
Advancing Past “Baseload” to a Flexible Grid

How Grid Planners and Power Markets Are Better Defining System Needs to Achieve a Cost-Effective and Reliable Supply Mix

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Executive Summary

In today's electricity system with low natural gas prices, negligible demand growth, and the proliferation of efficient natural gas-fired generation and renewable generation, "baseload" power plants like coal and nuclear are earning less market revenue than before. This report sheds light on why coal and nuclear plants have become less economical, why their ability to produce power continuously throughout most of the year is less essential in today's supply mix, and why operational flexibility is an increasingly important ingredient for a cost-effective supply of electricity. Overall, this report explains that the use of the term "baseload" generation is no longer helpful for purposes of planning and operating today's electricity system.

The term "baseload" generation is used with several different meanings. It historically functioned as shorthand for a category of resources that provided electricity production at relatively low operating costs. The output of "baseload" supply was thus used to meet the minimum of daily electricity demand levels. The term is reminiscent of a time when the resources it referred to, primarily coal and nuclear plants, were thought of as essential staples of bulk power supply. Due to the historical use of the term, "baseload" generation is often perceived to be connected with the concepts of system need and system reliability. For instance, use of the term can sometimes imply that coal and nuclear power plants play the same role in achieving the optimal supply mix today as they did before. However, this is not the case; the cost advantages once enjoyed by coal and nuclear plants have declined. The use of the term "baseload generation" may even distract regulators', planners', and markets administrators' attention from meeting emerging system and public policy needs in the most cost-effective manner.

The economics of traditional coal-fired and nuclear plants have been growing less favorable, particularly over the past several years, due largely to changing market fundamentals. These trends are strong and persistent. Natural gas prices have reached and are expected to remain near historical lows, reducing the previously favorable economics of coal-fired and nuclear power plants, and thereby leading to the displacement of coal generation as the most cost-effective source of bulk electricity production in many regions. The combination of low natural gas prices, low electricity demand growth driven by many economic factors, increased levels of energy efficiency and conservation, and rapid growth in renewable resources have substantially reduced the marginal costs and wholesale prices of electricity throughout the country. While these low prices benefit customers, they challenge the economic viability of some coal and nuclear generating plants, particularly the older, less efficient ones and those that would need significant capital expenditures to continue operating while meeting environmental or public safety requirements. Thus, decreasing wholesale power prices has been a major financial driver in the early (and previously unanticipated) retirement of some coal and nuclear facilities.

As some of the coal and nuclear plants face retirement decisions, focusing on their status as "baseload" generation is not a useful perspective for ensuring the cost-effective and reliable supply of electricity. Instead, system planners, market administrators such as regional

transmission organization, and other system operators should focus on a framework that: (a) effectively and efficiently defines and measures system needs and (b) develops planning tools, scheduling processes, and market mechanisms to elicit and compensate broad range of resources that have become available to meet those needs. Fortunately, planners and operators have been hard at work at such innovations and have moved past the concept of “baseload” to focus on the attributes of resources and the services they provide to the system that help the modernized electricity system operate more reliably, efficiently, and nimbly. While coal and nuclear power plants—as well as a broad range of other resource types—are recognized for providing a wide range of reliability services to the grid, the traditional definition of power supply resource adequacy is being revisited by some system operators and planners. Still, additional work is needed in planning and markets to better recognize and compensate resources for the value they provide to the system, and to incorporate the environmental impacts of electricity generation, including resources’ ability to reduce the system’s greenhouse gas emissions, consistent with public policy goals.

Coal and nuclear plants do not provide unique operational services that are specifically identified by or correlated with the term “baseload” generation. The term does not reflect the broader range of services that various resources can provide. As system planning and electricity market design are modernized, it is becoming increasingly clear that the services and attributes most under-recognized by today’s markets are greenhouse gas emissions in some jurisdictions and operational flexibility. A resource is considered flexible when it can react to operational signals to ramp its power generation up and down to help meet the needs of the system over multiple hours and minute-to-minute. Flexible resources can cost-effectively assist with meeting changing system loads and integrating the variable output of renewable resources. These flexibility needs are rapidly expanding as a result of numerous industry trends: (a) recognition by policymakers that renewable energy resources are needed to meet long-term emissions reductions goals; (b) customers’ increasing desire to voluntarily procure renewable energy or generate electricity on-site; and (c) substantial technological improvements that have driven down the cost of renewable resources to the point where, even before accounting for tax incentives, they are the lowest-cost option for new generating plants in some regions of the country.

Recognizing these trends, many studies examining system planning and electricity market design have demonstrated the increasing importance and value of flexible resources to meet the systems’ operational needs. Much of the renewable integration efforts to date are stimulating innovations that bring additional system benefits. For example, these efforts set the stage for integrating and expanding emerging new storage technologies to a more cost-effective scale, facilitating electrification of transportation and buildings, and bringing a fleet of highly flexible demand-side resources to participate in the wholesale market.

Efficient supply planning and operations require that a broad range of resources be considered and evaluated based on the services they provide, their attributes, and their joint ability to meet well-specified system and public policy needs. Historically, when energy market conditions were more stable, power plant scale economies were more significant, and there were fewer

technology choices available, many of the needed services and attributes were bundled and categorized as “baseload” and “peaking” plants. But now, given the current trends of market fundamentals, public policy goals, and customer preferences, labeling any resources as “baseload” and compensating them on that basis alone does not help improve our electricity system’s reliability, efficiency, or effectiveness. System planners and operators have been and are continuing to improve mechanisms for mobilizing and compensating the flexibility services that are needed to maintain a cost-effective and reliable electricity system. Doing so rewards both existing and new generating resources for the flexibility they can provide to support the system while encouraging additional operational improvements from all types of power plants, including solar and wind for which new technologies are enabling increased operational flexibility as well. More work is needed to expand the efforts in utilizing the most important operational characteristics of all resources to maintain reliable power supply, and to ensure that policies and electricity market design features can work together to attract and retain resources that meet system needs cost-effectively.

I. Introduction

The term “baseload” generation is an artifact of resource planning and operations over the last few decades, when most of our existing coal-fired and nuclear generating stations were developed. During most of that period, coal and nuclear plants offered significantly lower fuel costs than other technologies, which meant they operated around the clock to meet electricity customers’ “baseload” needs. When it came to constructing these plants, bigger was better because planners recognized the economies of scale associated with building large central-station power plants along with the transmission systems to transport that power to customers. Over time, the term “baseload” generation came to define this group of large power plants that were designed to operate at full capacity whenever possible, to capture the economies of scale inherent in their low variable cost. The next sections further explain the term “baseload” and provide context for why it became widely used in utility planning and the operations of the electricity grid.

A. THE TRADITIONAL APPROACH TO PLANNING A POWER SYSTEM

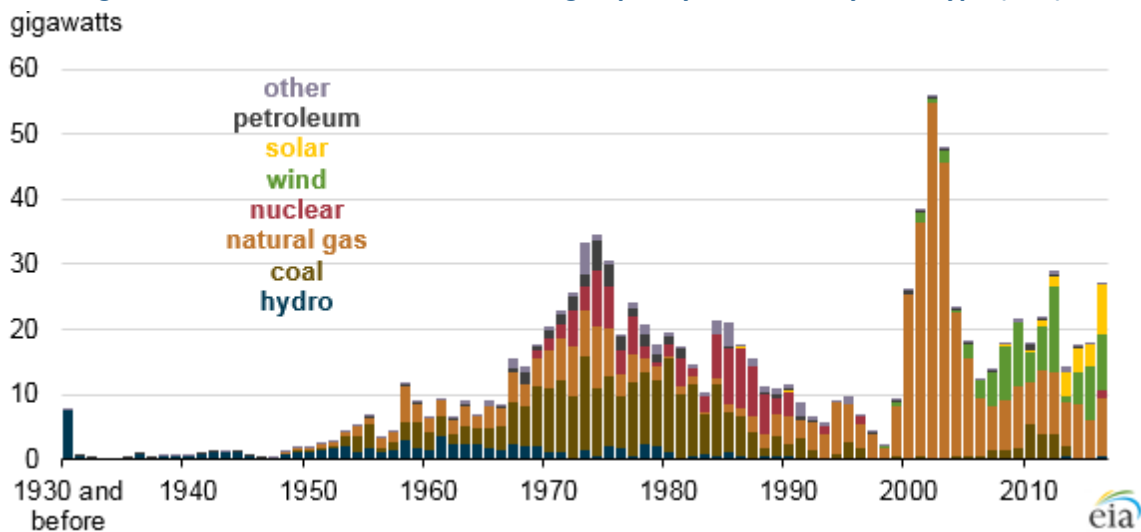
Traditionally, utilities built power plants and transmission and distribution systems to be able to generate power in bulk and to transmit that power to customers located in the utilities’ franchised service territories. In the 1970s and 1980s, large central-station coal and nuclear plants offered bulk power at relatively low variable costs to meet most or all of the minimum level of electricity consumed throughout the year. By sizing them to supply this baseload need of customers, the plants could operate around the clock, which was necessary to spread their high investment costs over the maximum amount of the electricity they could produce. By operating in this manner they could also avoid costly start-up and shutdown periods. Their low operating costs (*i.e.*, fuel costs and other variable costs) made such baseload operations cost-effective. Their relatively low operating costs made them a popular resource for utility planners to satisfy a large share of electricity needs, although in retrospect they often had capital costs well beyond what was expected. Integration of such large baseload plants into the electricity system typically required significant system upgrades, including investments in hydroelectric storage facilities, investments in large transmission infrastructure to spread generation over a larger region, and “contingency” management processes to avoid blackouts when one or more of these large power plants experienced unexpected outages.

The basic premise of the traditional utility planning processes developed over the last few decades remains unchanged today: utility planners start with the basic goal to provide reliable generation sources to deliver electricity in a cost-effective manner over time. They first perform an analysis of customer demand and electricity usage patterns, both historically and projected into the future. This includes a load forecast and a reliability assessment to determine the quantity of supply needed to be able to meet both peak demand as well as the electricity consumed throughout the year. In evaluating various options for developing the resources necessary to meet load, planners consider uncertainties, such as fuel cost uncertainties or load

uncertainties due to macroeconomic factors and weather. Utility planners also consider other market and regulatory uncertainties and risks that can affect the economics of various technologies. While the fundamental resource planning architecture has not changed in some parts of the country where generation investments continue to be the responsibilities of vertically-integrated utilities, in other parts of the country, the generation investment decisions are being made by private investors who must predict future market conditions and forecast future revenues. For example, in de-regulated states that operate within regional transmission organizations (RTOs) or independent system operators' (ISOs) footprints, the generation investment decisions are left to private investors, known as independent power producers (IPPs), who compete in the marketplace. In these areas, the grid operator sets market rules such that IPP investments will support a reliable system.

The results produced by the traditional planning architecture are dependent on the specific economic, technological, and environmental policy circumstances of the time and place. In particular, the generation resource mix identified to most cost-effectively meet defined system needs will vary significantly depending on technology costs, technology characteristics, and the availability and cost of fuels. Before 2008, the fuel cost of coal-fired generation was consistently below that of natural gas. Nuclear power, which has a relatively low fuel cost compared to many fossil-fired plants, went through a wave of popularity and was once (and inaccurately) promoted as the generation source of the future that would be “too cheap to meter.”¹ In the 1970s and 1980s, utilities developed many of these coal and nuclear resources, as shown in Figure 1.

Figure 1: 1930–2016 Annual Generating Capacity Additions by Fuel Type (GW)



Source: U.S. Energy Information Administration, *U.S. electric generating capacity increase in 2016 was largest net change since 2011*, February 27, 2017, available at <https://www.eia.gov/todayinenergy/detail.php?id=30112>.

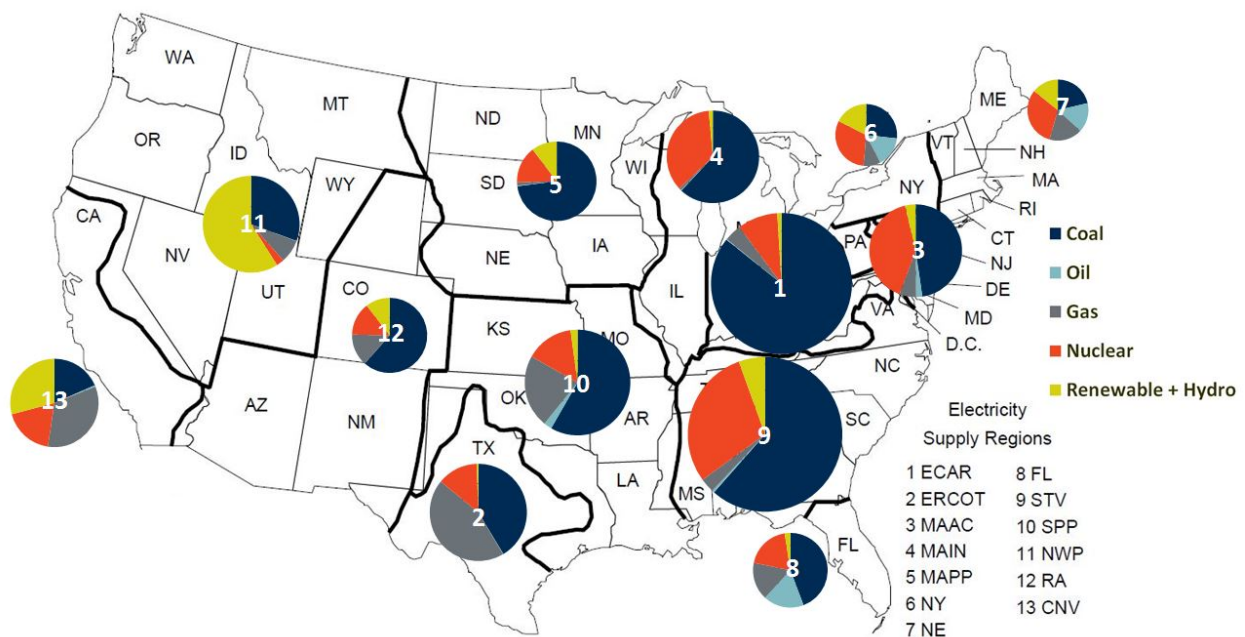
¹ For discussion of this phrase see, Wellock, Thomes, “‘Too Cheap to Meter’: A History of the Phrase,” U.S. Nuclear Regulatory Commission, June 3, 2016, available at <https://public-blog.nrc-gateway.gov/2016/06/03/too-cheap-to-meter-a-history-of-the-phrase/>

At the time when many fossil resources were developed, environmental and public health protections were less stringent or nonexistent. Thus, there was no internalization of the greenhouse gas (GHG) emissions, nor was the cost of GHG and other emissions “internalized” or incorporated in the price of wholesale electricity markets. Thus, the variable cost of using coal to produce electricity was limited to the commodity cost of the coal itself, plus the other relatively small variable costs of operating a coal-fired power plant. As a result, coal generation was viewed as a technology that could provide large quantities of electricity at very low variable costs, but there were some tradeoffs.

In the last two decades, policy makers have increasingly recognized the environmental and public health consequences of unchecked emissions, placing more stringent limits on emissions of particulates, sulfur dioxide, oxides of nitrogen, and heavy metals. In cases where emissions trading has been used to implement emissions reductions, some or all of the cost of such emissions from coal plants has been incorporated into markets. In more recent years, GHG emissions have been partially internalized through cap-and-trade mechanisms and through the clean-energy policies of some U.S. states. As also shown in Figure 1, this change in regulations and state policies has contributed to the development of new wind and solar resources, which has accelerated significantly since 2005 (as shown in the figure, a large share of new development between 2005 and 2015 was wind and solar).

In the year 2000, the majority of electricity produced in the U.S. came from coal and nuclear plants, as shown in Figure 2. The economics of power supply and the resulting generation mix varied by region, but most parts of the U.S. relied on coal and nuclear power to supply 50–90% of the electricity needs.

Figure 2: Share of Total Generation (MWh) in the Year 2000, by Region and Fuel Type

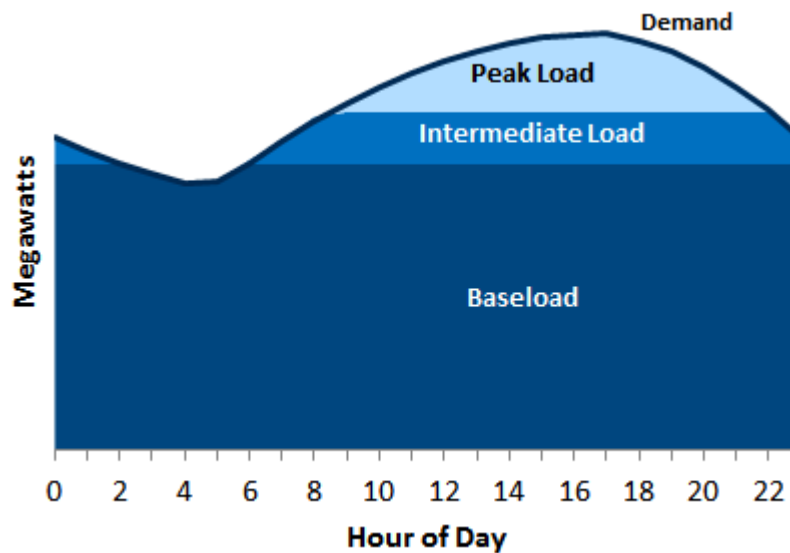


Source: Brattle analysis of data provided by: U.S. Energy Information Administration, *Annual Energy Outlook 2000*, Supplemental tables, <https://www.eia.gov/outlooks/aeo/archive.cfm>. Last accessed June 2017.

A. CLARIFYING THE CONCEPT OF “BASELOAD” GENERATION

Under the traditional resource planning paradigm, the optimal supply mix for reliable electricity was thought of as a “stack” of three types of generation: baseload, intermediate, and peaking generation. Figure 3 below illustrates this concept of dividing electricity demand and supply into these categories.

Figure 3: Conceptual Electricity Demand and Supply Mix in Traditional Planning



Source: The Brattle Group.

Because “baseload” power plants are large and generate electricity around the clock when available, some have suggested that these resources provide more “reliability” or a unique type of reliability in the wholesale power system compared to resources. In reality, however, system reliability is achieved by a mix of resources, not by any single unit. There is no special need for continuous power supply to come from a single unit (when available and not on outage) rather than a mix of resources. Today, it has become imperative for planners and grid operators to disentangle the traditional focus on baseload power from evolving system needs to cost-effectively and reliably operate the modern power grid. To do so, it is important to better understand what “baseload” generation is and what specific services it provides to customers.²

The term “baseload” generation can have slightly different meanings to different participants in the power industry, and “baseload” is not a well-defined term. It does not describe a technical capability. Yet it is often confused with operational services of power supply resources,

² In this report we stress the importance of identifying valuable resource services and attributes. Services and attributes refer to specific operational abilities. Examples of services and attributes include: ability to be available during constrained system hours, ability to ramp generation up or down at certain speeds, and ability to produce electricity without emissions.

primarily associated with coal and nuclear plants. It appears that the qualities that are sometimes associated with the concept of baseload resources include:

- Low-cost generation;
- The ability to provide available capacity during system peaks, system outages, or emergencies;
- Maintain fuel diversity.

What is Baseload?

“Baseload” generation is a long-standing shorthand term for a category of resources, including coal and nuclear plants that historically have provided relatively low-cost electricity production to meet around-the-clock electricity loads. Traditional baseload resources do not uniquely provide a special service or attribute that is not already being valued or considered in today’s markets and planning.

While some of the qualities listed above may be desirable from an economic or policy perspective, *they are not uniquely linked to the need or use of coal or nuclear generation.* Instead, the actual characteristics of a “baseload” plant or “baseload” demand are explained below:

Minimum Demand. “Baseload” can refer to the minimum level of customer demand, as shown above in Figure 3, over some contiguous period of time, such as a week, a month, a season, or a year. Bilateral power trading in peak and off-peak strips, for example, reflects this traditional approach to slicing load into horizontal strips that reflect either a minimum or an intermediate level of demand.

Minimum Supply. Often, the term “baseload generation” identifies the supply resources that serve this horizontal

slice of baseload demand. Traditionally, these baseload resources consist of coal-fired plants, nuclear plants, and sometimes hydroelectric plants. In this case, the term “baseload” is implying that the plant’s operating characteristics make them operate at the lowest cost levels when they can operate around the clock. More specifically, traditional sources of baseload generation include:

- Coal-fired plants that typically are turned on to operate above their “minimum generation” level of output and often at their full capability. They have a high cost of shutting down and re-starting, which means owners prefer not to turn them on and off because of the high cost of doing so;
- Nuclear plants that typically operate at their full capabilities whenever they are available, because the shut-down and start-up processes are very costly;
- Some run-of-river hydroelectric generation that operates whenever water is available.³

³ In some cases hydroelectric facilities must operate to meet environmental, wildlife, agricultural, and/or recreational needs.

Since portfolios of other supply (and demand) types of resource can serve or help to serve minimum demand; there is no special reason for minimum demand to be served in horizontal slices by individual generating units. In fact, traditional “baseload” generation does not actually serve a full horizontal slice of demand. They experience unexpected outages (as all generators do) and they go on extended maintenance outages. While traditional baseload resources are on outage, other resources on the system fill the gaps to serve minimum load.

Price-Takers. Within a wholesale market setting, “baseload” has been used sometimes to describe resources that offer as “price-takers” into the energy markets, which means they are selected first to run. The term “price-takers” is applied to these units because they prefer to operate regardless of market prices (*i.e.*, even if very low). This price-taker concept is rooted in the economics of power plants with a combination of: (a) low variable costs and (b) high start-up and shut-down costs. Historically, it has been best to keep these plants running whenever available, in both market settings *and* resource planning assumptions. However, in today’s industry, some of these traditional “baseload” generators can no longer operate profitably as price-takers. Aging coal plants are relatively less efficient than newer, more efficient, plants and so that degrades some cost advantages. Since 2008, the variable fuel cost of natural gas-fired generation in some parts of the U.S has been persistently low compared to that of coal. Combined with improved operational efficiencies in the natural gas fleet, this has made a significant amount of natural gas-fired generation more economical to operate than some coal-fired generation. In addition, since the mid-2000s, economic changes, energy efficiency investments, and customers’ conservation efforts have reduced load growth; and renewable energy investments have added a significant amount of resources with almost zero operating costs. Today, in both market and utility-operational settings, these industry trends have significantly reduced the need for traditional “baseload” resources.

Reliable Supply. At times, the term “baseload” has been associated with resources that “reliably” generate twenty-four hours a day, seven days a week. This operational association carries with it several misconceptions, which has led some to mistakenly conclude that the development and maintenance of traditional “baseload” generation is essential to ensuring reliable power supply. In reality, “baseload” is not a service or attribute *per se*, and it is not equivalent to the more clearly, technically-defined concept of reliability.

Is Onsite Fuel a Valuable Service?

Not necessarily. Reliability of fuel supply is a better-defined need and resource service, and reliable fuel supply can be achieved in many ways, including through backup fuel supply.

It is a misconception that “baseload” plants (or any plants, for that matter) are 100% reliable. Coal and nuclear plants periodically go on outage, and when they do, their outages tend to be long. System planners and operators plan around those outages to ensure that there is sufficient supply on the system to keep the lights on even when those large generators are experiencing outages. For instance, maintenance outages for coal and nuclear generating units last for weeks at a time, usually in the spring or fall, and system operators tend to schedule those outages in a way to minimize reliability problems on the system.

Further, unexpected coal and nuclear generating unit outages are sometimes the “largest contingencies” for which system planners and operators must prepare, and thus, many system investments are made to mitigate the potential system impacts of these contingencies.⁴ No generating plants operate 100% reliably in all hours of the year. All generators are prone to occasional unexpected outages and must regularly go offline for maintenance outages. To ensure reliable power supply, planners and operators utilize a portfolio of system resources.

Electricity customers rely on the grid to provide power whenever needed, in all hours of the day and night. From an electric customer’s perspective, a reliable source of power does not have to come from the same power plant in all or most of those hours. Reliable power supply always comes from a portfolio of resources, and it never comes from a single generating unit. In power markets and utility operations, a generating unit typically is committed and dispatched to run at full output in all hours of the day only when it is economical to do so, not because it is a prerequisite for system reliability.⁵ The same level of generation, for example, can be met through a combination of variable wind or solar resources and flexible natural gas-fired resources or storage. Similarly, regional system planning requires no single “match” of resources; resources can be combined in a number of ways to ensure that at any given time supply meets demand. Good planning ensures that a portfolio of resources with a range of costs and operational characteristics is available to provide the most efficient mix of resources to reliably meet demand.

Most “baseload” generation facilities have significant limits to providing flexibility-related reliability services, both technically and economically. They typically have relatively slow ramping up/ramping down rates, high minimum generation limits, and/or long and expensive start-up and shut-down processes. Many nuclear and coal units operate most economically when they can avoid frequent startups and shutdowns and generate continuously in most hours of the year. Operational flexibility is becoming an increasingly important reliability service, as we discuss later in this report.

II. An Evolving Grid

In the past decade or so, several power industry trends have affected the economics of traditional baseload supply. Low natural gas prices, changes in electricity consumption, declining costs of renewables, capital expenditures to comply with environmental regulations and maintain aging plants, partial internalization of GHG emissions in some parts of the U.S., and the growing

⁴ For example, see discussion in Lawrence Berkeley National Laboratory, *Loads Providing Ancillary Services: Review of International Experience*, May, 2007, available at https://www.energy.gov/sites/prod/files/oeprod/DocumentsandMedia/Loads_providing_Ancillary_Services_main_report_62701.pdf

⁵ At times, generation resources need to be operating to support the local reliability of the transmission grid. However, such “must-run” resources are often neither low-cost nor traditional baseload resources.

customer preferences for clean-energy and distributed resources—are all drivers affecting the economics of traditional “baseload” generation. These changes mean that the concept and role of the term “baseload” is becoming less useful for identifying cost-effective supply mix options. At the same time that the relevance of baseload has been declining, there is a growing need for flexible resources and the industry is turning its attention towards defining and meeting today’s flexibility needs.

A. TRENDS IN THE POWER INDUSTRY AND CUSTOMER PREFERENCES

Several trends in the power industry affect the relative economics and value of coal and nuclear generation compared to other system resources.

Low Natural Gas Prices. Sustained low natural gas prices since 2008 have made natural gas-fired generation more economical than coal-fired generation in many regions of North America. Low natural gas prices have driven down wholesale electricity market prices across the country, affecting the market revenues and energy value of all generation resources.

Changes in Electricity Consumption. Reduced growth in electricity consumption, in part due to changing economic conditions, customers’ conservation efforts, more efficient buildings and appliances from stronger codes and standards, and utilities’ efficiency and load management programs, has tempered the need to maintain or extend the lives of aging generators. This decline in load growth has affected some areas more than others. Increased customer preferences for and access to conservation and clean energy—such as through voluntary green energy programs or rooftop solar generation—has further reduced the need for power supply from “baseload” generation.

Looking forward, these declines in electricity consumption may be partially offset by increased electrification of transportation and heating to meet environmental and/or cost savings objectives. But such electrification would likely bring new storage and demand-side resources to the grid that would help grid operators balance supply and demand cost-effectively. Other technological and business model initiatives allow customers and electric utilities to better monitor and control electricity usage when needed, and better optimize customer usage patterns in harmony with the rest of the grid. For example, in 2014, the Energy Information Agency estimated that 41% of all customer meters were advanced meters, and that number continues to grow.^{6,7} Innovations in technology and consumer product development, such as smart thermostats, are a preview of the smart appliances and smart homes of the future.

⁶ Federal Energy Regulatory Commission, *Assessment of Demand Response and Advanced Metering*, Staff Report, December, 2016, available at <https://www.ferc.gov/legal/staff-reports/2016/DR-AM-Report2016.pdf>

⁷ U.S. Energy Information Administration, *Frequently Asked Questions: How many smart meters are installed in the United States, and who has them?*, webpage updated on December 7, 2016, <https://www.eia.gov/tools/faqs/faq.php?id=108&t=3>. Last accessed June 2017.

Declining Costs of Renewables. Wind and solar generation has emerged as a low-cost source of clean energy. Wind generation technologies have improved and capital costs have decreased dramatically over the past several decades. In the wind-rich states, such as North Dakota, South Dakota, Nebraska, Kansas, Oklahoma, and Texas, onshore wind capacity factors can reach as high as 55%.⁸ In some cases, wind project developers are expecting even higher capacity factors. On a \$/MWh basis, the all-in levelized costs of wind plants in these areas are near or below that of traditional fossil-fired generators, even before considering federal tax credits, renewable energy credits, or a value on GHG abatement.⁹ In more recent years, the capital costs of photovoltaic (PV) solar generation technologies (both utility-scale and distributed) have declined significantly, and in solar-rich states like California, Arizona, and New Mexico, capacity factors can reach as high as 30%.¹⁰ These solar technologies are quickly approaching costs that make them economical in many areas even before accounting for federal tax credits, renewable energy credits, or a value on GHG abatement. The fact that, even before considering these factors, renewables technologies are now cost competitive with conventional generation technologies in many regions of the country is now broadly recognized across the industry, including by financial institutions that finance both conventional and renewable generation investments.¹¹

Capital Expenditures to Comply with Environmental Regulations and Maintain Aging Plants.

Major investments in emissions control equipment at coal-fired power plants have been required by strengthened air quality standards, such as the Environmental Protection Agency’s recently-implemented Mercury and Air Toxics Standards (MATS). State-implemented water cooling regulations will also impact some nuclear plants, but to a lesser extent. In addition, much of the coal and nuclear fleet is over 40 years old and requires major maintenance and investments to continue operations.

(Partial) Internalization of the Costs of Greenhouse Gas Emissions. There has been broad recognition that the electricity sector is pivotal for reducing economy-wide GHG emissions, both in terms of emissions from power plants and in terms of electrifying transportation and other sectors. In 2015, for example, the Environmental Protection Agency estimated that 29% of

⁸ Alexander E. MacDonald, Christopher T.M. Clack, *et al.*, “Future cost-competitive electricity systems and their impact on US CO₂ emissions,” *Nature Climate Change* (January 25, 2016): DOI: 10.1038/NCLIMATE2921.

⁹ Lawrence Berkeley National Laboratory, *2015 Wind Technologies Market Report*, August 2016, available at <https://emp.lbl.gov/publications/2015-wind-technologies-market-report>

¹⁰ Alexander E. MacDonald, Christopher T.M. Clack, *et al.*, “Future cost-competitive electricity systems and their impact on US CO₂ emissions,” *Nature Climate Change* (January 25, 2016): DOI: 10.1038/NCLIMATE2921.

¹¹ Lazard, *Lazard’s Levelized Cost of Energy Analysis— Version 10.0*, December 2016, available at <https://www.lazard.com/perspective/levelized-cost-of-energy-analysis-100/>

economy-wide GHGs were produced by the electric industry and 27% from transportation.¹² State and local policies articulating GHG reduction goals, renewables portfolio standards, electrification, and other environmental initiatives have become major drivers for a shift towards a cleaner electricity supply mix. Many states and localities have made considerable commitments on reducing GHG emissions, even absent a clear federal policy. New York State, for example, launched its Reforming the Energy Vision (REV) initiative in 2014, which supports the state's goal of 40% reduction in economy-wide GHG emissions by 2030 (relative to 1990 levels) and 80% reduction by 2050.¹³ The New England states Massachusetts, Connecticut, and Rhode Island similarly have statutory long-term goals to reduce GHG emissions by 80% by 2050, along with forward-looking energy strategies and policies (such as Renewable Portfolio Standards and energy efficiency programs) to support those goals.¹⁴ In 2017 New York, California, and Washington formed a climate alliance, with a mission to uphold the goals of the Paris climate agreement.¹⁵ Shortly thereafter, nine additional states plus Puerto Rico joined the alliance.¹⁶ At the same time, increased regulatory stringency has better internalized public health impacts related to mercury and air toxics, criteria air pollutants, water usage, coal ash waste disposal, and land use for all power plants. Finally, many utilities are recognizing the likelihood of GHG regulations in the future by assuming future prices for carbon emissions in their resource plans.¹⁷

Customers' Shift to Clean Energy. Some electricity users, large and small, are shifting their procurement to reflect their preference for clean-energy resources. Most of this shift is the result of significant renewable technology cost reduction over the past few years. Many businesses

¹² U.S. Environmental Protection Agency, Greenhouse Gas Emission, Sources of Greenhouse Gas Emissions, available at <https://www.epa.gov/ghgemissions/sources-greenhouse-gas-emissions>. Last accessed June 2017.

¹³ New York State, "Reforming the Energy Vision, REV", February 2016, available at <https://www.ny.gov/sites/ny.gov/files/atoms/files/REV42616WHATYOUNEEDTOKNOW.pdf>

¹⁴ ISO Newswire, "The New England states have an ongoing framework for reducing greenhouse gas emissions", March 1, 2017, available at <http://isonewswire.com/updates/2017/3/1/the-new-england-states-have-an-ongoing-framework-for-reducin.html>. Last accessed June 2017.

¹⁵ "New York Governor Cuomo, California Governor Brown, and Washington Governor Inslee Announce Formation of United States Climate Alliance," New York State press release, June 1, 2017, available at <http://www.governor.ny.gov/news/new-york-governor-cuomo-california-governor-brown-and-washington-governor-inslee-announce>

¹⁶ "United States Climate Alliance Adds 10 New Members to Coalition Committed to Upholding the Paris Accord," New York State press release, June 5, 2017, available at <https://www.governor.ny.gov/news/united-states-climate-alliance-adds-10-new-members-coalition-committed-upholding-paris-accord>

¹⁷ Joseph Kruger, "Hedging an Uncertain Future: Internal Carbon Prices in the Electric Power Sector," Resources for the Future, April, 2017, available at <http://www.rff.org/files/document/file/RFF-Rpt-Kruger-Internal%20Carbon%20Pricing.pdf>

view cleaner energy sources as a hedge against uncertain wholesale electricity prices, and as a selling point for their commercial image because they perceive that their customers value renewable energy and “green” products and services. In 2015 alone, more than 3,200 MW of voluntary power purchase agreements for renewable energy were signed by commercial and industrial electricity customers. The technology giants Apple, Amazon, Google, and Microsoft have made public commitments to purchasing renewable energy resources. Apple has claimed, for example, that it has used renewable energy to power all of its data centers since 2012. In 2016, Apple announced that 93% of its facilities worldwide run on renewable energy.¹⁸ Also in 2016, a collection of more than sixty companies interested in increasing their purchases of renewable energy set a goal of procuring 60,000 MW of new renewable generation in the U.S. by 2025.^{19,20}

B. CHANGES IN THE ECONOMICS OF TRADITIONAL BASELOAD GENERATION

The economics of traditional “baseload” generation has changed significantly since most of the existing fleet was built in the 1970s and 1980s. Today’s low natural gas prices combined with low load growth, increased renewable generation, and necessary new capital investment and regulatory requirements that better reflect the environmental costs of emissions—have made it much less economical to operate coal-fired generators. In the years 2012–2016, over 40,000 MW of coal plants retired in the U.S.²¹ The main factors were the relatively high cost of operating coal plants compared to natural gas plants in today’s low-priced natural gas market and capital expenditures needed to comply with new air emissions rules. Domestic coal consumption has collapsed due to lower electricity demand (efficiency improvements have kept demand flat since 2009 even as economic growth has rebounded), and the declining cost of renewable energy. A recent study from Columbia University’s Center on Global Energy Policy estimates that cheap natural gas was responsible for 49% of the decline in coal demand, low electricity demand was responsible for 26%, and increased renewable generation was responsible for 18%.²²

¹⁸ Greentech Media, *Apple Now Operates on 93% Renewable Energy Worldwide*, March 22, 2016, available at <https://www.greentechmedia.com/articles/read/Apple-Now-Operates-on-93-Renewable-Energy-Worldwide>

¹⁹ WRI, “RELEASE: Renewable Energy Buyers Alliance Forms to Power the Corporate Movement to Renewable Energy,” WRI Press Release, May 12, 2016, available at <http://www.wri.org/news/2016/05/release-renewable-energy-buyers-alliance-forms-power-corporate-movement-renewable>

²⁰ WRI, “Corporate Renewable Energy Buyers’ Principles: Increasing Access To Renewable Energy,” December 2015, available at http://www.wri.org/sites/default/files/Corporate_Renewable_Energy_Buyers_Principles.pdf

²¹ Based on data compiled by ABB, Inc., *The Velocity Suite*, accessed June 2017.

²² Trevor Houser, Jason Bordoff, and Peter Marsters, *Can Coal Make a Comeback?*, Columbia | SIPA Center on Global Energy Policy, April 2017, available at

The economics of nuclear power plants have also been adversely affected by the same pressures of low natural gas prices, low load growth, and increased renewable generation. Combined with technical and cost challenges associated with the aging fleet and compliance with increasing nuclear safety regulations, many nuclear plants are facing retirement pressures as well. As a result, in the last few years, about 13,000 MW of nuclear retirements were either completed or announced.²³ Several other nuclear units—about 4,000 additional MW—have been identified as “at risk” for retirement based on market conditions and estimates of these units’ going-forward costs.²⁴

In some parts of the country, coal and nuclear plants must periodically operate at considerable loss during off-peak hours to avoid shutting the plants so they can capture revenues during the higher-priced peak hours.

The operational inflexibility to adjust output levels in response to low market prices for some coal and nuclear plants significantly cuts into the plants’ overall profitability. In some hours, these less flexible resources need to operate even when market prices are not enough to cover their variable operating costs. A natural gas-fired combined cycle unit, in contrast, can generate electricity in all hours if necessary but can adjust its output levels or shut down entirely during off-peak hours or weekends when market prices drop below its variable cost of generation.

The PJM market monitor’s annual reports provide some comparisons across different new power generation technologies in the PJM market. The 2016 State of the Market report shows that new entrant natural gas-fired combined cycle plants, combustion turbine plants, and solar are economical, but that new coal and nuclear plants are not.²⁵ The report also shows that revenues earned by *existing* plants have been mostly sufficient to cover the “to-go” costs of gas plants but not for coal plants.

Why are coal and nuclear plants retiring?

- Sustained low natural gas prices and increased competition from existing and new natural gas-fired plants
- Low electricity demand and growth
- Declining renewables costs and competition from new renewable generation
- Aging fleet that requires additional going-forward capital investments
- Capital expenditures to comply environmental and public health regulations
- Some limits in operational flexibility and costly to start-up/shut-down, so must operate through low-priced hours that reduce profitability

Continued from previous page

<http://energypolicy.columbia.edu/sites/default/files/energy/Center%20on%20Global%20Energy%20Policy%20Can%20Coal%20Make%20a%20Comeback%20April%202017.pdf>

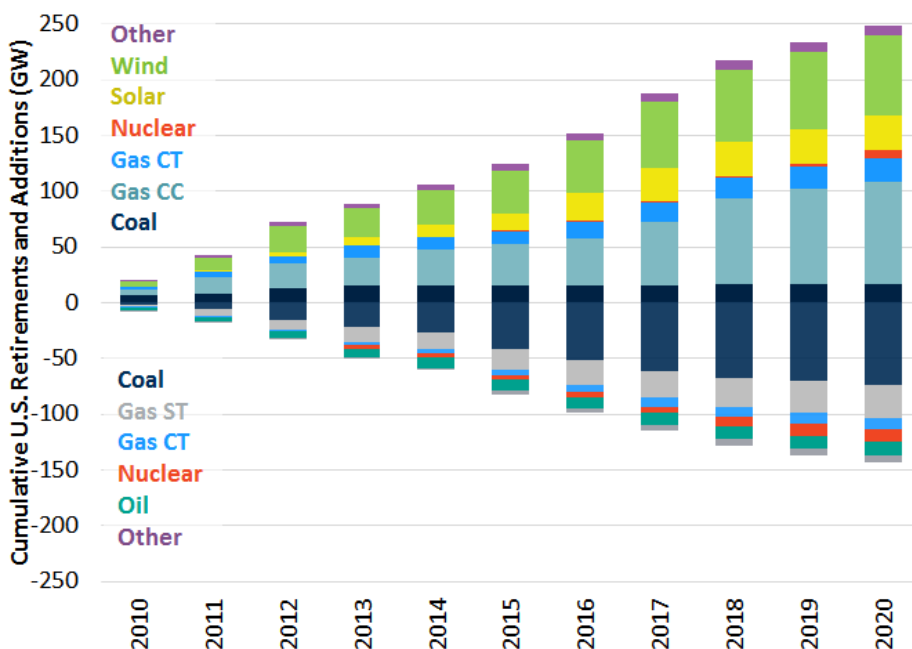
²³ This estimate includes SONGS, Crystal River, Kewaunee, and Vermont Yankee retirements in 2013 and 2014; and Quad Cities, Fort Calhoun, Diablo Canyon, Pilgrim, Clinton, Oyster Creek, Fitzpatrick, and Ginna announced retirements for 2016–2024.

²⁴ This estimate includes Duane Arnold, Fermi, Palisades, and Point Beach.

²⁵ Monitoring Analytics, LLC, *2016 State of the Market Report for PJM*, March 9, 2017, available at http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2016.shtml

Figure 4 below shows the overall U.S. cumulative actual and announced capacity retirements and additions from 2010 through 2020. The bottom half of the graph shows that during this 11-year period, over 70,000 MW of coal capacity will have been retired, and the top half of the graph shows the capacity additions of the various technologies, in particular wind, solar, and natural gas-fired resources.²⁶ Despite these significant retirements and the associated shift resource mix, system operators have been able to meet the industry’s high and increasing reliability standards. PJM, for example, has pointed out that its resource mix has become more balanced over time and that its expected near-term portfolio is among the highest-performing.²⁷

Figure 4: U.S. Cumulative Capacity Retirements and Additions by Fuel Type (GW), 2010–2020



Source and Notes: The Brattle Group analysis of data compiled by ABB, Inc., The Velocity Suite, June 2017. Gigawatts reflect nameplate capacity. Solar additions represent utility-scale solar. Future additions reflect units currently under construction, undergoing site preparation or testing, and permitted.

C. A SHIFT IN THE ROLE OF BASELOAD GENERATION

Some concerns have arisen over the implications of energy from traditional “baseload” plants being replaced with generating sources that do not necessarily operate at full capacity most of the time. This displacement, in particular in combination with the addition of renewable resources,

²⁶ Wind and solar resources typically provide less load-carrying capability, and therefore, less capacity value per megawatt of installed capacity than natural gas-fired combined cycle or combustion turbine units.

²⁷ PJM Interconnection LLC, *PJM’s Evolving Resource Mix and System Reliability*. March 30, 2017, available at <http://www.pjm.com/~media/library/reports-notice/special-reports/20170330-pjms-evolving-resource-mix-and-system-reliability.ashx>

does not seem to fit with the traditional “baseload” paradigm and therefore initiates questions such as: “Can variable resources be counted on for reliability purposes?” or “Aren’t baseload plants needed to maintain reliability?”

To answer these questions, it is important to understand that “baseload” and reliability are two different concepts. Maintaining system reliability does not require power generation from any single generator or a specific group of generators that operate during all hours at full capacity. By defining system reliability needs in more precise terms, system planners and operators can answer these questions. Doing so is leading them to conclude that new vintages of variable resources can contribute to the reliability of the system, and that “baseload” plants are not necessary to maintain system reliability. Further, they are recognizing that asking whether or not baseload is needed is not an important question at the system level. Instead, the important question is, “What services are needed to maintain system reliability, and how should they be valued and planned for?”

Coal and nuclear plants contribute to “resource adequacy” by having generating capacity that can be dispatched to meet system needs. In addition, coal plants can provide some ancillary services, such as regulation and operating reserves.²⁸ Therefore, these resources clearly help maintain system reliability. However, they are not the only technologies that provide such reliability-related services. Below are the three broad classes of reliability services that system planners and market operators need to acquire—in some cases through the wholesale power markets. These services (and the extent to which these services can be provided by nuclear and coal plants) include:

- **Resource Adequacy** is the availability of generating resources that can be used to meet peak load, taking into account the possibility of outages for some of a system’s generation fleet. Traditional “baseload” generation provides available capacity during peak hours and during system events and emergencies, but other supply technologies can provide that too. In PJM’s capacity market, for example, resource adequacy is provided by a diverse portfolio of resources, including existing nuclear and coal plants, new natural gas-fired generators, energy efficiency, demand response, solar, wind, and fuel cells.^{29,30} Most of the newer technologies are able to respond to system emergencies more quickly than the fleet of existing nuclear and coal plants, particularly when the response requires the units to start up.
- **Regulation and Frequency Control** are used to match generation and load on a moment-by-moment basis to maintain electrical frequency and system-wide stability. Some may

²⁸ Ancillary services are products used by system operators and grid managers to support system reliability through real-time operational flexibility and other system services.

²⁹ PJM Interconnection LLC, *2019/2020 RPM Base Residual Auction Results*, Capacity Market (RPM), available at <http://www.pjm.com/markets-and-operations/rpm.aspx>

³⁰ A capacity market compensates resources for contributing to resource adequacy on the system.

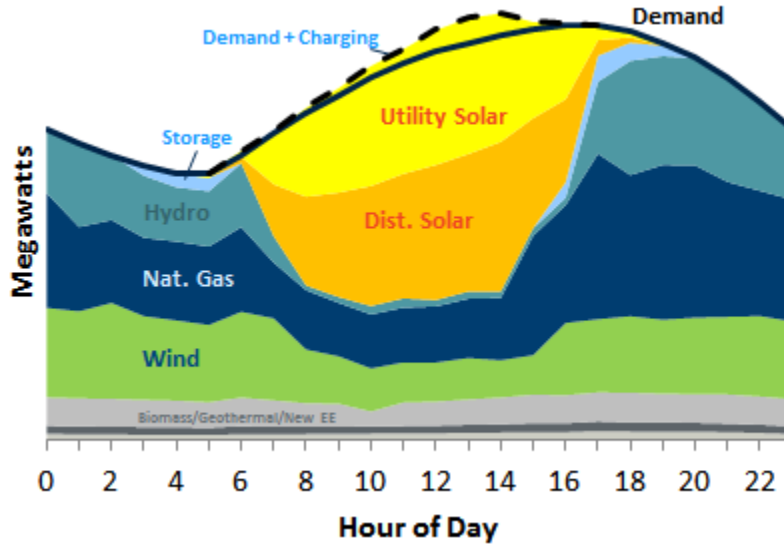
argue that nuclear and coal plants provide valuable spinning mass that the grid needs to control frequency. As a result, they argue that shutting these plants down would pose a reliability problem. However, natural gas-fired combined cycle units provide very similar levels of inertia, and new converter technology can supply synthetic inertia from wind plants. Natural gas plants also provide very similar levels of regulation capability as coal plants, and significantly more than nuclear plants. Inverter-based technologies, such as batteries, and solar and wind plants, can provide high-quality frequency response and regulation services.

- **Operating Reserves** is generating capacity held on stand-by that can be dispatched within 10 minutes in response to unexpected load spikes or generation outages. When operating at less than full capacity, coal plants can provide operating reserves, in particular spinning reserves. Other technologies, such as natural gas plants and storage, can provide operating reserves as well. Newer natural gas-fired plants are particularly flexible, with the capability to provide the full range of reserves, including non-spinning reserves that can start up within 10–30 minutes, that grid operators need use to support system reliability.

Trends in the power industry and changes in the economics of traditional baseload supply have altered the planning and operational paradigm that was once focused on slicing demand and supply into the “baseload,” “intermediate,” and “peaking” categories. Figure 5 below is a conceptual depiction of a day’s hourly demand and supply in a high renewables penetration system, roughly based on a California-like future. As shown, much of the supply mix for meeting needs includes clean energy resources, and these resources clearly contribute to resource adequacy. In such a system, solar generation reduces the need for other types of generation during the day, including the need for baseload power plants. During those hours, many other resources, such as natural gas-fired combined cycle and combustion turbine units, some hydro and demand response, are available and capable of producing higher levels of electricity, but they are dialed back (to the extent they can be) to ensure that solar and wind resources with almost zero variable costs are used to the maximum amount possible. This illustration of a California-like future represents an example of the economical operation of a system that is both clean and reliable.

The modern supply mix is really a complementary mix of variable resources that provide least-cost energy and environmental attributes, and flexible resources that provide low-cost energy and operational flexibility.

Figure 5: Illustration of Electricity Demand and Supply Mix with High Renewables Penetration



Source: The Brattle Group.

As the figure shows, the available resources that can provide operational flexibility to ramp up during off-peak hours and ramp down during on-peak hours are important and valuable. They include flexible hydro, natural gas-fired combined-cycle and combustion turbine units, and storage (that provide electricity stored from another period). This supply portfolio reflects a mix of variable resources that provide cost-effective energy and environmental attributes, complemented by resources that provide both low-cost energy and operational flexibility.

Some note that coal and nuclear plants provide resiliency to our electricity grid because they store fuel on site, which can insure against fuel supply interruptions. While having onsite fuel storage or backup fuel is desirable for all generating facilities, it does not always assure availability, as recent experience has demonstrated. For example, during a February 2011 cold weather event, 20,000 MW of coal- and natural gas-fired plants unexpectedly shut down in the Southwest (including the Electric Reliability Council of Texas (ERCOT) footprint) because of frozen equipment and other cold-weather related problems for which they were not prepared.³¹ Even in areas used to cold winters, like Pennsylvania and Wisconsin, exceptionally cold temperatures have led to frozen coal piles, and oil barges stuck on frozen rivers, which prevented coal plants from turning on.³²

³¹ Federal Energy Regulatory Commission and North American Electric Reliability Corporation, *Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1–5, 2011*, Staff report, August, 2011, available at <https://www.ferc.gov/legal/staff-reports/08-16-11-report.pdf>

³² Amory B. Lovins, “Does ‘Fuel on Hand’ Make Coal and Nuclear Power Plants More Valuable?,” *Forbes*, May 1, 2017, available at <https://www.forbes.com/sites/amorylovins/2017/05/01/does-fuel-on-hand-make-coal-and-nuclear-power-plants-more-valuable/3/#73ec4b693473>

While on-site fuel storage can increase the availability of a plant, it is not unique to coal plants (with fuel stored in coal piles) and nuclear plants (with energy stored in the reactor's fuel rods). Natural gas plants, for example, routinely have backup fuel systems, such as stored on-site fuel-oil or access to liquid natural gas (LNG) facilities or alternative pipelines, to assure plant availability in the case of pipeline gas interruptions.

Wind and solar resources do not consume fuel and therefore they do not require any on-site fuel storage. While their production does depend on the availability of sun or wind, they can nevertheless contribute to system reliability, providing needed production when fuel supplies of other resources are interrupted. A few experiences demonstrate this fact. During the 2011 cold snap in Texas, approximately 7,000 MW of fossil-fueled plants were unable to generate electricity while wind resources generated about 3,500 MW during the morning peak, which helped to keep the lights on.³³ Similarly, during the 2014 "Polar Vortex," when many coal and gas resources had difficulties generating power, wind resources' in the Midwest consistently produced power that helped to save electricity customers more than \$1 billion in two days.³⁴ In Texas, the generation output from coastal wind plants is highly correlated with afternoon peak loads, which significantly contributes to ERCOT's resource adequacy needs.

There are many ways a generator can improve fuel supply reliability, such as through firmer fuel contracts and dual fuel capability. This has been a topic of study for some RTOs that have explored market-based solutions for incentivizing generating unit-level reliability. While onsite fuel storage can contribute to generator availability in many circumstances, it does not guarantee reliability in all scenarios.

D. THE EMERGING NEED FOR FLEXIBLE RESOURCES AS PART OF A MORE OPTIMAL SUPPLY MIX

Efficient and operationally-flexible resources, combined with low-cost wind and solar generation, provide planners and operators with the opportunity to build a reliable and cost-effective supply mix for meeting modern system and environmental needs. Flexible resources help to integrate variable renewable resources and to access the energy and environmental benefits of wind and solar generation. They can dynamically adjust their operating levels in response to changing system conditions, such as variations in demand, variations in renewable

³³ Trip Doggett, CEO of ERCOT, stated "I would highlight that we put out a special word of thanks to the wind community because they did contribute significantly through this time frame. Wind was blowing, and we had often 3,500 megawatts of wind generation during that morning peak, which certainly helped us in this situation." Kate Galbraith, "Trip Doggett: The TT Interview", *The Texas Tribune*, February 4, 2011, available at <https://www.texastribune.org/2011/02/04/an-interview-with-the-ceo-of-the-texas-grid/>

³⁴ AWEA, "Wind generation sets records, saves consumers money as extreme cold grips nation," news release, January 7, 2015, available at <http://www.awea.org/MediaCenter/pressrelease.aspx?ItemNumber=7088>

generation, extreme weather conditions, and system emergencies. Some flexible resources can contribute to longer-term adaptability of the existing power system as the grid evolves. For example, as the use of electric vehicles increases, the electricity supply mix may need to adapt to a variety of electric vehicle charging patterns. Flexible resources within the system help integrate such new technologies. Thus, the increasing desirability of flexible resources is driven not only by the addition of variable wind and solar generation, but reflects technological changes of the modern system, the evolving needs of the economy as a whole, and a dynamic and robust grid.

Over the past decade, much of the operational needs associated with variable wind and solar generation have been addressed by technological, operational, and market innovations. For example, improving wind and solar forecasts have reduced balancing-related challenges during real-time operations and reduced system-wide costs because grid operators can rely on more accurate forecasts of wind and solar output when committing and dispatching generators in the day before the actual operating hours.³⁵ Other technological innovations, such as fast-acting grid-scale battery storage technologies, have helped reduce system-balancing costs and increase reliability beyond what has previously been possible with conventional generating resources. Innovations in wholesale power market design by the regional grid operator similarly provide improved price signals and incentives to better utilize the latent flexibility of the existing grid and resources, often making it possible to add improved control systems to make existing plants more flexible and more valuable.

Many industry studies have concluded that technological and grid management innovations have made high renewables penetration operationally feasible. For example, the National Renewable Energy Laboratory (NREL) has led major studies on renewables integration, including a 2010 study focusing on the western U.S. system, and a 2016 study focusing on the eastern U.S. system. The western integration study concluded that 35% wind and solar penetration could be managed simply with changes to operational practices, and would not require extensive infrastructure changes.³⁶ The eastern integration study concluded that 30% renewable penetration is technically feasible with the existing grid, but would require coordinated system operations

³⁵ The National Center for Atmospheric Research (NCAR) helped develop a new forecasting system (Sun4Cast) that improves solar forecasting. The new forecasting system has been estimated to lead to savings of \$455 million through 2040 with the increased integration of solar resources. NCAR UCAR Atmos News, “Solar Energy Gets Boost from New Forecasting System: More accurate forecasts could save hundreds of millions of dollars,” New Releases, August 23, 2016, available at <https://www2.ucar.edu/atmosnews/news/122429/solar-energy-gets-boost-new-forecasting-system>

³⁶ GE Energy, *Western Wind and Solar Integration Study*, prepared for the National Renewable Energy Laboratory, May, 2010, available at <https://www.nrel.gov/grid/wwsis.html>

across neighboring regional markets.³⁷ Over a longer planning horizon, NREL found that 80–90% percent renewable generation is feasible by 2050.³⁸

With better understanding of system requirements, flexibility needs can be provided by a wide array of existing resources, and through advances in how those resources are operated. Depending on the region and the extent of renewable deployment, additional resources may be needed to provide certain types of operational flexibility. The California Independent System Operator’s (CAISO) 2016 report on resource flexibility, for example, discusses how flexibility needs are increasingly involving shorter time scales. The study looked at three time scales: (1) seconds-to-minutes, (2) 5–10 minutes, and (3) multi-hour. CAISO found that the need for 3-hour ramping capacity increased significantly over the 2015–2017 timeframe.³⁹ The study also described a wide range of existing resources that can provide the required flexibility, including existing natural gas-fired capacity, geothermal, hydroelectric and pumped storage, biomass, oil-fired peaking units, solar, and demand response resources. Similarly, a joint renewable integration study by PJM and General Electric concluded in part that 30% renewables penetration would not create any operational issues within the PJM footprint.⁴⁰ To mobilize the latent flexibility of the existing grid, the study recommended some refinements to PJM’s regulation requirement calculations, refinements to renewable capacity valuation methodology in the capacity market, improvements to wind and solar forecasts and their use in operations software, and an investigation of methods for improving ramping rates in the baseload generation fleet. These findings are consistent with the Southwest Power Pool’s (SPP’s) recent wind integration study, which found that, due to its improved wholesale market design, the grid operator’s existing system can manage wind penetrations of up to 60%.⁴¹

As more renewable resources are added to the regional systems, better inter-regional coordination in planning and system operations can help to address wind and solar variability. Coordinated operations over a larger geographic footprint can reduce variability through natural geographic resource diversity. Borrowing from European experience, for example, in a 2015 study, the French utility Électricité de France (EDF) analyzed a future scenario assuming 40% wind and solar penetration and found that geographic diversity significantly reduces the

³⁷ Aaron Bloom, Aaron Townsend, *et al.*, *Eastern Renewable Generation Integration Study*, National Renewable Energy Laboratory, August 2016, available at <https://www.nrel.gov/grid/ergis.html>

³⁸ T. Mai, D. Sandor, R. Wisler, and T. Schneider, *Renewable Electricity Futures Study: Executive Summary*, NREL/TP-6A20-52409-ES, Golden, CO: National Renewable Energy Laboratory, 2012.

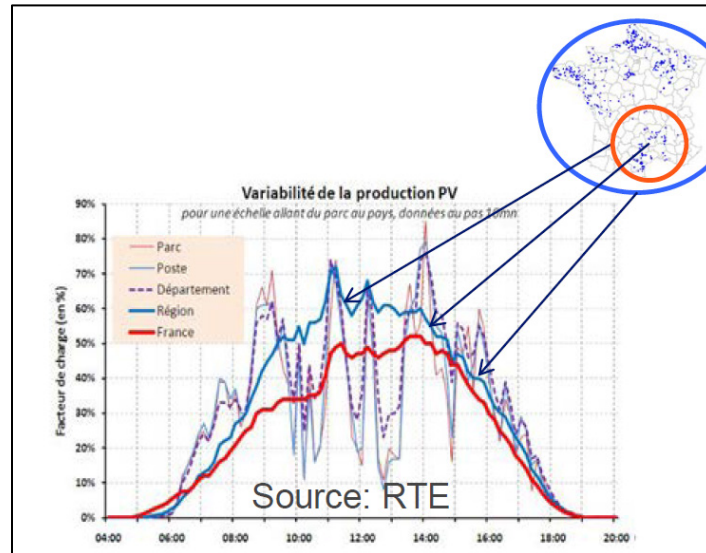
³⁹ See California Energy Commission—Tracking Progress, Resource Flexibility, December 15, 2016, p. 5, available at http://www.energy.ca.gov/renewables/tracking_progress/documents/resource_flexibility.pdf

⁴⁰ PJM Interconnection LLC, Renewable Integration Study Reports, available at <http://www.pjm.com/committees-and-groups/subcommittees/irs/pris.aspx>

⁴¹ Southwest Power Pool, 2016 Wind Integration Study, January 5, 2016, available at [https://www.spp.org/documents/34200/2016%20wind%20integration%20study%20\(wis\)%20final.pdf](https://www.spp.org/documents/34200/2016%20wind%20integration%20study%20(wis)%20final.pdf)

variability in total output of these resources at a system level. Figure 6 below demonstrates EDF’s analysis of solar PV output levels for different geographical areas in France, including local area (“département” in the figure), regional, and country-wide. The graph shows that overall, when resources across different locations are considered across a sufficiently large system, the diverse generation profile significantly mitigates the need for additional balancing resources on the system.

Figure 6: Solar PV Generation for Different Geographical Areas in France



Source: Zulueta, Miguel Lopez-Botet and Vera Silva, *Électricité de France R&D, Economic and Technical Analysis of the European System with a High RES Scenario*, November 24, 2015, available at https://energiforskmedia.blob.core.windows.net/media/21040/4_edf_lopez_botet_zulueta.pdf.

In 2016, the CAISO conducted a study on the benefits of broader coordinated regional day-ahead operations and markets within the Western Electricity Coordinating Council (WECC) footprint.⁴² One future scenario assumed enough renewable development to meet each state’s renewables portfolio standards, including California’s requirement of 50% by 2030, met mostly by wind and solar resources. The study demonstrated that coordinated operations and markets across the larger WECC footprint could enable more efficient use of the grid’s existing flexibility.

⁴² California ISO, The Brattle Group, Energy and Environmental Economics, Inc., Aspen Environmental Group, and Berkeley Economic Advising and Research, *Senate Bill 350 Study: The Impacts of a Regional ISO-Operated Power Market on California*, July 8, 2016, available at <https://www.caiso.com/informed/Pages/RegionalEnergyMarket.aspx>

III. Advances for Meeting Grid's Flexibility Needs

Whether through resource planning or through market operations, many state policymakers and grid operators are recognizing that the cost and technology characteristics of supply are changing, system needs are evolving, and traditional methods of ensuring reliability must adapt to these changes. In particular, meeting the grid's increasing flexibility needs will require that utilities, system planners, policymakers, and market designers develop approaches that:

- Better define flexibility needs to support reliability objectives;
- Enable all existing resources that can provide flexibility to do so, whether in a regulated or market setting;
- Attract suppliers who can provide innovative and cost-effective flexibility solutions.

Finding cost-effective ways to integrate renewable resources has been a major driver of increased coordination in operations and markets—such as the expansion of the Energy Imbalance Market (EIM) in the western U.S., the exploration of a western U.S. regional RTO (such as expanding the California ISO or forming a Mountain West market), and various reforms of existing markets. Increased coordination of system operations and market design is expected to yield significant benefits to customers, including lower production and lower investment costs of developing new resources. The estimated benefits of the western EIM—which reflects, in part, an effort to integrate renewable generation more cost effectively—reached \$174 million since its creation in November 2014. There are also benefits with replacing fossil energy with surplus energy from renewable resources. In the first quarter of 2017 alone, the EIM displaced 22,500 metric tons of emissions.⁴³

A. FLEXIBILITY AS A NEW DIMENSION OF PLANNING RESERVES FOR RESOURCE ADEQUACY

Traditional planning for resource adequacy in power supply has focused on building enough generation capacity to meet system peak plus a reserve margin (usually around 15%) to account for uncertainties in load levels, generator availability, and other system conditions. Under this framework, all generating capacities available at system peak are treated approximately as equally contributing to resources adequacy and thus reliable supply under system peak conditions. This framework relied on the idea that any generating unit could theoretically provide maximum output in almost any hour of the year, adjusted for the assumed prevalence of forced outages.

Advanced system planning studies increasingly conclude that flexibility challenges arise when integrating a growing amount of variable generation in systems with large baseload generators that cannot easily or economically ramp their generation output up or down in response to system needs. This combination of variable and inflexible capacity can shift resource adequacy

⁴³ California ISO, *Western EIM Benefits Report, First Quarter 2017*, May 1, 2017, p. 3, available at https://www.caiso.com/Documents/ISO-EIMBenefitsReportQ1_2017.pdf

concerns from hours of system peak demand to periods when the need for flexible resources exceeds the ramping capability of the combined system. For example, Astrape Consulting has analyzed these emerging resource adequacy needs in their analyses of the California wholesale market as well as the single-utility system operated by PNM. For California, this analysis showed that loss of load events (LOLEs) due to a lack of system flexibility is expected to be twice as high as LOLEs due to lack of generation capacity during peak load conditions.⁴⁴ Astrape tested six different scenarios and found that as flexibility increases, reliability improves, and both production costs and emissions decrease.⁴⁵ Astrape reached a very similar conclusion in their analysis of PNM's future system needs, finding that by 2021–2024 the resource adequacy need to address LOLEs is increasingly driven by flexibility requirements (in addition to the capacity necessary to meet peak loads).⁴⁶ The PNM study shows that increasing the flexibility and load-following capability of the utility's system improves system reliability and reduces the need to occasionally curtail customer loads and renewable generation.

In 2016, SPP published its 2016 Wind Integration Study, which concluded that the RTO can reliably manage up to 60% of wind penetration with their current resource mix, given the high level of re-dispatch flexibility under their recently-implemented market redesigns and transmission investments. Even though SPP found that wind curtailments increased as the percentage of wind penetration increased from 30% to 60%, it concluded that system reliability would not be compromised.⁴⁷ As an example of operational improvement, SPP now allows variable energy resources to participate as dispatchable resources in energy markets, which reduced wind curtailments in their high-wind penetration scenarios.

Studies like these provide a path forward for adapting reliability assessments to the modern grid, by developing insights into issues such as:

- The nature of flexibility needs under a variety of future system conditions;
- Growth in flexibility-driven events over time;
- How best to define ancillary services products and system requirements to fully utilize the latent flexibility of the existing grid and its resources;
- Allow and facilitate the provision of ancillary services from types of supply and demand-side resources that can provide these services.

⁴⁴ Astrape, *Flexibility Metrics and Standards Project—a California Energy Systems for the 21st Century (CES-21) Project*, January 6, 2016, available at <http://www.astrape.com/?ddownload=6826>

⁴⁵ *Id.*, slide 16.

⁴⁶ Astrape, *PNM Preliminary Reliability Analysis*, April 18, 2017, available at <https://www.pnm.com/documents/396023/3306887/04182017-irp-mtg-reliability/66b6bdc0-d9d4-4f72-b1dc-076d8c5c74c2>

⁴⁷ Southwest Power Pool, *2016 Wind Integration Study*, January 5, 2016, available at [https://www.spp.org/documents/34200/2016%20wind%20integration%20study%20\(wis\)%20final.pdf](https://www.spp.org/documents/34200/2016%20wind%20integration%20study%20(wis)%20final.pdf).

B. CREATING INCENTIVES FOR FLEXIBILITY IN THE OPERATIONS TIMEFRAME AND IN CENTRALIZED MARKETS

System operators have to balance the power system such that customers' electricity demands can be met by supply at all times. This requires system operators to draw on resources in the system to provide a variety of electricity-related products and services in the most cost-effective manner feasible. In some hours, the system operator may face supply constraints and must determine the best use of resources available in those instances. If necessary, under these conditions, the operator will call upon system emergency procedures, which may include activating quick-start peaking units, calling on emergency demand response resources, and even shedding some system loads. During such constrained and emergency periods, it is critical that all resources be provided with the appropriate incentives to be available to produce power and provide other system services.

In RTO or ISO-operated wholesale power markets, for example, one incentive mechanism for resource availability during constrained hours is the use of scarcity pricing.⁴⁸ RTOs and ISOs also use other market mechanisms, such as a variety of ancillary services markets, in tandem with scarcity pricing to ensure enough resources are available at the right locations to meet customer demand. Similarly, a system-wide resource adequacy mechanism is typically in place to ensure that generators have sufficient opportunities to earn market-based revenues to support the investments in resources that the system needs over time. As system operators and planners consider how customers' preferences and resource mixes change over time, they are working toward modernizing the resource adequacy constructs to evolve with those changes.

Customers and load-serving entities in centralized markets depend on market administrators to provide the proper incentives to resources to provide the necessary services in a cost-effective manner. The market designs for centralized wholesale markets in the U.S. are quite sophisticated and evolving to provide the necessary incentives to a broad range of resources that can contribute to system reliability. As the market designs evolve with system needs, RTOs and ISOs (along with their stakeholders) have analyzed and implemented many innovative approaches to improving market design features, such as scarcity pricing in energy markets, capacity market design improvements, ancillary services reforms, energy and ancillary services co-optimization, integration of demand-response and distributed resources into wholesale market constructs, and improved scheduling of transactions with neighboring markets.

Another growing operational challenge has been the management of “oversupply” or “surplus generation.” These conditions occur when the total power generated is expected to exceed demand levels and generators cannot sufficiently reduce their output. As a result of such oversupply conditions, some energy markets have been witnessing negative prices in their wholesale power markets.

⁴⁸ Scarcity, or shortage, pricing is a market-based construct for incentivizing resources to produce energy or provide system services when the system is extremely constrained.

The negative prices, observed mostly during real-time market operations, are an artifact of the system not being flexible enough to absorb the power that is generated. This lack of flexibility is a result of: (a) producing more power in places where very little customer demand exists; (b) not having sufficient transmission to transfer the generation oversupplied to other parts of the system; (c) not having resources able to easily reduce their power output to maintain the secure and reliable operation of the grid. Negative prices occur when generators are unwilling to incur the costs of shutting down their facilities to reduce supply. Traditionally, coal and nuclear plants would offer some of their energy at negative prices so that they will not be asked to shut down their generating units. Rather, they prefer to pay the negative market price to avoid the cost of shutting down their plant. In recent years, renewable generators (or their contractual counterparts) will offer power at negative prices to avoid curtailments, which would cause them to lose tax incentives or the value of the environmental attributes associated with renewable energy production.

While some industry observers and market participants point to such negative prices as evidence of how renewable generation reduces the profitability of the traditional “baseload” generators, negative prices have only a very modest impact on generator profitability. This is because negative prices mostly occur only in the real-time energy imbalance market, which settles imbalances relative to day-ahead schedules. Negative prices are very rare in day-ahead markets, which provide about 95% of conventional generators’ energy market revenues.⁴⁹

Nevertheless, at times when real-time prices turn sufficiently negative, wind or solar resources would curtail their output and/or in some cases, hydroelectric resources would spill water over hydro dams to reduce their energy output, thereby wasting clean energy resources that are available at negligible incremental costs, and missing an opportunity to reduce system emissions. Such curtailment of renewable energy would increase the cost of achieving state renewable energy policy objectives. Reducing inflexible baseload generation and increasing system flexibility will help mitigate surplus generation conditions and, consequently, help reduce system-wide costs.

System operators and market participants across the country have begun to contemplate various initiatives to better meet flexibility needs with existing resources or enabling new resources to do the same. For example:

- Most RTO or ISO-operated centralized wholesale power markets co-optimize energy and ancillary services markets and have implemented real-time markets that can quickly respond to changing system conditions through 5-minute dispatch and pricing intervals.

⁴⁹ See California ISO, 2016 Annual Report on Market Issues & Performance, May 2017, available at <https://caiso.com/Documents/2016AnnualReportonMarketIssuesandPerformance.pdf>

- MISO introduced a ramping product, which compensates resources (including renewable resources) for their ramping capability.⁵⁰
- CAISO implemented a flexible ramping product that compensates resources for providing ramping capacity and incentivizes loads, resources, and transmission interties with neighboring systems to reduce the ramps during peak periods.^{51,52}
- ERCOT's Operating Reserve Demand Curve offers a relatively recent refinement to the energy and ancillary services market pricing mechanism. The mechanism increases prices of energy and ancillary services as the system approaches shortage conditions. Doing so provides strong incentives for resources to generate when they are needed the most, and respond to such price signals quickly enough to capture the associated revenues.⁵³
- ERCOT's Future of Ancillary Service (FAS) proposal analyzed the redesign of ancillary services to better meet fast-ramping needs of the ERCOT system and enable new technologies to participate in meeting those needs. The analysis found that ERCOT-wide benefits would be about \$19.4 million per year due to lower start-up costs, lower-cost procurement in the energy market, and opportunity cost savings in the real-time market.^{54,55}
- The Long Island Power Authority (LIPA) has proposed that the NYISO implement a ramping product to improve system reliability and balance the grid cost effectively. The

⁵⁰ Nivad Navid, Gary Rosenwald, Scott Harvey, Ryan Sutton, and Congcong Wang, "Ramp Capability Product Cost Benefit Analysis," June 2013, available at <https://www.misoenergy.org/Library/Repository/Communication%20Material/Strategic%20Initiatives/Ramp%20Capability%20Product%20Cost%20Benefit%20Analysis.pdf> (Value taken directly from study without adjustment.)

⁵¹ See Keith Casey (California ISO), Memorandum to ISO Board of Governors re Decision on flexible ramping product proposal, January 27, 2016, available at https://www.caiso.com/Documents/Decision_FlexibleRampingProductProposal-Memo-Feb2016.pdf

⁵² An intertie is a transmission facility or group of transmission facilities that links one or more electric systems. There are interties between the ISO-NE and NYISO systems, for example.

⁵³ Johannes Pfeifenberger, Kathleen Spees, Judy Chang, Mariko Geronimo Aydin, *et al.*, *The Future of Ontario's Electricity Market: A Benefits Case4 Assessment of the Market Renewal Project*, prepared for IESO, April 20, 2017, available at <http://brattle.com/system/news/pdfs/000/001/217/original/Benefits-Case-Assessment-Market-Renewal-Project-Clean-20170420.pdf?1493215752>

⁵⁴ *Ibid.*

⁵⁵ See Samuel A. Newell, Rebecca Carroll, Pablo Ruiz, and Will Gorman, *Cost-Benefit Analysis of ERCOT's Future Ancillary Services (FAS) Proposal*, prepared for ERCOT, December 21, 2015, available at http://www.ercot.com/content/wcm/key_documents_lists/30517/667NPRR_12a_Cost_Benefit_Analysis_122115.pdf

proposal includes discussion of revenue neutral approaches, splitting current payments in favor of resources that are ramping, location-based ramp requirements, payments for demonstrated ramp capability, and fast-start payments to resources that can start and ramp in 10 minutes.⁵⁶

C. ENABLING A WIDE RANGE OF RESOURCES TO PROVIDE FLEXIBILITY

Operational flexibility can come from a wide array of resources, particularly through advances in how resources can operate and are incentivized to operate more flexibly. Operational flexibility can be provided by new technologies such as storage, demand response, advanced combined cycle and combustion turbine units; through enhancements to existing resources; and through improved regional and interregional operations of the power grid. System planners and operators continue to innovate to obtain and provide the flexibility needed to support the grid. Below are a few general areas that system operators are working on:

- **Utilizing demand-side resources.** Demand-side resources are increasingly recognized and incorporated into planning and wholesale market designs. In particular, demand reductions and small-scale generating resources located on customers' premises can provide significant value when a system is constrained. Demand-side resources have also been utilized for providing operating reserves and frequency regulation. Major investments made in advanced metering infrastructure across many parts of the country enable customers to react dynamically to system conditions.
- **Innovative monitoring equipment and data analysis.** A 2017 study by the ISO/RTO Council explores the benefits of innovations in monitoring equipment and data analyses. This is particularly important when customers own or use distributed generation that traditionally are not visible to wholesale market administrators. The report indicates that technologies that improve situational awareness at all levels of the bulk power system, and those that collect data on distributed resources will be more valuable going forward.⁵⁷
- **Enhanced ancillary services market designs.** Many RTOs and ISOs have begun to examine which new or redesigned ancillary services may become valuable in the future. New services include fast-acting regulation reserves or ramping products. The study of ERCOT's Future of Ancillary Services reflect the efficiency benefits created by

⁵⁶ Long Island Power Authority, The Need for and Design of a Ramping Product, BPWG May 8th, available at

http://www.nyiso.com/public/webdocs/markets_operations/committees/mc_bpwg/meeting_materials/2017-05-08/The%20Need%20for%20and%20Design%20of%20a%20Ramping%20Product.pdf

⁵⁷ ISO/RTO Council Emerging Technologies Task Force, *Emerging Technologies: How ISOs and RTOs can create a more nimble, robust bulk electricity system*, March 2017, available at http://www.iso-rto.org/Documents/NewsReleases/PUBLIC_IRC_Emerging_Technologies_Report.pdf

redesigning ancillary services to better match the system's fast-ramping needs and enabling new technology to provide these services.⁵⁸

- **Improved dispatchability and utilization of variable resources.** The Midcontinent ISO (MISO) and other system operators have implemented requirements that variable resources be controllable and dispatchable, and allow renewable resources to provide certain types of ancillary services.
- **Innovative transmission solutions.** There have been improvements and innovations in transmission operations, including enhanced transmission control and monitoring. For example, enhanced monitoring through synchrophasor technologies can improve system flexibility and reliability by providing more accurate real-time data to better monitor the condition of the power system.⁵⁹ In addition, the ability to better monitor real-time power flows on the grid can safely and dynamically raise the effective transfer capability of the transmission system by operating lines closer to their actual physical limits, thereby providing more flexibility without reducing reliability. In the longer-term, targeted transmission expansions (both intra- and inter-regionally) and innovative transmission planning processes that recognize the combined reliability, efficiency, and public policy benefits of transmission infrastructure will play an important role in building a more flexible and robust grid of the future.
- **Enhanced use of transmission inerties with neighboring systems.** RTOs and ISO have analyzed and implemented a number of enhancements to operations and scheduling protocols across inerties across regions. Inerties between markets provide a significant opportunity to effectively extend the geographic scope for procuring and balancing lower-cost resources. For example, because the output of renewable resources is less correlated at greater distances, better coordination across wider geographic areas helps diversify the uncertainty and variability of renewable resources. Additionally, efficient use of inerties can increase system flexibility by allowing variable generation to be balanced by the most efficient, most competitive flexible resources available in the larger geographic footprint. Specific inertia scheduling improvements include: (a) relatively small changes such as shortening the length of inertia scheduling blocks and finalizing schedules closer to dispatch time (*e.g.*, 15 minute scheduling), (b) better coordination of inertia schedules between markets (*e.g.*, coordinated transaction scheduling),⁶⁰ and (c)

⁵⁸ Samuel A. Newell, Rebecca Carroll, Pablo Ruiz, and Will Gorman, *Cost-Benefit Analysis of ERCOT's Future Ancillary Services (FAS) Proposal*, prepared for ERCOT, December 21, 2015, available at http://www.ercot.com/content/wcm/key_documents_lists/30517/667NPRR_12a_Cost_Benefit_Analysis_122115.pdf

⁵⁹ California Energy Commission Staff, *Benefits and Costs of PIER Research Enabling Synchrophasor Applications*, CEC-500-2016-036 May 2016, available at <http://www.energy.ca.gov/2016publications/CEC-500-2016-036/CEC-500-2016-036.pdf>

⁶⁰ For example, see David B. Patton, Pallas LeeVanSchaick, and Jie Chen, *Quarterly Report on the New York ISO Electricity Markets Second Quarter of 2016*, August, 2016, available at

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more complete optimization of intertie schedules across markets,⁶¹ including tie optimization and the 5-minute intertie scheduling associated with the western EIM.⁶²

- **Flexible nuclear.** Even existing nuclear resources that have not traditionally been thought of as "flexible" can provide limited flexibility value, if it is economical to do so and if nuclear safety can be maintained during flexible operations. For example, French and German nuclear plants are routinely ramped up and down to contribute to system flexibility.⁶³ Columbia Generating Station in Washington provides load-following services (with 12–72 hours' notice) to allow the regional system dispatchers to manage the large hydroelectric system in the Pacific Northwest.⁶⁴ However, in the U.S., the operation of most nuclear plants remains inflexible due to a combination of economic, technical, and safety concerns.⁶⁵

D. INTEGRATED SYSTEM PLANNING TO MEET FLEXIBILITY NEEDS

Traditionally, resource planning focuses primarily on meeting projected energy and peak load needs with a portfolio of existing and new resources in a cost-effective manner. Depending on the state regulatory environment, utility resource plans consider public policy directions and preferences, such as renewable resource development initiatives and energy efficiency and demand response programs. Many resource planners have implemented more innovative planning approaches, such as expanded scenario-based analyses of future system and market conditions to consider clean energy futures, high renewables deployment, and the cost effective use of emerging technologies. The scenarios examine important modern market and regulatory risks, such as the risk that new (and prior) investments in fossil-fired generation may face a

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http://www.nyiso.com/public/webdocs/markets_operations/documents/Studies_and_Reports/Reports/MMU_Quarterly_Reports/2016/NYISO%20Quarterly%20Report_2016-Q2_Final.pdf

⁶¹ For example, see Matthew White and Robert Pike, New York Independent System Operator, *Inter-Regional Interchange Scheduling (IRIS): Analysis and Options*, ISO White Paper, January 5, 2011, available at https://www.iso-ne.com/static-assets/documents/pubs/whtpprs/iris_white_paper.pdf

⁶² California ISO, Western Energy Imbalance Market (EIM), <https://www.caiso.com/informed/Pages/EIMOverview/Default.aspx>. Last accessed 2016.

⁶³ Nuclear Energy Agency, *Technical and Economic Aspects of Load Following with Nuclear Power Plants*, June 2011, available at <http://www.oecd-nea.org/ndd/reports/2011/load-following-npp.pdf>

⁶⁴ NEG, *Nuclear Base Load*, available at <http://nuclear-economics.com/nuclear-base-load/>

⁶⁵ For more discussion, see Peter Maloney, "How market forces are pushing utilities to operate nuclear plants more flexibly," *UtilityDIVE*, October 4, 2016, accessed June 2017, <http://www.utilitydive.com/news/how-market-forces-are-pushing-utilities-to-operate-nuclear-plants-more-flex/427496/>

future GHG emissions penalty through markets or public policies.⁶⁶ Through such scenario-based analyses, resource planners prepare for a wide range of future system or market needs.

An example of a scenario-based study is NREL's Low Carbon Grid Study that analyzes the impacts of a variety of scenarios that achieve a 50% reduction in emissions from the California electric power sector. In this study, NREL tests different conventional and enhanced flexibility scenarios and examines the outcomes of production costs, emissions, curtailments, and imports. Enhanced flexibility includes no minimum local generation requirements, increased usage of pumped hydro and energy storage, and less strict limits on hydro and pumped storage for providing ancillary services. After testing these different scenarios, they find that more flexible institutional frameworks and more geographically diversified regional generation portfolios can decrease curtailments by 10%, reduce costs up to \$800 million, and reduce GHG emissions by up to 14% compared to conventional, less flexible frameworks and less geographically diversified generation portfolios.⁶⁷

Utility resource planners are becoming more aware of the limitations of traditional analytical tools. Existing resource planning tools can be quite sophisticated and detailed, including nodal production cost models that simulate hourly operations and market revenues for all supply resources on the system, and capacity expansion models that optimize future resource developments to meet energy, capacity, and renewable energy requirements in a least-cost manner. These models typically simulate deterministic market conditions, but often do not fully capture the uncertain intra-hour market and operational effects of significant amounts of variable wind and solar resources. These types of resources require tools that analyze real-time market conditions, including intra-hour operations and real-time uncertainties in demand, resource availability, and variable resource output. Planners have already been identifying and implementing solutions to expand their analytical toolkit to better capture these real-time market and operational dynamics. Some approaches include coordination on special regional planning initiatives, coordination with RTOs on special reliability or renewable integration studies, and use of more granular simulation models that capture real-time conditions. For example, in 2012, NREL published the Renewable Electricity Futures Study that analyzed the extent to which renewable energy can supply U.S. electricity demand over the next several decades. The study found that renewable resources could reliably supply 80% of total U.S. electricity generation in 2050 with currently-available technologies and added flexibility, such as

⁶⁶ See, for example, the following study examining the GHG policy-related risks faced by new natural-gas-fired combined cycle plants, Judy Chang, Kathleen Spees, Metin Celebi, and Tony Lee, *Covering New Gas-Fired Combined Cycle Plants under the Clean Power Plan*, November, 2016, available at http://www.brattle.com/system/publications/pdfs/000/005/374/original/Covering_New_Gas-Fired_Combined_Cycle_Plants_under_the_Clean_Power_Plan.pdf?1479151991

⁶⁷ Gregory Brinkman, *et al.*, National Renewable Energy Laboratory, *Low Carbon Grid Study: Analysis of a 50% Emission Reduction in California*, January, 2016.

through transmission expansions, resource portfolios with more flexible supply and demand side resources, and enhanced power system operations.⁶⁸

At a high level, planners strive to compare the cost of alternative resource development plans. In a traditional setting, it was fairly straightforward to analyze and compare different resource options. But with the expansion of demand-side resources, renewable resources, and other new technologies (such as storage technologies), improving planning tools to better capture the operational characteristics of different resources options has become increasingly important and urgent. In the past, the “baseload,” “intermediate,” “peaking,” framework was a useful framework for identifying the optimal resource mix. Today, resource planners have moved away from that framework and are exploring the full operational and reliability characteristics of a variety of portfolios to identify the most optimal resource mix that can meet evolving future system needs.

E. ALIGNING CLEAN ENERGY POLICIES WITH SYSTEM NEEDS

In recent years, some states have increased their interest in procuring and using clean energy resources to help meet their environmental and GHG emissions policy goals. Such public policy directions have inspired important discussions about whether and how wholesale power markets can be used to accommodate or help facilitate states’ desired energy policy objectives. Many suggestions have been presented in different forums to explore how clean energy policies might affect wholesale electricity markets that previously had not been designed for this purpose. For example, in 2016, the New England Power Pool (NEPOOL) created its Integrating Markets and Public Policy (IMAPP) initiative to explore potential advancements to the regional wholesale power markets to better incorporate the states’ public policy needs.⁶⁹ Through this initiative, many stakeholders submitted proposals, including options for: (1) carbon pricing in electricity markets, (2) forward clean-energy markets, and (3) two-tiered pricing reforms for ISO-NE’s forward capacity market to better incorporate policy-driven investments.⁷⁰ The New York ISO, California ISO, and PJM are also exploring mechanisms for internalizing state GHG and environmental policies into existing wholesale power markets. These efforts generally recognize the need for power markets to incorporate clean-energy attributes and provide appropriate incentives for a wide range of new and existing resources to help meet the states’ public policy objectives. These efforts generally do not draw a distinction between “baseload” and other resources in considering options, as that terminology has limited relevance to the policy issues,

⁶⁸ T. Mai, D. Sandor, R. Wiser, T. Schneider, *Renewable Electricity Futures Study: Executive Summary*. NREL/TP-6A20-52409-ES. Golden, CO: National Renewable Energy Laboratory, 2012.

⁶⁹ New England Power Pool, Integrating Markets and Public Policy, <http://www.nepool.com/IMAPP.php>. Last accessed June 2017.

⁷⁰ New England Power Pool, NEPOOL 2016 IMAPP Proposals, available at http://nepool.com/uploads/IMAPP_20170125_ISO-NE_Discussion_Paper_Rev.pdf

market design issues, and operational requirements that system operators and stakeholders focus on.

IV. Future Work Needed

System operators and planners will continue to advance market designs and system operations to attract the most cost effective resources to provide a reliable supply of electric power that meets public policy objectives and customer needs. However, technologies, market fundamentals, policy priorities, and customer preferences are changing rapidly—all pointing to an increasingly broad range of different supply and demand resources; a more dynamic and versatile grid that can operationally integrate these resources and new technologies; and wholesale power markets that will increasingly reward both supply and demand resources for providing well-defined services and attributes such as energy, capacity, flexibility, and emissions reductions. How well traditional “baseload” generation will fare in this new environment will depend on the combination of cost effectiveness and operational and public policy attributes these resources bring to the market compared with other existing and new resources.

While market administrators and system planners have been developing new resource strategies and market rules to adapt to the changing system, the industry faces a number of challenges. For example, not all planning processes, operating procedures, and market designs have fully adapted to the emerging technologies, public policy, and customer needs faced by the industry. Below is a brief list of subject matters that will require more work going forward:

- **Market Design:** How to design markets to properly value and compensate any and all resources—both demand- and supply-side resources—that can provide flexibility and desired public policy attributes to the grid;
- **New flexibility and ancillary service products:** How to define flexibility needs, at what level of urgency would they need to be defined, how should ancillary services and flexibility markets be designed, how should resources be enabled to address these needs, and how should economic and reliability tradeoffs be balanced with determining the types and quantities of ancillary services products;
- **Oversupply conditions:** What are the efficient market signals that would help create the right incentives for new generating and demand-side resources to address surplus generation events cost effectively;
- **Internalize the cost of emissions:** How can the cost of GHG emissions be internalized by energy markets to better facilitate specific states’ public policy priorities and values;
- **Resource adequacy:** How should resource adequacy planning and compensation be modified to recognize that reliability risks are shifting from system conditions during peak hours to include reliability needs during system ramping events, and how should operators determine how much different resources contribute toward addressing the evolving reliability needs throughout the year.

Policymakers, resource planners, and system operators all have a critical role in ensuring that the value of existing resources is fully realized, the power grid is operated efficiently, wholesale markets are designed well, and new technologies and innovations are mobilized to meet customer, system, and public policy needs. We recommend that these entities begin or continue to pursue the activities discussed below.

Independent System Operators and their stakeholders are critical for understanding resource needs of the different regions of the country, and for designing wholesale power markets to properly incentivize resources for meeting those needs in a least-cost manner. Key activities for RTOs and ISOs include:

- Perform planning and system studies, on a range of future market and regulatory scenarios, to help the industry better define system needs.
- Once these needs are defined, incorporate them in market design, defining new flexibility or ancillary services products if necessary.
- Expand markets to allow a broader range of demand- and supply-side resources to help meet system needs, including refined market design to more efficiently incentivize a broader range of resources to provide a variety of flexibility and other grid services.
- Consider potential market externalities, like the cost of GHG emissions, and explore mechanisms to internalize these costs to reflect the public policy objectives of various jurisdictions affected by the ISO/RTO operations.
- Improve regional and interregional transmission planning so that transmission development can facilitate meeting reliability and public policy objectives in a more cost-effective manner.
- Facilitate enhanced and broader market coordination through improved use of transmission interties and geographic expansion of regional markets to increase operational efficiencies and system-wide reliability.

Load-Serving Entities and Utility Resource Planners (including a variety of utilities) are critical for understanding resource needs. Those that operate within a centralized wholesale power market play an important stakeholder role in working with RTOs and ISOs to design markets to properly incentivize resources for meeting those needs in a cost-effective manner. Those that operate outside of a regional wholesale power market are critical for ensuring resource planning processes that identify system needs and consider a broad range of resources to meet these needs. Key activities that load-serving entities and integrated resource planners should focus on include:

- Perform planning and system studies, on a range of future market and regulatory scenarios, to help the industry better define and incorporate flexibility (and other) needs in system operations.
- Identify specific resource services and attributes that would contribute toward efficient and reliable operations.

- Consider and compare across a wide range of resource types and technologies to meet long-term needs in a cost-effective manner.

Policymakers are critical for defining resource planning objectives, addressing barriers to meeting those objectives in a cost-effective manner, and identifying and addressing externalities in planning processes and markets, such as the costs of CO₂ or GHG emissions. Key activities that policymakers engage in include:

- Work with utilities and resource planners to adapt resource planning processes to consider a broad range of resources, new technologies, and improved regional and interregional coordination to meet planning and policy objectives.
- Ensure that resource planners are considering externalities, such as those that have significant environmental and public health impacts. Revise resource planning objectives as needed, without being prescriptive of which resources should meet those needs.
- Reduce regulatory or market barriers to ensure that innovative technologies and business models can contribute to meet evolving future system needs. To the extent that flexibility can be provided by existing resources, find ways to encourage using them and remove regulatory, market, or technical barriers to ensure that new technologies receive proper compensation for their services.
- As much as possible, use market-based approaches to select the resources that can best meet the identified policy needs and objectives, including clean-energy and GHG reduction targets.

List of Acronyms

CAISO	California Independent System Operator
CO ₂	Carbon Dioxide
ECAR	East Central Area Reliability
EDF	Électricité de France
EIA	U.S. Energy Information Administration
EIM	Energy Imbalance Market
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
FAS	Future Ancillary Services
FERC	Federal Regulatory Energy Commission
GHG	Greenhouse Gas
GW	Gigawatt
HVDC	High-Voltage Direct-Current
IMAPP	Integrating Markets and Public Policy
IPP	Independent Power Producer
ISO	Independent System Operator
LBNL	Lawrence Berkeley National Laboratory
LIPA	Long Island Power Authority
LNG	Liquefied Natural Gas
LOLE	Loss of Load Event
MAAC	Mid-Atlantic Area Council
MAIN	Mid-American Interconnected Network
MATS	Mercury and Air Toxics Standards
MAPP	Mid-Continent Area Power Pool
MISO	Midcontinent Independent System Operator
MW	Megawatt
MWh	Megawatt Hour
NCAR	National Center for Atmospheric Research
NE	New England
NEPOOL	New England Power Pool
NERC	North American Electric Reliability Corporation
NOAA	National Oceanic and Atmospheric Administration

NRDC	Natural Resources Defense Council
NREL	National Renewable Energy Laboratory
NWP	Northwest Power Pool Area
NY	New York
NYISO	New York Independent System Operator
PJM	PJM Interconnection
PNM	Public Service Company of New Mexico
PV	Photo Voltaic
RA	Rocky Mountain Power Area
REV	Reforming the Energy Vision
RTO	Regional Transmission Operator (Organization)
SPP	Southwest Power Pool
STV	Southeastern Electric Reliability Council (excluding Florida)
WECC	Western Electricity Coordinating Council

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