/08/67.pdf

[Further highlight benefits to consumers generally.]

The shift to "centralized" wholesale markets in the RTO/ISO regions has had far-reaching implications for the owners of generating capacity serving these regions. When divestiture occurred, the divested units lost the important cost recovery protections afforded by cost-of-service (COS) regulation. COS regulation sets up-side limits on the revenues an owner can receive, through administratively-determined rates designed to allow utilities to earn an authorized return on investment. However, COS regulation also provides high assurance that the variable and long-run fixed costs of a generating unit will be recovered (unless the utility was found to have acted imprudently, in which case associated costs may be disallowed).

The shift to competitive wholesale markets created major risks for the affected generation owners. The new financial arrangements put in place as part of the divestiture of nuclear and other generating units sometimes provided special cost recovery mechanisms for a limited period of time, particularly for units considered "stranded assets" that would have difficulty succeeding in a competitive market. Many of the newly independent generating units, including coal and nuclear plants, were highly profitable for a time in the new competitive markets (particularly those which were receiving a stranded cost recovery subsidy for their capital costs, which meant they could succeed by recovering only marginal costs). Between 2005 and 2008, variable renewable generation had barely begun to penetrate the bulk power system, and national natural gas prices were over $8 per MMBtu, helping to drive LMPs to high levels and obscuring the fact that ISO/RTO markets were not designed to guarantee cost recovery.

"Missing Money," Reliability Standards, and Capacity Market Formation

In the mid-2000s, the inability of many generation owners to recover sufficient fixed costs through the RTOs' energy-only markets became known as the "missing money problem." One of the earliest uses of the term "missing money" in the power generation business, primarily in the merchant-owned sector, was in 2005,[kk] when it became clear that prices to merchant generators consistently fell below the average total cost of power supply.[ll]

Missing money is still a problem. Merchant plant owners have:

> ... 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 much sellers can make when supply is tight. Without that [extra] 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 [label] of missing money has been expanded to include the price impacts of subsidized or [state renewable portfolio standard] 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.[mm]

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[kk] William W. Hogan, Harvard University, "'Energy Only' Electricity Market Design for Resource Adequacy," September 23, 2005, https://www.hks.harvard.edu/hepg/Papers/Hogan_Energy_Only_092305.pdf

[ll] Makovich, Martin, and Marks, p. 4, "Missing Money in Competitive Power Generator Cash Flows," IHS Energy, November 2014.

[mm] Severin Borenstein, "Electricity Markets and Missing Money", blog post, The Energy Collective, April 4, 2017, http://www.theenergycollective.com/severinborenstein/2401671/electricity-markets-missing-money.

Due to the "missing money" issue, merchant generation owners, particularly in the eastern centrally-organized markets, saw the problem as a threat to the economic viability of their investments in existing generating capacity as well as a barrier to the financing of new generation. The RTO/ISOs were concerned about resource adequacy and the need to ensure that generators would invest in upgrades of existing plants or in new plants when needed to assure reliability. They acted on these concerns to create pseudo-markets for electric capacity, using a forecast of future demand that assumes customers' willingness to pay for electric reliability in a way that closely parallels a vertically integrated utility world's assumed reliability reserve requirement.

Capacity markets operate in parallel with energy-only markets. The basic premise of a capacity market is that an owner of generating capacity or a demand-side resource should be compensated for making a commitment that it will build or maintain a given amount of capacity available in a specific location for a specified future period as a source of reliable wholesale electricity, regardless of the extent to which that capacity is tapped to serve the energy-only market. Four RTO/ISOs operate capacity markets,[nn] using annual auctions in which bidders compete by submitting offers (in terms of $/MWh) at which they are prepared to make capacity commitments. PJM and ISO-NE hold mandatory annual capacity auctions for three-year advance commitments; NYISO (mandatory in some zones) and MISO's hold annual voluntary capacity auctions for one-year commitments.

Capacity markets are very controversial. Some analysts assert that the missing money problem results largely from the unwillingness of regulators and the RTO managers to allow real-time energy prices to rise to their natural levels in periods when generation capacity is in short supply, because regulators don't want to expose retail customers to the risk of extreme price spikes. Scarcity pricing advocates believe that without scarcity pricing, the energy market is inefficient and that inefficiency creates the need for the capacity market.[oo] Scarcity pricing is needed, in this view, to allow owners of existing capacity to recover their fixed costs, and to provide signals to resource providers when it would be economically rational to invest in additional capacity. ERCOT, for example, considered but rejected creation of a capacity market; instead, its real-time energy prices are allowed to rise to a limit of $9,000/MWh, as compared to price caps in PJM and ISO-NE of $2,000/MWh. Critics argue that formal capacity markets are an inadequate substitute for scarcity pricing because they are administrative constructs with predetermined capacity demand curves and short time horizons.

The PJM and ISO-NE capacity markets have also been attacked by state regulators and consumer groups as expensive handouts to existing generation owners – that is, they have not led to the construction of new capacity in areas that are generation-short, nor to desired performance in times of system stress.

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[nn] ERCOT has recently modified its energy prices to include a "real time reserve price" adder, linked to an administratively-determined "operating reserve demand curve" (ORDC). Arguably, this amounts to building an explicit capacity component into its energy market, making ERCOT's resource adequacy approach similar to that of PJM and ISO-NE.

[oo] William W. Hogan, Harvard University, oral remarks, p. 454, transcript of FERC Technical Conference to Discuss 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) (Washington, DC, May 1-2, 2017), https://www.ferc.gov/CalendarFiles/20170530122053-Transcript,%20May%202,%202017.pdf

And these capacity markets do not incorporate necessary non-market considerations that matter to state policy-makers.[pp, qq]

> ..a shift towards more merchant generation and reliance solely on market revenues may *indicate a movement away from planning and policy decisions that take into account critical factors such as fuel diversity, environmental policies, and economic development[emphasis added]*. This is not a desirable trend nor is it an indicator of successful markets.[rr]

The variety of problems that arose during the "polar vortex" severe cold-weather events in January 2014 (e.g., frozen coal piles, equipment malfunctions, and the unavailability of significant amounts of generation capacity due to gas-delivery curtailments)[ss] caused PJM and ISO-NE to amend their capacity markets by establishing strong penalties for non-performance by generators that are receiving capacity payments.

Capacity markets as a market method for achieving resource adequacy remain works in progress. After several years of experience, merchant and now VIEU generators are not earning enough income from market-based energy and capacity revenues to consistently cover their average production costs, much less recover capital investment and profits. RTO/ISOs, regulators, market participants and others continue to debate new ideas for both improving the functionality of the markets and producing additional revenues for the generation owners. Note, for example, the recent attention given to using the capacity markets as mechanisms for procuring and ensuring the delivery of "essential reliability services" (ERSs), such as the provision of voltage support, frequency response, and ramp capability.[tt] ADD A DIRECT QUOTE TO BACK THIS LAST STATEMENT UP

# 6.3 Challenges in Today's Electricity Markets

[UNDER CONSTRUCTION]

In more recent years, the economic challenges faced by many existing generation units – especially in restructured areas and to a lesser extent in cost-of-service areas – have become much more apparent for several reasons, including:

1) Lower demand than expected. Electricity demand growth has stalled due to the economic downturn, increased efficiency in household and business use, as well as growth in self-generation from distributed resources.

2) Increased nuclear costs. The nuclear accident at Fukushima in 2011 – induced by earthquakes and tsunamis, not operational errors – revealed that an inability to deliver the power needed

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[pp] See written statements and oral discussion of state regulators at FERC May 1-2, 2017 Technical Conference.

[qq] American Public Power Association, various documents at Electric Markets, http://www.publicpower.org/Programs/interiordetail2col.cfm?ItemNumber=38695&navItemNumber=38586.

[rr] Caplan, Elise, Is increase in merchant generation capacity a positive?, blog, American Public Power Association, February 2017, http://blog.publicpower.org/sme/?p=1179

[ss] See *Polar Vortex Review*, NERC, September 2014.

[tt] FERC, May 1-2 Technical Conference, op cit

onsite for effective reactor cooling could have devastating impacts. This has led to the stationing of additional backup equipment and other precautionary measures at many U.S. nuclear plants, thus increasing their costs.[uu]

3) Increased coal costs. Owners of coal-fired plants have had to either make major investments at many plants or retire them in order to comply with new environmental requirements such as those initially set forth in 2011 by EPA in its Mercury and Air Toxics (MATS) rule.

4) Inexpensive natural gas. New technology for the development of shale gas resources has led to a major expansion in the availability of natural gas at very low prices. As a result, natural gas-fired plants now set the market-clearing prices during many hours in the RTO markets, and LMPs have drifted lower and lower.

5) Growth in wind and solar power. The wide adoption of state-level renewable portfolio standards (RPSs) created an administrative demand for wind, solar, and other renewable energy. In addition to the support provided by the RPSs, developers of wind and solar generation resources have been aided by two kinds of federal subsidies, a production tax credit (PTC) for wind generation[vv] and an investment tax credit (ITC) for solar. Further, over the last decade, the capacity costs for onshore wind and utility-scale solar have dropped by large percentages [to xx% of their costs in 2007]. The combined impact of favorable policies and falling costs has been rapid growth in wind and solar generation.

These economic challenges have driven many coal, nuclear, and even some gas-fired generation plants into retirement, and the economic viability of many baseload plants still operating appears questionable. The growth of wind and solar generation has contributed to erosion of the revenues earned by existing baseload plants because the owners of the wind and solar facilities are able to operate at near-zero variable cost. RTO/ISO energy markets dispatch units based on incremental operating costs. As a result, bidders with near-zero operating cost can under-bid those using other technologies. Wind and solar owners frequently offer *zero or negative bids*; these bids will almost always be accepted by the RTOs whenever these units are able to produce electricity. At the same time, because LMPs are being set in many hours by gas-fired plants, these owners know that they will probably earn enough overall to cover their relatively high fixed costs. Some wind generators are able to earn a return even when LMPs go negative, as long as the negative price is less than the per-MWh value of the PTC and other benefits.

PJM notes the effects of tax preferences on its market:

> Tax and subsidy policies have had an impact on the economics of certain types of generation. Specifically, the wind and solar production tax credits have had the most significant impact on nuclear generation. 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.[ww] Since

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[uu] See https://www.nei.org/Issues-Policy/Safety-and-Security/Fukushima-Response.

[vv] Wind developers had the option under the American Recovery and Reinvestment Act of 2009 to choose between a PTC and an equivalent ITC.

[ww] As a result of recent federal legislation, the production tax credit has been converted into a direct payment of cash option to reflect that the market for tax credits has been reduced in recent years.

> 2014, PJM has seen prices go negative at nuclear unit buses in approximately 2,176 hours representing 14.3% of all off-peak hours.[xx] (Source of the block quote is PJM's May 9th letter to the Secretary regarding his memo.)

Among the existing, unretired plants now serving baseload needs, nuclear units seem to have been hit especially hard in recent years. According to one recent analysis,[yy] 34 of the nation's 61 nuclear plants are losing money, and this group includes almost all of the remaining merchant nuclear capacity. The report says that these plants receive \$20-\$30/MWh for electricity that costs an average of \$35/MWh to produce, and are losing an estimated \$2.9 billion per year. Coal-based generation is also at risk. Possible changes in environmental regulations may slow but will not arrest this trend, absent a substantial increase in the price of natural gas and a reversal of trends across many states to increase their commitment to renewable energy.

The prospects of the loss of large amounts of nuclear capacity, the continued growth of gas-fired capacity, and environmental and employment concerns have caused a number of states to consider or adopt "out-of-market" measures, such as the laws recently enacted in New York and Illinois to grant "zero emission credits" (ZECs) to the owners of certain threatened nuclear units. Massachusetts has issued a solicitation for Canadian hydro and offshore wind as required by a new state law.[zz](Several other states are now considering similar legislation.) Owners of merchant non-nuclear baseload capacity have reacted strongly, arguing that subsidies aimed at specific large facilities amount to gross interventions in federally-regulated wholesale power markets, and that FERC should reject them summarily as being inconsistent with the "just and reasonable" requirements of the Federal Power Act.[aaa]

Some commenters have noted that "subsidies beget subsidies" and point out that if the ZECs approach is allowed to stand, many of the non-nuclear capacity owners who are also under heavy economic stress will seek relief from all possible sources. The cumulative result, they continue, could be major damage to the credibility of the wholesale markets, higher capital costs for many new grid-related investments, and higher costs for consumers.

The recent trends in these markets have highlighted a condition that has long been characteristic of the electricity industry – that is, the dominant generation technologies have had high capital costs and low operating costs. According to one recent analysis (Gifford et al.[bbb]) this condition has been particularly problematic in the merchant generation sector, where it has induced periodic boom-bust cycles that have driven many merchant companies into bankruptcy. Now, they say, it is threatening to do so again. Recently the CEO of one merchant firm (NRG) announced that his firm had lost almost \$900 million in

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[xx] The Independent Market Monitor for PJM has outlined its own views on the harmful impact of subsidies. Its analysis can be found at http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2016/2016-som-pjm-sec1.pdf

[yy] "More Than Half of America's Nuclear Reactors Are Losing Money," Bloomberg New Energy Finance, June 2017. Note: The full BNEF report is available only to Bloomberg subscribers. A digest of the report has been published by Utility Dive, http://www.utilitydive.com/news/bnef-more-than-half-of-us-nuclear-plants-losing-money/445195/.

[zz] Citation to the state of Mass RFP website

[aaa] Get quotation from NRG's Silverstein from FERC May 2 transcript or written statement.

[bbb] Gifford, Raymond L., et al., "The Breakdown of the Merchant Generation Business Model," Power Research Group, June 2017.

2016, and added that "... the competitive power sector is in a period of unprecedented disruption. I believe the IPP model is now obsolete and unable to create value over the long term."[ccc]

Further, Gifford et al. argue that the problem goes beyond the viability of the existing merchant gas-fired units:

> ... the construction of a new merchant CCGT does not pencil out to cover fixed costs of these generators. Policy makers should pause when markets count on planned merchant generation that cannot recover their fixed costs under current market conditions. The stark economics facing these plants makes it seem that either these planned additions will not be able to attract the capital to be built, or that the developers are betting on sustained and significant increases in prices to attract capital. Policy makers, regulators and customers lose under either scenario.[ddd]

In contrast, the 2016 PJM Market Monitor's report paints a less ominous picture. It finds that RTO 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 and BGE zones but have not covered total costs in the western ComEd 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.[eee]

The MMU's 2016 report also says that sufficient net revenues are provided by capacity, energy and ancillary services markets to support new entry for CTs and CCGTs in some but not all PJM zones:

- In 2016, a new CT would have received sufficient net revenue to cover levelized total costs in 13 of the 20 zones. The zones in which a new CT would not have recovered levelized costs were western zones in which lower capacity prices were not offset by changes in energy net revenues.
- In 2016, a new CC would have received sufficient net revenue to cover levelized total costs in nine of the 20 zones and more than 90 percent of levelized total costs in an additional five zones.
- In 2016, a new [coal plant] would not have received sufficient net revenue to cover levelized total costs in any zone.

Results in the PJM footprint for new wind and solar resources in 2016 were heavily dependent on revenues from state renewable energy credits:

- In 2016, net revenues covered more than 33 percent of the annual levelized total costs of a new entrant wind installation in ComEd, 49 percent of the annual levelized total costs of a new

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[ccc] See "NRG CEO: Independent power producer model 'obsolete,'" *Utility Dive*, March 1, 2017, http://www.utilitydive.com/news/nrg-ceo-independent-power-producer-model-obsolete/437150/ .

[ddd] Gifford, p. 6.

[eee] *2016 State of the Market Report for PJM*, pages 279-280. "As part of the review of market performance, the MMU analyzed the net revenues earned by combustion turbine (CT), combined cycle (CC), coal plant (CF), diesel (DS), nuclear (NU), solar, and wind generating units."

entrant wind installation in PENELEC and 198 percent of the annual levelized total costs of a new entrant solar installation in PSEG. Renewable energy credits accounted for three percent of the total net revenue of a wind installation in ComEd and 37 percent of the total net revenue of a wind installation in PENELEC. Renewable energy credits accounted for 83 percent of the total net revenue of a solar installation in PSEG.

Similarly, the market monitor's levelized cost analyses indicate that revenues from PJM markets are sufficient to support most existing resources, but that substantial amounts of existing coal and CT capacity is at risk of retirement:

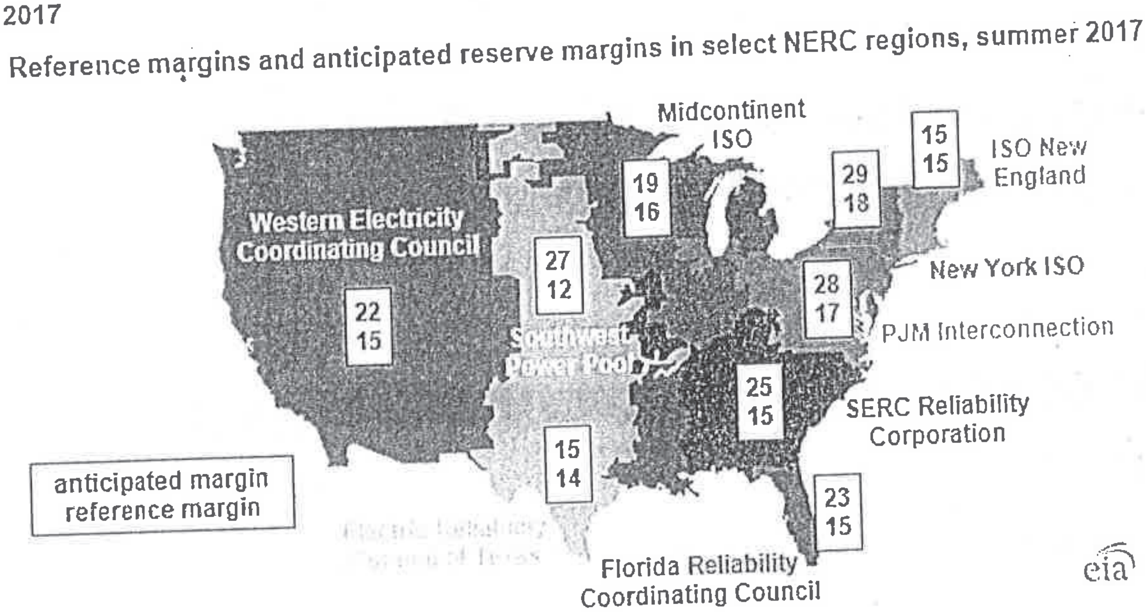
- In 2016, most units did not achieve full recovery of avoidable costs through net revenue from energy markets alone, illustrating the critical role of the PJM Capacity Market in providing incentives for continued operation and investment. In 2016, RPM capacity revenues were sufficient to cover the shortfall between energy revenues and avoidable costs for most units and technology types in PJM, with the exception of some coal units.
- The actual net revenue results show that 96 units with 14,500 MW of capacity in PJM are at risk of retirement in addition to the units that are currently planning to retire. Of the 96 units, 55 are CTs and account for 1,408 MW and 25 are coal units and account for 11,282 MW.[fff]

More generally,

Figure 6.3 below shows that capacity reserve margins in most of the nation's regions as defined by NERC are more than adequate to reliably serve load. A sustained pattern of additional retirements could significantly change this picture, but note: A wave of merchant bankruptcies, if it occurs, would not necessarily translate into a wave of plant retirements. A portion of the capacity owned by the bankrupt firms, particularly newer units, would presumably be sold to new owners at a discount, this reducing the buyers' fixed costs and better enabling them to operate the plants at a profit. Thus it appears that reliability *per se* may not be the problem ahead – rather, the greater concern may be to ensure that the portfolio of resources in each region remains a balanced portfolio with which to efficiently meet the range of public policy goals and customer expectations.

[fff] MMU report, p. xx.

**Figure 6.3. Reference margins and anticipated reserve margins in select NERC regions, summer 2017**




Source: U.S. Energy Information Administration, based on North American Electric Reliability Corporation, *2017 Summer Reliability Assessment*.

The end result is that there are pressures for major changes in the wholesale markets, particularly the three eastern RTOs and California, with generators seeking more predictable revenue streams from all sources (capacity, ancillary services and energy) with fewer interventions by the RTOs in those markets to adjust prices through bid mitigation and uplift charges. Recent discussions have centered on price formation in energy markets [cite Trade Association Principles and May 1-2 FERC transcript]. FERC has also undertaken a series of inquiries and rulemakings to .....

## 6.4 Negative pricing

[UNDER CONSTRUCTION]

Negative pricing from renewables harming baseload plants is not yet a huge issue

- In most areas and cases, there's a low % of time when negative bids occur, so they don't pose major loss burden on baseload plants (which need high average prices and high peak prices more than they need non-negative off-peak prices)
- baseload plants have bid negative to protect min load operation long before wind or PV drove over-generation
- in all hours when wind is doing "over-generation", hydro, coal and nuclear were hitting min load production, so it was their inflexible generation pattern that forced wind to bid negative
- many utility baseload plants do not bid into organized spot markets but are self-scheduled by VIEU, so they aren't taking MCP in hours when MCP <= $0.

LBNL paper

Wilson research with market monitors

logic

## 6.5 Market distortions, price formation and price suppression

[UNDER CONSTRUCTION]

Everything distorts markets

## 6.6 Markets – looking forward and next steps

[UNDER CONSTRUCTION]

# 7 Affordability

[UNDER CONSTRUCTION]

Secretary Perry's memo asks whether the loss of coal, natural gas, nuclear and hydroelectric baseload power making the grid less affordable. As discussed in Section 3, coal and nuclear power have become more costly while natural gas has become much less so. Wind and solar generation have high capital costs but their marginal cost is nearly zero (ignoring the value of the PTC). Efforts to retain many of the high-cost baseload plants that are now retiring may end up raising rather than lowering the average cost of wholesale electricity for many customers. It is not yet clear what impact all of the recent baseload plant retirements will have on customer bills, nor how the continuing trend of retirements will affect grid costs and bills.

Although many people have a sense of what the term "affordable" means, there is no formal metric for an "affordable" grid or an "affordable" electric bill. The meaning of "affordable" is often contextual, dependent upon the size of one's budget and how much one values the good sought – the perceived value of electricity is much lower to a comfortably housed family on a spring day than it is to a senior citizen living in a high-rise apartment in Chicago on an August afternoon.

There have been several studies of the impacts of RPS growth on regions of the country. A LBNL study summarizes those and concludes that the overall effect of a state-level RPS can affect customer rates from a decrease of 4% up to an increase of 1-2%.

One of the benefits of renewable energy is that it can serve as a hedge for more volatile fossil-fueled generation. Many customers seek a steady bill payment because it's easier to budget for and manage than bill that varies by month. To the degree that renewable energy stabilizes the cost of an overall energy portfolio (or even just a customer's bill), that affects perceived affordability.

## 7.1 Affordability -- Looking forward and next steps

- Develop a clear understanding of what electric affordability means
- Determine the costs of current power plant retirement levels
- Determine the impact of renewable energy on grid-connected customer bills.
- Determine the costs of likely on-going retirements for grid customers.

# 8 Values and extra-market considerations

[UNDER CONSTRUCTION]

Looking forward and next steps

## Coal power plant brings good jobs

**Source: "America's biggest greenhouse-gas polluter, and the place that relies on it," Elizabeth Hernandez & Eric Chaney, The Center for Public Integrity, June 5, 2017**

**https://www.publicintegrity.org/2017/06/05/20897/americas-biggest-greenhouse-gas-polluter-and-place-relies-it?utm_source=Sailthru&utm_medium=email&utm_campaign=Newsletter%20Weekly%20Roundup:%20Utility%20Dive%2006-10-2017&utm_term=Utility%20Dive%20Weekender**

The James H. Miller Electric Generating Plant ... is one of Alabama Power's coal-burning workhorses, putting out enough electricity to power about a million homes. It never stops running – and never stops producing carbon dioxide and other greenhouse gasses.

... Miller is a source of good-paying jobs, a means to raise a family in an area where economic opportunities are thin..... According to Alabama Power, salaries at the plant range from around $36,000 to about $120,000 a year, or about $74,000 on average. ...Miller employs around 365 people but can have as many as 1,500 contractors on site during planned maintenance outages. The plant pays about $12 million a year in property taxes.

# 9 Solution Options

There are a number of solutions that could be pursued to address the issues presented in this report. This section presents an extensive and varied list of possible solutions that is not exhaustive or ordered by priority but reflects the views of many stakeholders. This list of solutions does present options that are conflicting, which is necessary for a thorough catalogue. Inclusion in this list does not indicate an official U.S. Department of Energy position with respect to any of these solutions.

Below are some important core criteria that readers and decision-makers should consider when evaluating solution options:

1. *Reliability including Flexibility*: The system, including the customer, has sufficient capacity to balance generation with demand over operational, planning and investment timelines. The system has sufficient flexibility to match changes in next load over all operation time-scales, as well as changes in available generation due to outages.
2. *Resilience and Security*: The grid can survive and recover from disruptive events at sufficient speeds to prevent interruptions to critical services and minimize disruptions to the nation and its critical infrastructures.
3. *Affordability*: All customers have access to service at a reasonable cost, inclusive of all customer expenditures, enabling downstream job creation and growth of GDP. Service providers within the system receive revenues sufficient to incentivize adequate investment to meet reliability and resilience needs.
4. *Environmental Considerations and Public Health*: The costs associated with operations of the system reflect the existence and impacts of public health and environmental quality externalities, such as air pollution emissions, land use, and water quality.
5. *Competition:* Sufficient competitive conditions exist within the system, such as low barriers to entry, dispersed market power, and accurate and timely information, so that grid services and infrastructure can be obtained through market and non-market structures that support a variety of business models. These market structures properly balance short-run efficiency with long-term private and public sector investment, while fulfilling the criteria above.
6. *Innovation:* The entire system, including the grid, markets and institutions, is designed to welcome new technologies or practices that enhance the above criteria.
7. *Customer Options:* Customers, states, and other entities have the ability to obtain desired attributes not included in the criteria above.

| # | Solution Option |
|---|---|
| **1.** | Facilitate flexible energy storage projects across the grid.<br>• Allow long-term contracts for energy storage services.<br>• Allow storage to be compensated for all the reliability services it provides.<br>• Remove restrictive storage regulatory asset classifications.<br>• Enable distribution-level power reliability through power electronics, smart inverters, and integrated building controls.<br>• Pursue R&D on flexible energy solutions and corresponding power electronics capabilities |

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| 2. | Allow power plants to improve efficiency and reliability without triggering new regulatory approvals.<br>• Implement R&D portfolio targeting efficiency improvements across the generation fleet<br>• Provide regulatory certainty for units who wish to reduce fuel consumption or improve performance<br>• Accelerate improved efficiency of transmission and distribution system to improve reliability and affordability. |
| 3. | Accelerate investment and deployment in power systems to address reliability and affordability concerns through:<br>• Streamlining transmission investment and deployment process to reduce generation and transmission constraints<br>• reforming energy infrastructure siting and permitting to expedite development<br>• Updating transmission backstop siting authority<br>• Simplifying loan guarantees for large scale energy projects<br>• Modifying resource adequacy standards to have a longer time horizon |
| 4. | Accelerate licensing and relicensing and reduce costs of nuclear, hydro, geothermal, and new generation technologies. |
| 5. | Acknowledge state energy generation policy preferences in federal and regional rates and pricing decisions.<br>• Research and encourage ways to implement policy preferences that least distort competitive markets, including through non-technology specific incentives<br>• Clarifying Federal and State jurisdictions in the electricity sector |
| 6. | Adopt carbon tax or pricing scheme as an economically efficient way to recognize low-carbon resources |
| 7. | Redesign energy and ancillary service markets to:<br>• Remove restrictions that limit technology participation<br>• Better reward performance<br>• Incentivize needed capacity<br>• Support long-term capital investment<br>• Build balanced, forward-looking resource portfolios<br>• Ensure essential reliability services are included and valued appropriately<br>• Enforce against out-of-market measures<br>• Adjust markets to bring state policies into them |
| 8. | Redesign wholesale energy markets to reduce the impacts of potentially inefficient or preferential features:<br>• Negative pricing and production tax credits and market clearing price setting<br>• Price caps<br>• Scarcity mechanisms<br>• Role of storage and customer-side resources (efficiency, demand response, microgrids, solar photovoltaic, electric vehicles, combined heat and power)<br>• Ex-ante price readjustments<br>• Develop both comprehensive and user friendly analytic tools supporting energy market redesign and decision-making<br>• Address uplift |
| 9. | Incorporate additional zero or lower-emission power sources in portfolio standards. |
| 10. | Support utility, grid operator, and consumer efforts to enhance reliability and resiliency: |

| | |
|---|---|
| | • Improve analytical tools for system planning and portfolio analysis<br>• Strengthen capabilities for state and federal support for reliability and resiliency measures and activities<br>• Facilitate distributed and grid-edge technologies to support system stability, reliability, and resiliency |
| **11.** | Coordinate electricity and natural gas systems when dealing with capacity expansion, market rules and products, operational concerns, and regional needs. |
| **12.** | Develop mechanisms to compensate or require essential energy services (e.g., reliability, resilience, security) that are necessary to operate the grid and reflect product attributes desired by consumers (e.g., low-emissions, clean, flexible).<br>• Assess potentially under-recognized contributions from baseload plants<br>• Develop new methods (market mechanisms, interconnection requirements, contracts, technology) that enhance reliability and resilience<br>• Mitigate fuel availability concerns through a full suite of operational, contractual, and technology alternatives<br>• Expand the use of power purchase agreements as a way to stabilize markets and reliability mechanisms<br>• Ensure new bulk power and distributed resources have capability and incentive to provide essential energy and reliability services Enable utility participation in developing customer-side resources (efficiency, demand response, microgrids, solar photovoltaic, electric vehicles, combined heat and power) to enhance customer options and reduce integration challenges |
| **13.** | Expand use of innovative and flexible resources--such as energy storage, demand response, energy efficiency and fast ramping generation- to contribute to grid stability, resilience, and reliability within the bulk power and distribution systems.<br>• Remove market restrictions<br>• Redefine reliability products and compensation schemes<br>• Continue RD&D on storage and other technologies that contribute to improve flexibility and reliability<br>• Develop technologies to improve flexibility of existing thermal generators |
| **14.** | Expand regional market and operations boundaries to achieve more effective integration of reliability services and assets<br>• Market implications of regional integration<br>• Strengthen the connections within and between transmission systems<br>• Mitigate market and operational seams between organized and bilateral market regions. |
| **15.** | Build portfolios of diverse resources that balance and improve reliability, resilience, affordability while respecting state and societal preferences<br>• Continue RD&D on technologies and methods to meet broader societal and state preferences |
| **16.** | Eliminate all subsidies, incentives, payments, tax benefits to truly level the playing field for all energy sources |
| **17.** | Compensate demand-side resources to meet customer needs in ways that support the grid<br>• Update net metering policies to reflect total grid system costs and maturing nature of DER technologies.<br>• Manage DER (including curtailments) to support the broader stability, security, and reliability of the power grid. |

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| **18.** | Utilize existing federal authorities under the Federal Power Act (202c) to direct emergency out-of-market operations for baseload and other grid assets to ensure the reliability of the power system. |
| **19.** | Accelerate pace and final resolution of regulatory and policy agency decisions on infrastructure, markets, reliability and other policy issues |
| **20.** | Develop safeguards, training, and direct assistance to protect workers, jobs, and communities from the devastating impacts of energy market shifts. |
| **21.** | Expand electrification of multiple end-uses (vehicles, industrial processes, heating) to better match electric generation variability and needs and provide reliability services<br>• Fast-tracking electric vehicle charging station deployment at national highway rest stops<br>• Encouraging industrial process electrification<br>• Conducting early-stage R&D to increase industry options |
| **22.** | Encourage adoption of outcome-based regulations at the state and federal levels, wherever allowed by statute<br>• Reduce use of prescriptive regulations where markets can be enabled<br>• Avoid picking winners and losers<br>• Use market incentives and/or penalties for non-performance, not regulations<br>• Reserve use of prescriptive regulations for public safety and emergency conditions or where specific performance is required for reliability and equipment protection |

# 10 Recommendations

TBD

# Glossary of Key Terms and Concepts

*Affordability:*

*Ancillary services:*

*Balancing authority:* The responsible entity that integrated resource plans ahead of time, maintains load-interchange-generation balance within a balancing area, and supports interconnection frequency in real time. Currently 66 BAs manage the bulk power system in the lower 48 states.

*Base load or minimum load:* In a given geographic area, the minimum amount of electric power (MW) typically required by consumers over a given period at a constant rate.

*Baseload power plant:* Baseload generation has historically been power plants that run almost continuously to serve a base level of demand that is typically present on the system due to everyday needs. Most often, nuclear plants, large thermal units, or hydroelectric plants are considered base-load generation. This type of generation is usually large with respect to size and output, and operates within a steady range of production. Baseload units have low operating costs and have been operated to maximize the plant's mechanical and thermal efficiency and minimize system operating costs.

*Bilateral contract:* Bilateral transactions for electricity occur between two parties without going through an RTO's organized market. They can be arranged through a negotiated long-term contract or for a short-term exchange (hourly or monthly) through a voice broker or an electronic brokerage platform. Bilateral contract prices are often linked to the prices set in centrally organized markets.

*Bulk power system, or BPS:* Statutory definition from EPAct 2005, ''(1) The term 'bulk-power system' means— ''(A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and ''(B) electric energy from generation facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy." More broadly, the BPS is used to include utility-scale generation and storage as well as transmission and system control and communications facilities.

*Capacity:* A measurement of the maximum output that generating equipment can supply to a system load, commonly expressed in megawatts. Differs from the term "generation," which measures the actual electricity produced, allowing for equipment down time.

*Capacity factor*: The ratio of the electrical energy produced by a generating unit over a given period of time, relative to the electrical energy that could have been produced at continuous full power operation over the same time period. For example, a 10 MW generating unit running continuously would produce: 365 days x 24 hours x 10 MW = 87,600 megawatt-hours of electricity.

*Centrally organized markets*: Regional Transmission Operators and Independent System Operators manage centrally organized electricity markets serving two-thirds of the nation. All of these markets offer day-ahead markets, which schedule electricity production and consumption before the operating day, while the real-time (or balancing) market reconciles differences between the day-ahead market schedule and real-time load subject to factors such as reliability, asset outages and transmission limits. These energy markets match sellers' bids with buyers' offers to set market-clearing prices (also called Locational Marginal

Prices) that are paid to all sellers for all electricity consumed as often as every five minutes. Most RTOs and ISOs also run markets for ancillary services and some run capacity markets.

*Demand:* the rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time.

*Economic carrying capacity:* the idea that limits to renewable energy penetration are limited by economics rather than engineering, driven by factors that include transmission and the flexibility of the power grid to balance supply and demand. Economic carrying capacity is the point at which variable renewable energy is no longer economically competitive or desirable to the grid or society.

*Economic dispatch:* The practice by balancing authorities of operating their area's generation fleet and demand response resources so that the lowest-cost resources are used first, followed when needed by more expensive resources and bids. In practice, economic dispatch is modified to reflect system reliability requirements and transmission operating limits, so it becomes security-constrained economic dispatch.

*Essential reliability services (ERSs):* Services that must be available to grid operators when needed to enable the reliable transfer of electricity from generation sites to consumers. They include frequency response (including regulation, contingency reserve and load following), reactive power and voltage support, and ramping capability. ERSs were formerly known as "ancillary services," but have been renamed to more fully recognize their functional importance. Various ERSs may be provided by generation, storage and demand-side resources.

*Facility:* a set of electrical equipment that operates as a single element (e.g., a line, a generator, a shunt compensator, transformer, etc.)

*Flexibility:* The ability of a resource—whether it is a component or a collection of components of the power system—to respond to the scheduled or unscheduled changes of power system conditions at various operational timescales.

*Frequency response:* the ability of a system or elements of the system to react or respond to a change in system frequency. In North America, system frequency is maintained at or very close to 60 cycles per second.

*Fuel security:* In a given area, the extent to which, in a given area, the BPS depends on fuels or fuel sources that are readily accessible and sufficient to enable operation in the event of a fuel supply disruption

*Generation/fuel diversity:* The extent to which, in a given area, customer electricity is generated from diverse fuels and technologies. Generation diversity is enhanced by energy efficiency, which reduces customers' need for generation.

*Independent System Operator:*

*Interconnection*: a geographic area in which the operation of bulk power system components is synchronized such that the failure of one or more of such components may adversely affect the ability of the operators of other components within the system to maintain reliable operation of the facilities within their control.

*Load:* An end-use device or customer that receives power from the electric system. Collectively, load refers to all customers' electricity use, whether for energy (MWh) or capacity (MW).

*Peaking capacity:* Generation units that are normally used only during the hours of highest daily, weekly, or seasonal loads. These units are designed to be turned on or off at short notice as needed and typically have relatively low capital costs and high operating costs.

*Ramping:* the ability of a generator to increase or decrease real power (megawatts) in response to changes in system load, interchange schedules or generator output, in order to maintain grid reliability and compliance with applicable NERC standards

*Reactive Power:* the portion of electricity that establishes and sustains the electric and magnetic fields of alternating current equipment.

*Regional Transmission Operator (RTO):*

*Reliability Standard:* A requirement approved by FERC to provide for reliable operation of the bulk power system. The term includes requirements for operating existing bulk power system facilities and for planning or modifying facilities to assure the reliable operation of the bulk power system. Reliability standards include cyber-security and physical security requirements, but they not include any requirement to enlarge or build new transmission or generation capacity.

*Reliability:* The ability of the system to continue operation while some lines or generators are out of service. To be reliable, the BPS must satisfy two fundamental requirements simultaneously:

1) Adequacy – the system must have the physical capacity (i.e., generation, transmission, and related assets) to supply the aggregate electric power and energy requirements of electricity consumers at all times, taking into account scheduled and reasonably expected unscheduled outages of system components; and

2) Operations – the ability of the BPS to remain functional despite sudden disturbances to system stability or unanticipated loss of system components.

*Reliable operation*: operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements.

*Resilience:*

*Resource adequacy*: The ability to provide adequate supply during peak load and generation outage conditions, which includes both supply-side and demand-side resources as contributors to meeting aggregate electrical demand (including losses)[129] while accounting for "scheduled and reasonably expected unscheduled outages of system elements."[130]

*Security:*

*Sustainability:*

*Variable renewable energy (VRE):* Renewable energy generated from variable sources such as wind and solar (as distinct from renewable sources such as geothermal or biomass, which have relatively predictable availability). VRE, especially at relatively high penetrations in a grid, can pose several challenges to the grid, including variability, uncertainty, location-specificity, non-synchronous generation, and low capacity factors; most or all of these challenges can be mitigated.

*Voltage Control:*

# Appendix A: Memo from Secretary Perry

April 14, 2017

MEMORANDUM TO THE CHIEF OF STAFF

FROM: Rick Perry

SECRETARY OF ENERGY

SUBJECT: STUDY EXAMINING ELECTRICITY MARKETS AND RELIABILITY

At the most recent G7 Energy Ministerial, my colleagues discussed the need for an energy transition utilizing greater efficiency and fuel diversity. There was also notable concern about how certain policies are affecting, and potentially putting at risk, energy security and reliability. It impressed upon me that the United States should take heed of the policy choices our allies have made, and take stock of their consequences.

A reliable and resilient electric system is essential to protecting public health and fostering economic growth and job creation. The U.S. electric system is the most sophisticated and technologically advanced in the world. Consumers utilize heating, air conditioning, computers, and appliances with few disruptions. Nonetheless, there are significant changes occurring within the electric system that could profoundly affect the economy and even national security, and as such, these changes require further study and investigation.

Baseload power is necessary to a well-functioning electric grid. We are blessed as a nation to have an abundance of domestic energy resources, such as coal, natural gas, nuclear, and hydroelectric, all of which provide affordable base load power and contribute to a stable, reliable, and resilient grid. Over the last few years, however, grid experts have expressed concerns about the erosion of critical baseload resources.

Specifically, many have questioned the manner in which baseload power is dispatched and compensated. Still others have highlighted the diminishing diversity of our nation's electric generation mix, and what that could mean for baseload power and grid resilience. This has resulted in part from regulatory burdens introduced by previous administrations that were designed to decrease coal-fired power generation. Such policies have destroyed jobs and economic growth, and they threaten to undercut the performance of the grid well into the future. Finally, analysts have thoroughly documented the market-distorting effects of federal subsidies that boost one form of energy at the expense of others. Those subsidies create acute and chronic problems for maintaining adequate baseload generation and have impacted reliable generators of all types.

Each of these and other related issues must be rigorously studied and analyzed, and the Department of Energy is uniquely qualified for the task. The results of this analysis will help the federal government formulate sound policies to protect the nation's electric grid. In establishing these policies, the Trump Administration will be guided by the principles of reliability, resiliency, affordability, and fuel assurance-principles that underpin a thriving economy.

I am directing you today to initiate a study to explore critical issues central to protecting the long-term reliability of the electric grid, using the full resources and relationships available to the Department. By Wednesday, April 19, 2017, present to me an implementation plan to complete this study 60-days from that date, that will explore the following 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.

I have committed to the President that this report will not only analyze problems but also provide concrete policy recommendations and solutions. I also committed to the President that I will do everything within my legal authority to ensure that we provide American families and businesses an electric power system that is technologically advanced, resilient, reliable, and second to none.

**Table X. Key Laws Related to Electricity Generation**

| Name | Year Enacted | Major Provisions |
|---|---|---|
| **Federal Power Act** | 1920; amended 1935, 1978, 1980, 1986, 1992, 2005 | • Established the Federal Power Commission (now the Federal Energy Regulatory Commission) to regulate the interstate activities of the electric power and natural gas industries, and to coordinate national hydropower activities<br>• Amendments in 1935 expanded the Commission's jurisdiction to include all interstate electricity transmission and wholesale electricity sales |
| **Atomic Energy Act** | 1954 | • Established Federal regulatory authority over civilian uses of nuclear materials and facilities exercised through the Nuclear Regulatory Commission<br>• Delineated Federal/state jurisdiction for nuclear material and facilities: licensing of nuclear plant construction and operation as well as waste disposal are exclusively in the Federal domain. States retain oversight of generation planning by vertically integrated utilities (e.g., questions of whether or not to construct nuclear facilities in the first place). |
| **Price Anderson Act** | 1957 | • Facilitated the development of nuclear-powered generating capacity by establishing a program for covering claims of members of the public if a major accident occurred at a nuclear power plant and providing a ceiling on the total amount of liability for nuclear accidents. |
| **Clean Air Act Amendments** | 1970, 1977, and 1990 | • Authorized comprehensive Federal and state regulation of stationary pollution sources, including power plants[131]<br>• Created the National Ambient Air Quality Standards (NAAQS), State Implementation Plans (SIPs), New Source Performance Standards (NSPS, and National Emission Standards for Hazardous Air Pollutants (NESHAP).[132] [133]<br>• Requires states to decide what pollution reductions will be required from particular sources and to submit a State Implementation Plan.[134]<br>• The 1990 CAA Amendments direct the creation of an acid rain program (ARP)[135] and created new regulatory authorities, including an emissions cap-and-trade system to reduce air pollution.[136] The 1990 CAA Amendments also require EPA to regulate 189 specified hazardous air pollutants[137] and set up specific procedures to determine whether the air pollution regulations would apply to power plants that run on fossil fuels[138] |
| **National Environmental Policy Act** | 1970 | • Requires Federal agencies to review the environmental consequences of a proposed project before granting approval.t Agencies prepare statements on the environmental impact of a proposed project (Environmental Impact Statement or Environmental Assessment), considering the views of the public and of other Federal, state, and local agencies, and make the report publicly available.[139] |

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| Clean Water Act | 1972[ggg] | • Authorized regulation for pollutant discharge through the creation of the National Pollutant Discharge Elimination System (NPDES) program, which requires polluting sources to obtain a permit authorizing pollution up to a specified limit.<br>• Regulated pollutants include thermal pollution (heat), conventional pollutants (e.g., dissolved solids and bacteria), and toxic pollutants[140]<br>• Regulated wastewater discharges from the power sector include cooling water, wastewater from coal ash handling, wastewater from pollution control equipment, and other wastewater streams |
| Energy Policy and Conservation Act (EPCA) | 1975 | • Set test procedures, conservation targets (followed by standards if targets are not set) and appliance labeling requirements<br>• Authorized establishment of Strategic Petroleum Reserve |
| Resource Conservation and Recovery Act (RCRA) | 1976, amended 1984, 1986 | • Provides EPA with the authority to regulate hazardous waste,[141] including management of power sector waste, such as coal ash<br>• Directs the EPA to study promising techniques of energy recovery from solid waste and solid waste from mining[142] |
| National Energy Act | 1978 | • Passed in response to oil shortages in the 1970s and the increased reliance on imported oil, which was seen as a threat to national security[143]<br>• Legislation included five statutes:<br>1) Natural Gas Policy Act of 1978—granted FERC authority over intrastate and interstate natural gas production; set rules for natural gas price ceilings, how to allocate costs, and emergency supply authority.<br>2) Public Utility Regulatory Policies Act (PURPA)—left to states to implement; promoted renewable energy, encouraged energy conservation, ended practice of customers paying less for electricity with increasing usage, allowed some deregulation<br>3) Energy Tax Act—enacted tax credit for some distributed renewable generation<br>4) Powerplant and Industrial Fuel Use Act—restricted use of oil and natural gas for power generation, promoted coal, nuclear, and other alternative fuels; repealed in 1987<br>5) National Energy Conservation Policy Act—made energy efficiency targets into mandatory standards and extended or enacted additional energy conservation measures |
| National Appliance Energy Conservation Act (NAECA) | 1987, amended in 1988 | • Set standards and schedule for DOE to conduct rulemakings<br>• Amended in 1988 to add fluorescent ballasts |
| Energy Policy Act | 1992 | • Provided FERC greater authority to provide transmission access for wholesale buyers in procuring wholesale electricity<br>• Included a wide variety of energy efficiency measures, including building energy efficiency standards, equipment energy efficiency standards (including motor standards), measures that encourage and support industrial energy efficiency improvements, and mandates and funding for Federal agencies to improve their energy efficiency<br>• Included the first renewable electricity production tax credit for wind, biomass, landfill gas, and other renewable sources. |

[ggg] The Clean Water Act was significantly amended in 1972. Parts of the legislation have been changed many times since. https://www.epa.gov/laws-regulations/history-clean-water-act

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| | | • Amended EPCA to expand coverage to certain commercial and industrial equipment<br>• Amended the Federal Power Act to expand FERC's jurisdiction to include electricity system reliability and certain power plant sales<br>• Directed DOE to conduct a five-year program on technologies to increase the recoverability of domestic oil resources through R&D on oil shale extraction and conversion, and expansion of the recoverable natural gas resource base<br>• Directed EPA to promulgate public health and safety standards governing releases from radioactive materials in the Yucca Mountain repository, and directed DOE to developed a five-year civilian nuclear program, and to conduct a five-year technical and financial assistance program to encourage the development and submission for certification of advanced light water reactor designs |
| **Energy Policy Act** | 2005 | • Gave FERC responsibility for mandatory reliability standards and allowed the agency to certify an electric reliability organization to develop and enforce those standards. FERC then designated the North American electric Reliability Corporation (NERC) as the designated electric reliability organization.<br>• Established an investment tax credit for solar energy and advanced coal electricity generating systems, a production tax credit for hydropower and advanced nuclear power systems, and energy efficiency tax credits<br>• Removed regulations on natural gas produced by hydraulic fracturing under the Safe Drinking Water Act<br>• Set standards and schedule for DOE to conduct appliance standard rulemakings<br>• Amended PURPA to require electric utilities to make net metering and smart metering available upon consumer request, and to terminate mandatory purchase and sale requirements pertaining to cogeneration and small power production utilities<br>• Modified federal leasing and royalty rules to facilitate and encourage the development of coal deposits on federal lands<br>• Provided incentives for the natural gas industry, such as reduced royalty rates for select natural gas producers, accelerated depreciation for natural gas distribution and gathering lines, and preferential tax treatment for natural gas production |
| **Energy Independence and Security Act (EISA)** | 2007 | • Set appliance, lighting, and industrial electric motor efficiency standards, and added stand-by power and 6-year-look back provision<br>• Added Section 1705 to the loan guarantee program, allowing subsidized loans to commercial facilities<br>• Called for coordination to develop a framework for smart grid interoperability standards<br>• Increased funding for the R&D and large-scale demonstration projects of carbon capture and storage systems |
| **American Recovery and Reinvestment Act (ARRA)** | 2009 | • Provided $31 billion in funding for DOE's energy efficiency, renewable energy, fossil energy, and electricity delivery and energy reliability program offices, as well as Title XVII loan guarantees for innovative clean energy technologies; investments in energy infrastructure, including transmission and smart grid technologies; and other major investments in energy administered by DOE.[144]<br>• Established a temporary program for the rapid deployment of renewable energy and electric power transmission projects. |
| **American Energy** | 2012 | • Added appliance standards coverage for other types of motors and 6-year look-back for certain products[145] |

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| **Manufacturing and Technical Corrections Act (AEMTCA)** | | |

**Table Y. Key Regulations and Orders[hhh] Related to Electricity Generation**

| | | | | Key Provisions Related t Electricity Generation |
|---|---|---|---|---|
| **Name** | **Year Finalized[iii]** | **Year (s) Implemented** | **Authorizing Statute[jjj]** | **Major Provisions** |
| **National Ambient Air Quality Standards (NAAQS)** | First NAAQS set in 1971<br><br>Most recent revisions in<br>2010 ($SO_2$ & $NO_2$),<br>2013 (PM), and 2015 (ozone) | Attainment schedule depends on severity of non-attainment<br><br>Attainment of 2015 ozone NAAQS by 2020-2037 | Clean Air Act (1970) | • Established primary and secondary NAAQS[kkk] f six common "criteria" air pollutants. Power plar are sources of four of these pollutants: sulfur dioxide ($SO_2$), nitrogen dioxide ($NO_2$), particula matter (PM), and ozone ($O_3$).<br>• Clean Air Act (CAA) directs EPA to review the NAAQS every 5 years.<br>• NAAQS first established in 1971.[146] [147] $SO_2$ NAAQS were revised in 1996 and 2010;[148] [149] N NAAQS were revised in 1985, 1996, and 2010;[151] [152] $O_3$ NAAQS were revised in 1979, 1997, 2008, and 2015; PM NAAQS were revised in 1 1997, 2006, and 2013. |
| **Steam Electric Effluent Limitations Guidelines (ELG)[153]** | 1974, updates in 1977, 1978, 1980, 1982, 2015 | 2015 limits are 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.<br>• 2015 update sets first federal limits on levels of toxic metals that can be discharged |
| **New Source Performance Standards for Coal-Fired Power Plants** | 1979 | 1979 | Clean Air Act (1977) | • EPA rule governing sulfur dioxide emissions fr coal power plants[154]<br>• Effectively required flue gas desulfurization on new coal plants. |

[hhh] Research and development tax incentives are not included

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

[jjj] For Regulations Only

[kkk] Primary standards are set at levels "requisite to protect the public health." Secondary standards provide public welfare protection, including protection against decreased visibility and damage to animals, crops, vegetation, and buildings. The secondary standard carries no deadline for attainment and has never been the subject of penalties or sanctions for areas that failed to meet it. For this reason, only primary standards are included in this table.

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| **FERC Order 636 – Restructuring of Pipeline Services**[155] | 1992 | 1992 | | • Required pipeline companies to provide open-access transportation services that are equal in quality whether the gas is purchased directly fro the pipeline company or elsewhere<br>• Included provisions designed to increase access increase the quality of transportation services an provisions to promote competition among gas suppliers |
| **Acid Rain Program** | 1993 | Phase 1 Implementation: 1995-2000<br>Phase 2 Implementation:<br>2000-2010 | Clean Air Act (1990) | • Created the world's first large-scale emission ca and-trade system to reduce air pollution. Effectively superseded by Cross-State Air Pollution Rule<br>• Established a tightening annual $SO_2$ emissions c for power plants fired by coal, oil and gas.<br>• Applies individual NOx emission rates on certai coal-fired boilers. |
| **FERC Order 888**[156]- Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities | 1996 | 1996 | | • Mandates non-discriminatory open access electricity transmission grid.<br>• Allows utilities that own transmission servic to recoup costs<br>• Allowed Independent System Operators tc form and facilitated economic dispatch of electricity across a larger geographic area |
| **NOx Budget Trading Program** | 1998 | 2003; Program ended: 2008 | Clean Air Act | • Established a market-based cap and trade program to reduce NOx emissions from pc plants and other sources to help states me the 1997 ozone NAAQS.<br>• Trading program applied to 20 states plus Washington, D.C. |
| **Regional Haze Rule** | 1999 | 2001-2018[157] | Clean Air Act | • Requires States to develop long-term strategies including enforceable measure improve visibility in 156 national parks an wilderness areas.<br>• Aims at returning visibility to natural cond within 60 years. |
| **Cooling Water Intake Rule**[158] | 2001 (phase 1), 2003 (revised phase 1) 2014 (phase II) | Phase I: 2001, revision began 2003 | Clean Water Act | • Promulgated under 316(b) of the Clean V Act. New sources regulated under Phase existing sources regulated under Phase I<br>• Promulgated to reduce mortality to fish a other aquatic organisms. |
| **Clean Air Interstate Rule (CAIR)** | 2007 | $NO_x$ program began in 2009 and SOx program | Clean Air Act | • Required 27 eastern states + Washingtc to limit power sector emissions of nitroge oxides and sulfur dioxide to address reg |

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| | | in 2010. Rule superseded in 2014. | | transport that contributes to the formation o fine particulate matter and ozone.<br>• The NOx program replaced the NOx Budge Trading Program, and the SO2 program wa designed to continue reductions below the ARP permanent cap. Both programs used a cap-and-trade systems.<br>• Ended January 1, 2015. |
| **Cross-State Air Pollution Rule (CSAPR) and CSAPR Update** | 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 redı power plant emissions of $SO_2$ and NOx that contribute to ozone emissions and fine parti pollution in other states.[159]<br>• Aligns compliance with the July 2018 attainment date for the 2008 ozone NAAQS Moderate area attainment date. |
| **FERC Order 1000[160] - Transmission Planning and Cost Allocation** | 2011 | 2011 | | • Requires regional and interregional transmission planning; mandates that the planning process consider transmission nee driven by public policy requirements<br>• Requires regional and interregional cost allocation methods that satisfy six allocatior principles<br>• Eliminates the Federal right of first refusal ir FERC jurisdictional tariffs and agreements.[1] |
| **Mercury and Air Toxics Standards[162]** | 2012 | 2015-2016 | Clean Air Act (1990) | • Establishes emissions limits for mercury, arsenic, acid gases, and other toxic pollutar from coal- and oil-fired power plants.[163]<br>• Utilities had until April 2015 to comply with t standards—through the deployment of wide available and economically feasible technologies, practices, and strategies—wit many plants receiving a one-year extension |
| **Coal Combustion Residuals (CCR) Rule[lll]** | 2015 | Not yet implemented | Resource Conservation and Recovery Act (1976) | • Addresses groundwater contamination risks fror CCR (i.e., "coal ash") disposal in unlined landfi and surface impoundments.<br>• Establishes national standards for new and exist CCR landfills and new and existing CCR surfac impoundments. |
| **Carbon Pollution Standards and Clean Power Plan[164]** | 2015 | Under review | Clean Air Act | • Carbon Pollution Standards established carbon dioxide emission standards for new fossil fuel-fired generators under Clean Air / section 111(b).<br>• The Clean Power Plan, promulgated under section 111(d) of the CAA, establishes |

[lll] 80 FR 21302

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| | | | | greenhouse gas emissions standards for existing power plants. |
| **FERC Order[mmm] No. 825 Settlement Intervals and Shortage Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators** | 2016 | 2016 | | • Established settlement interval and shortag pricing requirements.<br>• Makes final reforms in these two areas proposed in a September 2015 Notice of Proposed Rulemaking.<br>• FERC stated that "[t]hese requirements will help ensure that rates for energy and operating reserves are just and reasonable and will align prices with resource dispatch instructions and operating needs, provide appropriate incentives for resource performance and maintain reliability."[165] |
| **FERC Order No. 827 Reactive Power Requirements for Non-Synchronous Generation** | 2016 | 2016 | | • All newly interconnecting non-synchronous generators will be required to provide react power at the high-side of the generator substation as a condition of interconnectioi set forth in their Large Generator Interconnection Agreement (LGIA) or Sma Generator Interconnection Agreement (SG as of the effective date of the Final Rule. |
| **FERC Order No. 828 Requirements for Frequency and Voltage Ride Through Capability of Small Generating Facilities** | 2016 | 2016 | | • Requirements for Frequency and Voltage Through Capability of Small Generating Facilities, issued July 21, 2016. The Commission revised the SGIA to require generators no larger than 20 MW to have voltage and frequency ride through capabilities. |
| **FERC Order No. 831 Offer Caps in Markets Operated by Regional Transmission Organizations and Independent System Operators** | 2016 | 2016 | | • Retained an existing $1,000/MWh price c energy offered in day-ahead and real-tim markets.<br>• Also allows prices, for the purpose of calculating locational marginal prices, to r $2,000/MWh, provided offers are based c verified costs.<br>• FERC stated that it found that "during the 2013-14 "Polar Vortex" led to a significar in the price of natural gas that may have caused some resources with must-run requirements to operate at a loss becaus their short-run marginal costs exceeded $1,000/MWh offer cap in place at the tir |

* National Ambient Air Quality Standards do not directly impact power plants or impose any compliance costs on power plants. Instead, NAAQS establish national air quality standards, and states are responsible for developing State Implementation Plans (SIPs) for meeting air quality standards. NAAQS for $NO_2$, $SO_2$, and $O_3$ are included here because power plants are major sources of $NO_2$ and $SO_2$

[mmm] There are many more FERC dockets related to this study for specific companies or regional operators. The broader non-entity specific orders relevant to this study are listed above.

emissions, and because $NO_2$ reacts in the atmosphere to form $O_3$. The installation of pollution control systems on power plants is one possible compliance tool that states may choose to achieve the NAAQS.

# Appendix C. Key Environmental Regulations and Statutes[nnn]

| Key Provisions Related to Electricity Generation | | | | |
|---|---|---|---|---|
| **Name** | **Year Enacted** | **Date of Expiration if Exists** | **Initial Authorizing Statute** | **Major Provisions** |
| **Intangible Drilling Expenses** | 1916, amended 1954 | | Internal Revenue Code of 1954 | • Taxpayers may elect to currently deduct intangible drilling costs (IDCs) paid or incurred with respect to the development of an oil or gas property located in the United States. IDCs include wages, machinery used for grading and drilling, and unsalvageable materials used in developing wells. |
| **Depletion Allowance** | 1926, amended 1932, 1954, 1969, 1975, 1978 & 2005 | | Energy Tax of 1978 | • Currently, percentage depletion is allowed for independent producers at a rate of 15% for oil and gas and 10% for coal. Percentage depletion is allowed on production up to 1,000 barrels of average daily production of oil (or its equivalent for natural gas). The depletion allowance cannot exceed 100% of taxable income from the property (50% for coal) or 65% of the producers taxable income from all sources. Percentage Depletion for Geothermal was authorized in 1978.[167] |
| **Characterizing Royalty Payments as Capital Gains** | 1954, amended 1986 | | Internal Revenue Code 1954 | • Income from the sale of coal under a royalty contract may be treated as a capital gain rather than ordinary income. |
| **Oil & Gas: Royalty Relief** | 1978, amended 1995, 2005 | | Outer Continental Shelf Lands Act 1978 | • Relief from oil and gas royalty obligations may be granted to increase production or to encourage development on certain producing or non-producing leases. |
| **Tax-Exempt Interest on Industrial Development Bonds** | 1980 | | Windfall Profit Tax Act of 1980 | • State and local electric utilities can issue tax-exempt bonds for the development of facilities producing fuel from solid waste.[168] |
| **Section 29 Tax Credits for Production from Unconventional Fuels** | 1980 | 2002 | Windfall Profit Tax Act of 1980 | • Provided tax credit for production of nonconventional fuels including, coal seams, coal-based synthetic fuels nonconventional gas and gas from biomass.[169] [170] |

nnn Research and development tax incentives are not included

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| **Certain publicly traded partnerships treated as corporations for tax purposes (Secs. 7704 & 851)** | 1987 | | **Omnibus Budget Reconciliation Act of 1987** | • General rule that a publicly traded partnership is taxed as a corporation is not applicable if 90% of gross income is interest, dividends, real property rents, or certain other types of qualifying income; Other types of qualifying income includes income and gains from certain activities with respect to natural resources. |
| Renewable Electricity **Production Tax Credit (PTC)** | 1992, amended 2005, 2009, and 2016 | Varies by technology | EPAct 1992, | • The PTC is a per kilowatt-hour tax credit for electricity generated by qualified energy resources, lasting for 10 years from the date the facility is placed in service.<br>• 2.3¢/kWh for electricity generated from wind, geothermal, closed-loop biomass, and solar facilities (not claiming the ITC) that commenced construction prior to 2017.<br>• 1.2¢/kWh for open-loop biomass, landfill gas, municipal solid waste, qualified hydroelectric, and marine and hydrokinetic energy resources that commenced construction prior to 2017.<br>• The PTC is currently only available to new wind facilities, and the value of the credit will step down annually before being phased out completely n 2020 (i.e. new facilities will still receive 10 years of tax credit if placed in service before 2020). |
| **Accelerated Depreciation for Pollution Control Equipment** | 2005 | | EPAct 2005 | • Provides amortization allowance for certain certified air pollution control facilities used in connection with an electric generation plant that is primarily coal fired and that was placed in service after 1975. |
| **Investment Tax Credit (ITC)** | 2005, amended in 2008, 2009, and 2015 | Varies by technolog y | EPAct 2005 | • A tax credit that reduces the initial investment for select systems that generate electricity at a residence, commercial building, or utility scale. The expiration date and value of the ITC varies by technology.<br>• A 30% tax credit is currently available for residential solar electric and heating installations, with the value of the credit stepping down annually before expiring in 2022. The credit was previously available for residential fuel cells, geothermal heat pumps, and small wind-energy systems prior to 2017.<br>• For commercial installations, a 10% tax credit is available for geothermal electric systems, with no stated expiration date; a 24% credit is currently available for large wind systems, with the value of the credit stepping down annually before expiring |

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| | | | | in 2020; and a 30% credit is currently available for a variety of solar electric and heating technologies, with the value of the credit stepping down annually to 10% in 2022 and thereafter.<br>• A 20% tax credit is available for power generation projects that use integrated gasification combined cycle (IGCC) or certain other advanced coal-based electricity generation technologies |
| **Advanced Nuclear Production Tax Credit** | 2005 | 2020 | EPAct 2005 | • Production tax credit of 1.8 cents per kilowatt-hour of electricity produced by new nuclear power plants. Limited to 6,000MW and the first 8 years the plant is in service. Plants must be in service before 12/31/2000. |
| **Residential and Commercial Energy Efficiency Tax Credits** | 2005, amended 2008 (for residential only) | 2016 | EPAct 2005 | • A residential tax credit is available for energy improvements to existing homes.<br>• A tax deduction is available for certain qualifying systems and energy-efficient commercial buildings |
| **Amortization of geological and geophysical expenditures** | 2005 | | EPAct 2005 | • Oil and gas companies can amortize expenses related to geological and geophysical surveys over two years (independent producers) or seven years (large integrated producers (rather than over the lifetime of the project). |
| **Carbon Dioxide Sequestration Credit 45Q** | 2008 | After 75,000,000 metric tons of qualified carbon dioxide have captured in accordance with the statute. | Improvement and Extension Act of 2008 | • Credit for the sequestration of industrial source carbon dioxide produced at qualified U.S. facilities which may include coal and gas plants. Captured carbon dioxide can be re-injected as part of enhanced oil and natural gas recovery process. |

# Appendix F: External Technical References

(Draft as of June 26, 2017)

Reliability and Essential Reliability Services


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