October 23, 2017

UNITED STATES OF AMERICA BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Grid Reliability and Resilience Pricing;
Proposed Rule Docket No. RM18-1-000

RE: Comments of the American Coalition for Clean Coal Electricity and National Mining Association in Support of the Department of Energy's Grid Reliability and Resilience Pricing Proposed Rule

Pursuant to the Commission's October 2, 2017 notice in the above-captioned docket, the American Coalition for Clean Coal Electricity ("ACCCE") and the National Mining Association ("NMA") respectfully submit the enclosed comments, along with evidence for inclusion in the record, in strong support of the proposal for final action issued by the Secretary of Energy on September 28, 2017, and published by the Department of Energy ("DOE") in the Federal Register on October 11, 2017 ("DOE Proposal"). The country is at a crossroads, and urgent Commission action is required before the value provided by critical baseload generation capacity is lost forever.

All generating resources bring different benefits to the electricity grid. This is why we support a diversified energy supply – one focused first on energy.[1] Each fuel source has unique value. America needs a generating portfolio that exhibits the balanced diversity that will result

[1] *Contra* Ernest Moniz, Sec'y, Dep't of Energy (2013-2017), Address to the Carnegie Endowment for International Peace (Nov. 13, 2015) ("We say 'all of the above,' but let me be very clear: 'all of the above' starts out with a commitment to low carbon."); *but see* Daniel Moore, *State PUC Member Sees Opportunity for Infrastructure, Innovation Under Trump*, PITTSBURGH POST-GAZETTE, Nov. 28, 2016, http://powersource.post-gazette.com/powersource/policy-powersource/2016/11/28/Robert-Powelson-sees-opportunity-for-Trump-administration/stories/201611250027 ("[Mr. Powelson] said he embraces an 'all of the above' energy policy shared by Mr. Trump, a phrase associated with ensuring fossil fuels and nuclear power are part of the generating mix.").

in affordable, reliable, and resilient electricity. Electricity is not a social experiment. It is the physical backbone to modern society, and its potential loss would have a substantial impact on the economy and public health and welfare.

According to the National Academy of Sciences, a large-scale blackout could result in billions of dollars in economic impact, and risk injury or death.[2] Lawrence Berkeley National Laboratory found that momentary interruptions of electricity, outages lasting less than five minutes, represented 67% of annual cost due to U.S. power outages, totaling $52.3 billion.[3] The Oak Ridge Laboratory estimates that a four-hour power outage could cost certain industrial entities as much as $395,000.[4] The modern digital economy is particularly vulnerable to short-term outages. Analysis by the Ponemon Institute of 63 data centers found the mean total cost per minute of an unplanned outage to be $8,851, with maximum costs of as much as $17,244 per minute.[5] Minimizing the risk from disruptive events such as these is an integral part of resilience as recognized in the DOE Staff Report, DOE's Staff Study on Electricity Markets and Reliability ("DOE Staff Study"), which also emphasizes the surge in electricity costs that occurred during the 2014 Polar Vortex.[6]

The grid cannot be reliable and affordable some of the time, it must be reliable and affordable all of the time. It must therefore also be resilient. Generation diversity must be intentional and informed, not the product of "a failure of current energy pricing mechanisms to

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[2] NAT'L ACAD. OF SCI., ENHANCING THE RESILIENCE OF THE NATION'S ELECTRICITY SYSTEM 12 (2017)

[3] Kristina Hamachi LaCommare & Joseph H. Eto, *Cost of Power Interruptions to Electricity Consumers in the United States (U.S.)*, 31 ENERGY: THE INT'L J. 1845, Sep. 2006.

[4] DOUGLAS HINRICHS & MICHAEL GOGGIN, 2006 UPDATE OF BUSINESS DOWNTIME COSTS 8, Tbl. 2, ORNL/TM-2006/592 (Dec. 2006).

[5] PONEMON INST., COST OF DATA CENTER OUTAGES 14, Bar Chart 7 (Jan. 2016)

[6] U.S. Dep't of Energy, Staff Report to the Secretary on Electricity Markets and Reliability 97 (U.S. Department of Energy, 2017) ("DOE Staff Study"). For further discussion on the Polar Vortex, s*ee infra* § V.

fully and transparently value all resources."[7] This is why we so strongly support the DOE Proposal – because it is focused first on dependable and consistent electricity service at affordable prices.

As highlighted by the DOE Staff Study, as well as the DOE Proposal, traditional sources of baseload generation, including coal-fired generation, have been unfairly penalized by restructured administrative markets that focus excessively on short-run costs, that do not properly account for the reliability and resiliency benefits provided by such generation, and that fail completely to account for the benefits associated with maintaining into the future a generation portfolio with diverse fuel supplies. Indeed, a recent study by the leading global economic consulting firm IHS-Markit ("IHS") concludes that on a going forward basis (excluding sunk costs), costs of continuing to operate existing coal-fired generation facilities are significantly lower than the long-term marginal cost of building new combined cycle gas generation.[8]

Baseload coal-fired generation facilities are essential to reliability and resilience, but have not been able to recover their costs of operation through the existing restructured administrative markets. These issues have been compounded by the fact that much new generation, particularly renewable generation, receives significant extra-market subsidies at both the federal and state level – an advantage that has worsened the economic plight of traditional baseload coal-fired generators. As a result, the past several years have seen an unprecedented wave of retirements of

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[7] PJM INTERCONNECTION, ENERGY PRICE FORMATION AND VALUING FLEXIBILITY 2 (June 15, 2017) ("PJM Price Formation White Paper").

[8] LAWRENCE MAKOVICH & JAMES RICHARDS, ENSURING RESILIENT AND EFFICIENT ELECTRICITY GENERATION: THE VALUE OF THE CURRENT DIVERSE US POWER SUPPLY PORTFOLIO 5, 63-40 (Sep. 2017). For further discussion on this study *see infra* § 4.c.

coal-fired and nuclear generation capacity, and many more facilities are at risk of closure in the coming years, unless the Commission takes immediate action.

If left unabated, the prevailing market conditions, especially their inability to properly price and compensate generators for essential reliability, resiliency, and long-term price stability benefits, leave the bulk power system ("BPS") in a fundamentally weakened and vulnerable state. Availability of meaningful numbers of generators with substantial on-site fuel resources are critical to continued reliable operations and the avoidance of complete disaster. Although the North American Electric Reliability Corporation ("NERC"), Regional Transmission Organizations ("RTOs"), and Independent System Operators ("ISOs") have generally expressed confidence in the current state of electric reliability, those opinions are based, in large measure, on existing conditions and short-term forecasts, largely ignoring the trend toward premature retirements of baseload coal-fired generating capacity currently available to address reliability and resiliency needs.

However, when confronted with the potential for widespread additional retirements of existing baseload coal-fired generating capacity, and a resulting electric system that relies primarily on natural gas and renewable generation, NERC and the RTOs/ISOs have been far less sanguine about the prospects for maintaining longer-term reliability and resiliency. Indeed, a number of RTOs and ISOs have tried to explore measures intended to maintain traditional baseload capacity in the market, and have even taken some halting and less-than-full steps in that direction, a tacit recognition that existing market rules and structures are not properly valuing the reliability, resiliency, and long-term price stability benefits that traditional baseload capacity provides.

As discussed in more detail herein, however, the few revisions to existing RTO/ISO tariffs and related market structures and rules have so far been much too little and far too late. RTO/ISO tariffs and market structures and rules do not adequately compensate traditional baseload generation for the essential reliability, resiliency, and long-term price stability benefits that they provide to the BPS, and the rapid retirement of essential coal-fired generating facilities continues unabated. Without action by the Commission to remedy these tariffs and market structures, the electric system will devolve to lose the value of fuel diversity and end up overwhelmingly dependent on intermittent renewable and natural gas generation. If that happens, essential reliability, resiliency, and long-term price stability benefits of coal-fired generating facilities, and other generation with fuel on-site, will be lost for good. For the sake of the nation's consumers and suppliers, the Commission cannot let that happen. ACCCE and NMA therefore respectfully submit that ISO/RTO tariffs are unjust and unreasonable. As described below, it is critical that the Commission make such a finding, and direct RTOs and ISOs to modify their tariffs to ensure that existing coal-fired generators are able to fully recover their operating costs. This will ensure that the essential reliability, resiliency, and long-term price stability benefits of existing coal-fired generating facilities can be saved.[9]

[9] Under the Commission's rules, intervention is not necessary to make ACCCE and NMA parties to a rulemaking. See 18 C.F.R. §§ 385.102(c) and 385.214 (2017) (requiring entities to file interventions to become a "party," and defining "party" to exclude participants in rulemakings). The Commission confirms this on its website, where it states: "Intervention is not necessary for persons submitting comments in a rulemaking, administrative, or policy proceeding (RM, AD, and PL Dockets). Commenters in these dockets are considered parties with the same rights as intervenors in application-related dockets. There are no service requirements for comments filed in RM, AD, or PL dockets." See FERC Resources – Intervene, https://www.ferc.gov/resources/guides/how-to/intervene.asp (last visited Oct. 19, 2017). Nonetheless, out of an abundance of caution, and in the event that the Commission determines that an intervention is required in this proceeding, ACCCE and NMA request that they be permitted to intervene in this proceeding with full rights as parties. Their interests as representatives of the coal industry, and coal-fired generation, are set forth in detail, and ACCCE and NMA respectfully submit that their interests cannot be represented adequately by any other party. Thus, if the Commission deems interventions to be necessary, ACCCE and NMA ask that they be granted party status pursuant to Rule 214 of the Commission's Rules of Practice and Procedure. *See* 18 C.F.R. Section 385.214 (2017).

COMMUNICATIONS

All communications, correspondence, and documents related to this rulemaking should be directed to the following person:

Paul Bailey
President and CEO
American Coalition for Clean Coal Electricity
1001 G Street NW, Suite 1000W
Washington, D.C. 20001
(202) 459-4800

Hal Quinn
President and CEO
National Mining Association
101 Constitution Ave. NW, Suite 500 East
Washington, D.C. 20001
(202) 463-2600

DESCRIPTION OF ACCCE AND NMA

ACCCE is a non-profit organization that is the only national trade organization whose sole mission is to advocate at the federal and state levels on behalf of coal-fueled electricity and the coal fleet. It is made up of members representing every facet of the coal industry including electricity generators, coal producers, railroads, barge operators, and equipment manufacturers.

NMA is a non-profit trade organization dedicated to representing the interest of the entire mining industry before all branches of the United States government and the general public. NMA's mission is "to create and maintain a broad base of political support for the mining industry and to help the nation realize the economic and national security benefits of America's domestic mining capability." NMA supports and defends all mining companies by promoting the production and use of coal and mineral resources, and by addressing the current and future needs of the mining industry. NMA's membership comprises more than 325 corporations and state mining associations that span the entire spectrum of the mining industry.

DESCRIPTION OF ACCCE'S AND NMA'S INTEREST IN THE RULEMAKING

Our members are substantially interested in preserving baseload electric generation that has the systemic and economic resiliency attributes that coal can provide, such as the ability to host fuel on-site. In the last seven years, 101,000 megawatts ("MW") of coal-fired generating capacity has retired or has announced plans to retire.[10] This catastrophic pace of retirements has caused cascading effects throughout the coal industry and industries that support coal, like railway and barge transportation, not to mention coal producing communities. Roughly 90% of coal produced in the U.S. is transported by rail or barge.[11] From the peak of U.S. coal transport in 2008 to the current level of coal transport in 2016, U.S. railroads have seen a 45% decrease in carloads of coal.[12] In one year alone, from 2015 to 2016, gross revenues attributable to coal transport fell 25% for Class I railroads.[13]

Workers across the coal industry have been hit hard too. Between 2011 and the second quarter of 2017, 65,484 coal miners have lost their jobs, a 45.7% reduction.[14] In that same period nearly 8,000 jobs have been lost in fossil fuel electric power generation.[15] These quality jobs are increasingly hard to find in workers' regions, let alone across the country. Nor are jobs generally available in other energy sectors, as such opportunities "vary regionally and often do

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[10] ACCCE., RETIREMENT OF COAL-FIRED ELECTRIC GENERATING UNITS (June 11, 2017). Note that ACCCE will soon publish new estimates indicating that 107,745 MW of coal-fired generating capacity has retired since 2010.

[11] MARIANNE MINTZ, CHRIS SARICKS, & ANANT VYAS, COAL-BY-RAIL: A BUSINESS-AS-USUAL REFERENCE CASE 9 (U.S. Dep't of Energy Argonne Nat'l Lab. 2015).

[12] ASS'N OF AM. R.R., RAILROADS AND COAL 6 (2017).

[13] *Id.* at 7.

[14] *See* MINE SAFETY AND HEALTH ADMIN., *Employment/Production Data Set.*

[15] *See* BUREAU OF LABOR STATISTICS, *Quarterly Census of Employment and Wages, Private, NAICS 221112 Fossil fuel electric power generation, All Counties, 2011* and *2017*.

not correlate well with concurrent job losses in sectors such as coal mining or power plant operations."[16]

Failure to adopt the DOE Proposal also will have devastating effects on American workers who depend on the coal industry for their livelihoods. Analysis of lost coal jobs in Southwestern Virginia by the King University School of Business, Institute for Regional Economic Studies found that each coal mining job supports 1.27 jobs in other sectors of the region's economy.[17] The loss of 100 coal mining jobs would lead to 127 jobs being lost in all other industries, for a total loss of 227 jobs.[18] Each job in the coal mining industry generates almost $128,000 in earnings paid to households employed in all industries of the region's economy.[19] A loss of 100 coal mining jobs would depress total earnings paid to households employed in all industries of the local economy by $12.8 million.[20] Indeed, these impacts reverberate across the economy. Low-cost energy from coal allows U.S. manufacturing to be competitive on a global basis and manufacturing jobs to have higher wage and higher job multipliers than other industries. The permanent loss of coal-fired generation capacity undermines American manufacturing's global competitiveness.

COMMENTS

I. MAINTAINING CORE RELIABILITY AND AFFORDABILITY OF ELECTRICITY ON THE CHANGING GRID REQUIRES COMPENSATING GENERATORS' RESILIENCY ATTRIBUTES.

The requirement to have resilience as an element of reliability can no longer be overlooked when assessing infrastructure within the U.S. electricity subsector, particularly at the

[16] DOE Staff Study at 23.

[17] Sam Evans, *Economic Impacts of Job Losses in the Coal Mining Industry*, 7 KIRES Paper 1 (Feb. 2013)

[18] *Id.*

[19] *Id.* at 2.

[20] *Id.* at 2.

generation level. The DOE Proposal, as well as other recent analyses, recognize that changes on the electricity grid require recognizing resilience as a critical element of reliability. In other words, the interconnected electric grid simply cannot be considered generally reliable unless it is also specifically resilient.

NERC defines the reliability of the interconnected BPS in terms of two basic and functional aspects.[21] The first is adequacy, or the ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and reasonably expected unscheduled outages of system components.[22] The second is operating reliability, or the ability of the electric system to withstand sudden disturbances to system stability or unanticipated loss of system components.[23] NERC has adopted the resilience definition that the National Infrastructure Advisory Council ("NIAC") developed in 2010: "Infrastructure resilience is the ability to reduce the magnitude and/or duration of disruptive events. The effectiveness of a resilient infrastructure or enterprise depends upon its ability to anticipate, absorb, adapt to, and/or rapidly recover from a potentially disruptive event."[24]

The long history of reliability for the U.S. electric grid has been built on a bedrock of dependable service provided by baseload generation. Consistent baseload facilities, largely coal-fired and nuclear generation, have been expected to generate in all but the most unlikely of

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[21] Letter from Gerry Cauley, President and CEO, NERC to Hon. Rick Perry, Secretary, U.S. Dep't of Energy 2, May 9, 2017 ("NERC Letter").

[22] *Id.*

[23] *Id.*

[24] *Powering America: Defining Reliability in a Transforming Electricity Industry: Hearing before the H. Comm. on Energy and Commerce Subcommittee on Energy*, 115th Cong. (Sept. 14, 2017) (written testimony of Gerry W. Cauley, President and Chief Executive Officer, North American Electric Reliability Corporation at page 1 n.1) ("Cauley Testimony"), *available at* https://energycommerce.house.gov/hearings/powering-america-defining-reliability-transforming-electricity-industry/.

circumstances, doing so in a manner that also provided necessary ancillary services to maintain reliability. Long-term reliability planning has been a matter of resource adequacy – build enough "always on" baseload facilities to meet most needs, and supplement them with "on as needed" peaking facilities to meet higher demand. Resiliency concerns were largely focused on ensuring that transmission and distribution systems could quickly adapt to and/or recover from downed power lines to continue moving the uninterrupted flow of electrons. At the generation level, resiliency has been a function of hardening facilities to withstand natural events and securing them against man-made attacks. The traditional "adapt and recover" conceptualization of resiliency of NIAC and other entities[25] worked well in this context.

However, the electricity grid has rapidly transformed in the last eight years. Baseload generation is retiring at historic rates,[26] replaced by natural gas and intermittent renewable generation that cannot be assumed to offer traditional baseload generation's full panoply of reliability, resiliency, and long-term price stability benefits.[27] "On as needed" technology, or in the case of intermittent renewables, "on as possible" technology, is now trying and failing to take the place of "always on" generation. Some claim the penetration of natural gas and intermittent renewables has made the electric grid more diverse,[28] but generation overall has, in fact,

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[25] U.S. DEP'T OF ENERGY, TRANSFORMING THE NATION'S ELECTRICITY SECTOR: THE SECOND INSTALLMENT OF THE QER (January 2017) ("Resilience is the ability of a system or its components to adapt to changing conditions and withstand and rapidly recover from disruptions."); ELECTRIC POWER RESEARCH INST., ELECTRIC POWER SYSTEM RESILIENCY: CHALLENGES AND OPPORTUNITIES (2016) ("Resiliency includes the ability to harden the power system against—and quickly recover from HIGH-IMPACT, LOW-FREQUENCY events") ("EPRI Resiliency White Paper"); EXEC. OFFICE OF THE PRESIDENT, PRESIDENTIAL POLICY DIRECTIVE-21, CRITICAL INFRASTRUCTURE SECURITY AND RESILIENCE (February 12, 2013) (""The term 'resilience' means the ability to prepare for and adapt to changing conditions and withstand and recover rapidly from disruptions.").

[26] RETIREMENT OF COAL-FIRED ELECTRIC GENERATING UNITS, *supra* note 10 ("In 2010, the U.S. coal fleet totaled 317,000 MW of electric generating capacity. Since that time, some 101,000 MW (581 electric generating units) have either retired or announced intentions to retire.").

[27] *See* Cauley Testimony ("Dramatic advances in technology, customer preferences, public policy, and market forces are altering the generation resource mix and challenging the conventional understanding of baseload power, traditionally provided by large generating units with low maintenance and forced outage rates.").

[28] ADVANCED ENERGY ECON. INST., CHANGING THE POWER GRID FOR THE BETTER 3 (May 2017).

"diversified" from consistency and price stability toward vulnerability and price volatility. Increasing natural gas and intermittent renewable capacity additions in the coming years will challenge reliability in the future. Yet, as Commissioner Powelson has noted, the country remains confident that our generation supply is adequate due in large part to our baseload generation.[29] As traditional baseload continues to disappear, the grid moves away from a balanced diversity that produces affordable, reliable, and resilient electricity and towards a short-sighted generation portfolio driven by arbitrary investment signals and subject to significant price volatility.

There is growing awareness that an "adapt and recover" approach to resilience, at least insomuch as it assumes the consistency provided by baseload generation, must be updated. Quick recovery alone will not suffice, since on the new grid, "[r]esources may not be available when needed, particularly those that have ***not*** secured on-site fuel."[30] PJM Interconnection recently offered such an expanded concept of resilience, defining it in the context of the BPS as "preparing for, operating through and recovering from a high-impact, low-frequency event. Resilience is remaining reliable even during these events."[31] Put differently by NERC, ". . . system resiliency is becoming an enhanced yardstick for reliability."[32] This evolution in how the industry views resilience must change the way we look at the traditional definition of reliability. With generation and reliability no longer a safely assumed package deal, the adequacy

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[29] Press Release, Pennsylvania Public Utility Commission, Electric Utilities and Electric Grid Managers Highlight Reliability for Summer Months, (June 9, 2011) (statement of then-Chairman Robert Powelson) *available at* http://www.puc.state.pa.us/about_puc/press_releases.aspx?ShowPR=2999.

[30] NERC Letter at 3 (emphasis in original).

[31] PJM INTERCONNECTION, PJM'S EVOLVING RESOURCE MIX AND SYSTEM RELIABILITY 37 (2017) (emphasis added) ("PJM Resource Mix White Paper").

[32] NERC, Remarks of Mark Lauby, Senior Vice President and Chief Reliability Officer, FERC Reliability Technical Conference, Panel III: The Potential for Long-term and Large-Scale Disruptions to the Bulk Power System, June 22, 2017.

component of reliability must now assess the quantity and quality of generating capacity. As NERC explained to DOE, "[t]he adequacy of the system is maintained by having the right combination and amount of resources and transmission to deal with unexpected facility outages or extreme weather events."[33]

Reliability on the new electricity grid therefore requires increased attention to resiliency, so that the grid remains reliable no matter what. As PJM observes, "[h]istory has shown that, despite having a system that meets reliability standards and requirements, rare extreme events, such as those experienced in PJM and other parts of the world, may produce negative impacts to the system that threaten the ability to continue to deliver energy services."[34] Yet shifts in the generation mix contribute to the need for enhanced resiliency.[35] Within PJM, even where adequate resources are procured, "the reliability 'cushion' we previously enjoyed with the large fleet of coal-fired generation has substantially diminished," resulting in "emergency conditions" becoming the "'new normal' operating condition for PJM into the future."[36] At the same time, other experts note that new and emerging threats are independently increasing the importance of grid resiliency, including "cybersecurity, more extreme weather events, increasing dependence on natural gas pipelines, aging infrastructure and resource category retirements. Add to those

[33] NERC Letter at 2 (emphasis added).

[34] PJM RESOURCE MIX WHITE PAPER , *supra* note 31, at 33.

[35] EPRI RESILIENCY WHITE PAPER , *supra* note 25 at11.

[36] *Keeping the lights on — Are we doing enough to ensure the reliability and security of the US electric grid?: Hearing before the S. Comm. on Energy and Natural Resources*, S. HRG. NO. 113-271 at 57 (April 10, 2014) (testimony of Michael Kormos, Executive Vice President, PJM Interconnection). This warning, made in 2014, is particularly prescient in light of DOE's recent unprecedented action under Federal Power Act § 202(c) to preserve four reliability-critical coal-fired generating units slated for closure under environmental regulations.

more reliance on the internet of things, data and interconnected systems, which create an increased risk of cyber incidents."[37]

Not only do these issues present system threats to the grid, they also create economic risk. Analysis indicates that a diverse electricity grid that includes traditional baseload generation is more cost-effective than one that is not, and can provide long-term reasonable and stable electricity costs.[38] As the country continues to increase dependence on natural gas for electricity generation, periods of sudden high demand or loss of supply (or both) can be expected to subject end users to volatile natural gas prices, as they have already. A resilient grid not only remains reliable during these events, it also continues to provide affordable electricity.

Therefore, as large blocks of baseload generation disappear, generating portfolios must increasingly incorporate resilience as a necessary generating attribute – one that accounts for an uncertain world of high consequence, low probability events. PJM calls this attribute "fuel assurance," which "considers the capability of the resource to store fuel on-site in order to limit the exposure to a single common event. It is necessary in order to provide the energy and reserves needed to maintain system reliability, independent of external delivery infrastructure or rapidly changing weather patterns."[39]

The presence of on-site fuel, as well as the strength of that fuel's supply chain, is a critical element of the resilience attributes provided by a generating source. The evolving grid requires that these attributes be specifically recognized and priced to maintain reliability. Put differently, the DOE Proposal reflects the reality – driven by various factors, including

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[37] PJM RESOURCE MIX WHITE PAPER , *supra* note 31, at 6-12 (listing reasons why a more resilient power system is needed now).

[38] *See infra* § 4.c.

[39] PJM RESOURCE MIX WHITE PAPER , *supra* note 31, at 19.

government intervention – that the cost of reliability on the modern grid must include a mechanism to pay for resilience that does not currently exist.

II. EXISTING COAL-FIRED GENERATION PROVIDES UNIQUE RESILIENCY AND COST STABILITY ATTRIBUTES CRITICAL TO CONSISTENT AND AFFORDABLE ELECTRIC SERVICE.

a. Coal-Fired Generation Resiliency and Cost Stability Attributes.

As baseload generation, coal-fired generating facilities offer the full package of essential reliability services. According to NERC, coal-fired power plants, along with nuclear power plants, "provide frequency support services as a function of their large spinning generators and governor-control settings, along with reactive support for voltage control. Power system operators use these services to plan and operate reliably under a variety of system conditions, generally without the concern of having too few of these services available."[40] While natural gas and other resources can provide some of these services, a number of factors affect whether these resources are equipped and available to provide the full breadth of necessary reliability services.[41]

In addition to these services, traditional baseload generation also offers unmatched resiliency attributes. NERC explains that "[c]oal-fired and nuclear generation have the added benefits of high availability rates, low forced outages, and secured onsite fuel." The presence of on-site fuel positions coal-fired generation to provide critical resiliency support in response to "black sky events" that severely disrupt grid infrastructure, including high altitude electromagnetic pulses, cyber-terrorism, and hurricanes.[42] PJM notes that "recent studies, including the Black Sky/Black Start Protection Initiative, suggest that 30 days of fuel inventory

[40] NERC Letter at 2.

[41] NERC Letter at 2

[42] *See Black Sky Hazards*, ELEC. INFRASTRUCTURE SECURITY COUNCIL, http://www.eiscouncil.com/BlackSky (listing types of black sky events).

would be required to adequately respond to Black Sky type events. Although practical for nuclear, oil and coal resources, such a requirement would be a more significant challenge for natural gas plants, which could become a challenge in the future."[43]

The fuel assurance provided by coal-fired generation is not just a function of fuel being on-site, but also being secure. Coal-fired generating facilities have secure perimeters. The coal piles themselves are not vulnerable to explosion. Indeed, coal's direct supply chain to those facilities exhibits multiple attributes that diminish points of vulnerability. Coal requires less processing than other fuel types, much of which is performed at the production site. Unlike with other electricity generation fuels, coal's transportation is highly fungible – coal can be moved by barge, truck, and train.[44] It can be crushed and mixed in water to be transported through pipelines. Even where disruptions occur, on-site storage allows coal-fired generating facilities to maintain operation. "Many months of onsite fuel allow these units to operate in a manner independent of supply chain disruptions."[45] The DOE Staff Study notes that coal shipments were disrupted in 2013 due to railway maintenance, yet coal-fired generating facilities remained operational, even though stockpiles were strained.[46]

Baseload generation is a fundamental and necessary component of a reliable and resilient electricity grid. According to NERC, "having a portion of a resource fleet with high reliability characteristics, such as low forced and maintenance outage rates and low exposure to fuel supply chain issues, is one of the most fundamental necessities of a reliable BPS. These characteristics

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[43] PJM RESOURCE MIX WHITE PAPER, *supra* note 31, at 35.

[44] *Contra Benefits of and Challenges to Energy Access in the 21st Century: Fuel Supply and Energy Infrastructure: Hearing before the H. Comm on Energy and Commerce, Subcomm on Energy and Power*, H. HRG. NO. 113-124 at 70 (testimony of Donald F. Santa, President and CEO, Interstate Natural Gas Assoc. of Am.) ("Compared with other modes of transportation — a ship, an airplane, a train or a truck — a pipeline cannot be relocated in response to shifts in the marketplace.").

[45] NERC Letter at 2.

[46] DOE STAFF STUDY at 97.

ensure that 'baseload' generation is more resilient to disruptions."[47] Conversely, the loss of coal-fired and nuclear generation facilities has a substantial impact on grid fuel assurance capability. Even when assuming firm supply contracts to natural gas generation, analysis by PJM found that even moderate retirements of coal-fired and nuclear generation facilities would reduce PJM's fuel assurance capability by almost 30% if the units were replaced by natural gas facilities.[48] That capability would be cut almost in half if capacity lost from high coal-fired and nuclear generation facility retirement is replaced by natural gas, and by 60% if replaced by renewables.[49] Indeed, PJM stress-tested 98 hypothetical generation portfolios, each deemed "reliable," against a polar vortex event, and found that only 34 were also resilient.[50] Notably, the vast majority of these hypothetical 34 resilient portfolios included a high share of coal-fired generation.[51]

In the real world, it makes sense that coal would account for a high share of resilient portfolios. Coal-fired generation provides long-term cost stability that is not possible with other types of generation. For example, when the Polar Vortex caused sharp increases in the cost of natural gas, utilities were able to substitute coal-fired generation for gas generation to moderate the much larger electricity price increases that would have occurred in the absence of coal-fired generating capacity.[52]

b. Renewable Generation Vulnerabilities

Intermittent renewable generation like wind and solar is difficult to dispatch because the output is variable depending on weather. Solar generation is only available during the day, and

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[47] NERC Letter at 5.

[48] PJM RESOURCE MIX WHITE PAPER, *supra* note 31, at 24.

[49] *Id*.

[50] PJM INTERCONNECTION, APPENDIX TO PJM'S EVOLVING RESOURCE MIX AND SYSTEM RELIABILITY 41 (2017) ("PJM Resource Mix White Paper Appendix").

[51] *Id.*

[52] *See infra* § V.

has a lower capacity factor in the winter than in the summer. Wind generation likewise is by nature limited as it is only available when the wind is blowing, which tends not to correspond to peak demand during hot summer months. Intermittent renewable generation presents the reliability challenges other generation resources like coal are called upon to overcome. "Large unanticipated voltage or frequency deviations during a disturbance can lead to uncontrolled, cascading instability. With no mass, moving parts, or inertia, increasing amounts of inverter-based resources (such as solar photovoltaic) present new risks to reliability, such as managing faster fault-clearing times, reduced oscillation dampening, and unexpected inverter action."[53]

Clearly, intermittent renewable generation is not suitable to provide a broad range of essential reliability services. As far back as 2011, the California ISO warned the Commission that the high rate of intermittent renewable penetration into California's electricity grid presented growing reliability concerns, "[t]he California ISO . . . wishes to emphasize that securing [reliability] services is quickly becoming an immediate issue as California approaches a 20 percent Renewable Portfolio Standard in 2013, and continues toward a 33 percent Renewable Portfolio Standard in 2020, while during the same time period dispatchable capacity using once through cooling begins to retire. This year alone, based on an installed wind capacity of 3,598 MW, we have witnessed a drop in wind output of approximately 800 MW in less than one hour and an increase of approximately 800 MW in 30 minutes."[54]

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[53] NERC Letter at 2; *see also* DOE Staff Study at 61 ("One of the greatest challenges to integrating [variable renewable energy] lies in managing its effects (variability, uncertainty, location specificity, non-synchronous generation, and low capacity factor) on grid operations and planning.").

[54] FERC Technical Conference (November 29, 2011) (testimony of Deborah LeVine, Director, California Independent Systems Operator Corporation).

Renewables are made further vulnerable by the extensive transmission infrastructure needed to connect generation, often far from population centers, to demand.[55] Last summer, wildfire smoke caused the loss 1,000 MW of intermittent renewables, tripping two 500 kV transmission lines.[56] With increasingly higher penetration of intermittent renewables on the electricity grid, transmission-related concerns can be expected to grow.

For these same reasons as described above relating to reliability, intermittent renewables also are a poor resiliency resource. Intermittent renewables fail on both of PJM's fuel assurance capability metrics. They are assumed to be "fuel limited," or not capable of running at their rated capacity on their primary fuel for more than 72 hours, and lack any on-site storage capability.[57] While intermittent renewables may happen to be available when the electricity grid is strained, history has shown it is a gamble to count on the capacity to perform in such situations. For example, on May 3, 2017, normal system operations in the California ISO quickly turned into an emergency when a natural gas power plant came offline and energy imports failed to materialize.[58] Intermittent renewables did not come to the rescue. Rather, the impacts were heightened as the daily rapid decline of solar power occurred as evening approached.[59] The California ISO had minutes to deploy emergency reserves and quickly went from normal system operations to a Stage 1 Emergency.[60] Likewise, in ERCOT on February 26, 2008, an unexpected drop in wind generation coupled with a demand increase from cold weather

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[55] NERC Letter at 4 ("Because the system was designed with large, central-station generation as the primary source of electricity, significant amounts of new transmission may be needed to support renewable resources located far from load centers.")

[56] Cauley Testimony at 5.

[57] PJM RESOURCE MIX WHITE PAPER APPENDIX, *supra* note 50, at 24.

[58] Robert Mullin, *CAISO Recounts Tense Hours Leading to May 3 Emergency*, RTO INSIDER, May 16, 2017, https://www.rtoinsider.com/caiso-stage-1-emergency-43153/.

[59] *Id.*

[60] *Id.*

required ERCOT to cut service to large industrial customers.[61] ERCOT had 10 minutes to curtail nearly 3% of the system load to avoid blackouts.[62]

While less-intermittent renewable generation fares better as a reliability provider, it cannot compare to the quality of reliability services provided by baseload coal-fired generation. Hydropower, while acting as baseload in some parts of the country, remains susceptible to weather conditions, namely drought and freezing. Development of hydropower also is locationally constrained. Even where hydropower potential exists, capacity is constrained by reservoir requirements for downstream water demands, including fish, wildlife, and other environmental mitigation requirements. Geothermal generation is more consistent than hydropower. However, large-scale geothermal potential is largely confined to specific regions in the Western U.S.

c. Natural Gas Generation Vulnerabilities

Unlike with coal-fired generation, or other power plants with fuel on-site, natural gas power generation is vulnerable to disruptions in a variety of ways. Supply to the plants must be provided in large quantities in real time. "NERC reported in 2013 that this interdependence 'has made the power sector more vulnerable to adverse events that may occur within the natural gas industry' and 'can amplify the exposure of the bulk power system to disruptions in fuel supply, fuel transportation, and delivery."[63] Supply disruptions may be caused by a variety of factors, including pipeline disruptions, issues with gas processing, gas storage problems, or contractual arrangements that do not assure delivery when needed. These characteristics both adversely

[61] Press Release, ERCOT, Grid Event (Feb. 27, 2008) *available at* http://www.ercot.com/news/releases/show/253.

[62] *Id.*

[63] EPRI RESILIENCY WHITE PAPER , *supra* note 25 at 12.

affect resiliency benefits of natural gas as well as expose the electric grid to price shocks and volatility that can greatly increase consumer electrical costs.

i. *Pipelines*

Natural gas pipelines are vulnerable to a range of potential disruptions, including weather and cyber events. Disruption of a single major pipeline could affect not just one, but perhaps a dozen or more power plants all receiving fuel from the line.

ICF International has raised concerns about natural gas pipeline security in its analysis of electricity grid resilience.

> There were five accidental fires or explosions between 1995 and 1997 on the TransCanada pipeline, which transports gas to the New England region. While not physical security events, these events indicate the vulnerability of gas transmission lines were a physical security event perpetrated in an attempt to achieve similar results. The most significant event was an explosion in Manitoba that took out six parallel pipelines making up the TransCanada system plus two electric generators at a nearby compressor station. Two lines were returned to service the same day as the incident, three lines were not restored for more than a week, and it was roughly a month before the remaining pipeline and one generator were back in service. All interruptible service on the system was impacted and TransCanada had to stop roughly one-third of its firm supply commitments.[64]

A recent law journal article by Joseph Dancy, Director of the University of Oklahoma College of Law Oil and Gas, Natural Resources, and Energy Center, and Virginia Dancy focuses on cybersecurity of pipelines as a key concern, among others.

> While there have been no major incidents involving a domestic cyberattack on the pipeline infrastructure, the risks are increasing exponentially. . . . A November 2015 survey issued by security vendor Tripwire indicated that 82% of oil and gas industry respondents reported their organizations experienced an increase in cyberattacks over the previous 12 months. Additionally, 53% of respondents stated that the rate of cyberattacks had increased between 50% and 100% during that same

[64] ICF INT'L, ELECTRIC GRID SECURITY AND RESILIENCE ESTABLISHING A BASELINE FOR ADVERSARIAL THREATS 17 (2016).

> period. The survey noted further that almost seven out of ten respondents indicated a lack of confidence in their organizations to detect and stop attacks.[65]

Dancy also notes that "[p]hysical attacks on pipelines and pipeline systems using explosives or other means have exposed the potential vulnerability and damage that could occur should they rupture or otherwise fail."[66] The Congressional Research Service testified to Congress on the physical terrorism risks facing pipelines, recounting that "while there have been no publicly reported successful attacks on the U.S. pipeline system since 2001, existing physical security measures did not prevent two attackers from planting . . . explosive devices along two different U.S. pipelines in 2011 and 2012 discussed earlier. Their failure to detonate was fortunate."[67] Just this summer we have seen high-profile incidents of domestic pipeline sabotage.[68]

Pipelines are not subject to Critical Infrastructure Protection standards, as are elements of the BPS. While not a substitute for having fuel on-site, these standards at least assure a high level of alertness, backed by enforcement.

Dancy also cites age and condition of pipelines as a major concern.

> Despite being more important to national commerce than ever, numerous existing pipeline systems are quite dated. . . . Statistical analysis indicates pipelines more than forty years old are much more likely to rupture or leak under standard operating conditions.[69]

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[65] Joseph R. Dancy & Victoria A. Dancy, *Terrorism and Oil & Gas Pipeline Infrastructure: Vulnerability and Potential Liability for Cybersecurity Attacks*, 2 OIL & GAS, NAT. RESOURCES & ENERGY J. 579, 580-81 (2017) (footnotes omitted).

[66] *Id.* at 589.

[67] *Pipelines: Security the Veins of the American Economy: Hearing before the H Comm. on Homeland Sec., Subcomm. on Trans. Sec.*, H. Hrg. No. 114-64 at 33 (Apr. 19, 2016) (testimony of Paul W. Parfomak).

[68] William Petroski, *Dakota Access protesters claim responsibility for pipeline sabotage*, DES MOINES REGISTER, July 24, 2017, *available at* http://www.desmoinesregister.com/story/news/2017/07/24/dakota-access-protesters-claim-responsibility-pipeline-sabotage/504136001/. While this reported incident relates to an oil pipeline rather than natural gas, the vulnerabilities are not distinguishable.

[69] Dancy, *surpa* note 65, at 580.

The Electric Power Research Institute has noted concerns about overreliance on natural gas due among other things to weather-related pipeline vulnerabilities:

> While there are a number of positive impacts from increased natural gas use by the electricity industry, the emergence of this interdependency issue has made the power sector more vulnerable to adverse events that may occur within the natural gas industry (e.g., curtailment of gas supplies due to line breaks and well freeze-offs). Similarly, the system reliability of the gas industry can be impacted by events that occur in the electricity industry (e.g., loss of electric compression in the field, at processing plants, or for transportation systems)."[70]

A final issue with pipelines is environmental considerations. The country cannot afford both to lose electric generation facilities with fuel on-site and also be precluded from reliance on natural gas because pipelines cannot be built. Yet that is the situation occurring particularly in the Northeast and Mid-Atlantic, as advocates in New York, New England, and Virginia stymie new gas pipeline construction and push for facilities with fuel on-site to shut down.

ii. *Gas Processing*

Even if the pipes are working, there must be gas to put into the pipeline. Gas processing is subject to vulnerabilities that are not present in coal production. Natural gas must be provided within a set of tolerances established by regulators, pipeline operators, and customers.

> Modern lean-burning, low-emission gas turbines used to generate electricity require fine-tuned control of the combustion process to achieve optimal operation. Gasses differ in their BTU content, flame speed, Wobbe Index, dilution gasses and composition. Variation in the natural gas composition affects the calorific value of the gas which may lead to loss of combustion efficiency and eventually turbine damage, not to mention increased pollutant emissions (e.g. NOx). Due to this, turbine manufacturers specify parameters in their warranties on the content of the gas supply. The same is true for providers of long-term service agreements. Use of non-conforming gas could abrogate the terms of their warranties and service obligations.[71]

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[70] ELECTRIC POWER RESEARCH INST., 2013 SPECIAL RELIABILITY ASSESSMENT: ACCOMMODATING AN INCREASED DEPENDENCE ON NATURAL GAS FOR ELECTRIC POWER (2013).

[71] Letter from Michael E. Moore, Vice President, FearnOil Inc., to the Hon. Rick Perry, Secretary, U.S. Dep't of Energy (June 13, 2017) (on file).

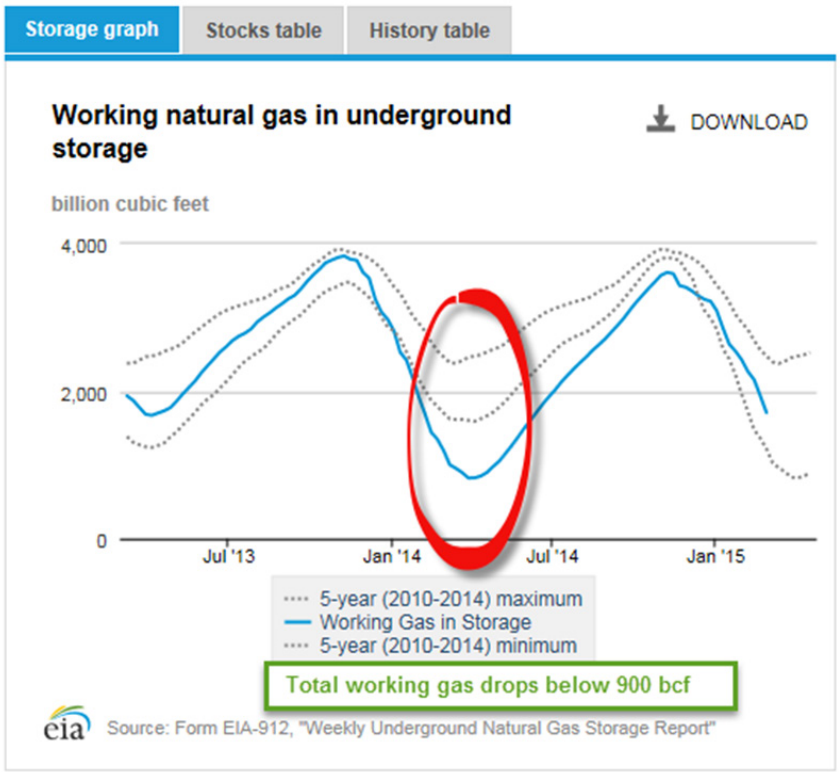
Disruption of gas processing – for example, as a result of a hurricane or other weather-related event – can have consequences for gas users far beyond the immediately affected area.

> The impact of natural gas processing vulnerabilities on electric generation was vividly displayed during the 2005 hurricane season. While not hit by either hurricanes Katrina and Rita, because of the resulting natural gas processing shortage, Florida's gas supply and composition was non-conforming to support electricity generation. The processing shortages experienced by Florida in 2005 could happen elsewhere in the eastern half of the U.S. power grid. Indeed, this could result not just from a natural event like weather, but also from a human-induced event, including a cyber incident. . . .
>
> Ironically, Florida was particularly vulnerable to these shortages even though the hurricanes did not strike there. The weather in Florida was hotter and more humid than would normally occur after a hurricane. Florida customers sought power to cool their homes, peaking electricity demand while natural gas supplies were limited. Fortunately, Florida's fuel mix, specifically the ability of the state's major utilities (FP&L and Florida Power Corporation) to burn #6 grade fuel oil, #2 grade fuel oil coal and nuclear, saved the state. However, since 2005 the #6 fuel oil plants have been repowered to natural gas, Florida Power has retired its coal and nuclear units, and new generation relies on natural gas with no ability to burn #2 fuel oil as backup.
>
> The more we rely on natural gas for electric generation, the more likely it becomes that any disruption in dry gas supply due to processing issues puts the whole eastern half of the U.S. power grid at risk.[72]

iii. *Storage*

Natural gas storage presents yet another vulnerability, which can be illustrated by two incidents: the Polar Vortex in 2014, and the Aliso Canyon gas storage leak, discovered in October 2015.

[72] *Id.*



During the Polar Vortex, demand for heating and demand for power spiked at the same time. Electricity demand in PJM and other areas reached a new winter peak, with demand in PJM at 103.5% of the previous winter peak.[73] Because the unexpectedly high demand for gas persisted for some two weeks, both for power plants and heating customers, gas storage was severely depleted. As the figure above from the Energy Information Administration ("EIA") shows, gas storage reached an historic low, and took roughly a year to rebound from the trough. Had another Polar Vortex occurred in 2015, gas supplies still would have been in the process of rebounding from the prior winter's depletion. The system may not have withstood a similar weather event the following year. ICF International said "[t]he growing dependence of

[73] NERC, POLAR VORTEX REVIEW viii (2014).

electricity generation on a source without local storage capability makes the electric grid vulnerable to threats to that generation source. . . ."[74]

The Aliso Canyon incident presents a different set of issues. The Aliso Canyon gas storage facility was leaking for at least several months before the leak was discovered and ultimately addressed. The Interagency Task Force on Natural Gas Storage Safety, which was formed to study this leak and the potential for others, found that numerous other gas storage facilities were at risk of similar problems.[75] The task force issued 44 recommendations, only two of which have been implemented by the industry thus far.[76] Implementation of these additional recommendations through regulation could constrict storage capacity below current levels, even as gas demand continues to increase.

iv. *Contractual Arrangements*

As has been broadly discussed for several years, especially since the Polar Vortex, operators of natural gas-fired power plants typically do not have firm contracts for delivery of gas. When supply is limited – for any of the foregoing reasons, including high demand by heating and other customers – those without firm delivery contracts may not be able to operate. Last year, interruptible gas transportation represented 60%-70% of natural gas delivered to power plants in PJM, 45%-55% in the Midcontinent Independent System Operator ("MISO"), 35%-45% in the New York Independent System Operator ("NYISO"), and 35%-45% in the ISO-

[74] ICF INT'L, *supra* note 64, at 9.

[75] INTERAGENCY TASK FORCE ON NATURAL GAS STORAGE SAFETY, ENSURING SAFE AND RELIABLE UNDERGROUND NATURAL GAS STORAGE 3 (U.S. Dep't of Energy and the Pipeline and Hazardous Materials Safety Admin., 2016) ("The Task Force analysis has identified a small number of underground gas storage facilities other than Aliso Canyon that have the potential to affect energy reliability.").

[76] *See id.* at 54-80.

New England ("ISO-NE").[77] As the Interstate Natural Gas Association of America notes, "electric power generators operating in restructured wholesale power markets . . . typically do not hold firm pipeline capacity."[78] The reason for this substantial reliance on interruptible capacity is in large part financial. Most natural gas generators are not able to recover the higher cost of firm transportation in the rates that they collect through the wholesale markets. It is simply not economic for them to procure firm transportation service in most cases, and therefore such generators are forced to rely on interruptible service. Even where pipeline capacity allowing for additional firm contracts is added, NE-ISO notes that the resulting benefit is often neutralized. "[E]ventually this extra capacity will likely be used for heating as gas utilities sign up more customers. To compound matters, most of the benefit from additional fuel available to generators on the coldest days will be canceled out as new natural-gas-fired generators fill the void of retiring non-gas-fired power plants."[79]

The reliance of natural gas generation on interruptible service has for several years been an issue about which the Commission has expressed concern. Electric generation competes with other uses, including home heating, industrial uses, and liquefied natural gas ("LNG") exports. Most of these uses have a higher priority on the interstate natural gas transportation system than electric generation. In addition, on a nationwide basis, 10%-20% of gas-fired generators receive service through local distribution companies, which are required to prioritize natural gas deliveries for residential and certain commercial-level customers (*e.g.,* hospitals and schools)

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[77] PA CONSULTING GRP., THE CONTRIBUTION OF THE COAL FLEET TO AMERICA'S ELECTRICITY GRID 19 n.30 (Aug. 2017) (citing EIA data).

[78] *Benefits of and Challenges to Energy Acces in the 21st Century: Fuel Supply and Energy Infrastructure: Hearing before the H. Comm on Energy and Commerce, Subcomm on Energy and Power*, H. Hrg. No. 113-124 at 71 (testimony of Donald F. Santa, President and CEO, Interstate Natural Gas Assoc. of Am.).

[79] ISO-New England, 2017 REGIONAL ELECTRICITY OUTLOOK 25 (2017) ("ISO-NE 2017 Outlook").

over electric generation.[80] This works most of the time, but during periods of peak demand, interruptible service can be interrupted and released capacity can be recalled.[81] This issue was particularly prominent during the Polar Vortex of 2014 and the Texas Freeze of 2011.[82]

The use of interruptible transportation and the reliance on local distribution companies that are forced to prioritize service for residential and specified commercial customers over electric generation also have been prominently highlighted by certain market rule changes in various RTOs and ISOs over the past few years. Specifically, both ISO-NE and the NYISO have encountered reliability problems due to the fact that they are so heavily reliant on natural gas-fired generation, and that such generation effectively has the lowest delivery priority on very cold winter days. For that reason, both ISO-NE and the NYISO have implemented programs over the past several winters that are intended to incentivize the availability of generation with fuel on-site during the winter months. These programs, which will remain in place during the coming winter, underscore the vulnerabilities associated with an electric system that is overly-reliant on natural gas-fired generation, and the need to maintain the availability of generation that can store substantial quantities of on-site fuel. Indeed, the problems with interruptible natural gas supply have forced several RTOs and ISOs, most notably ISO-NE and the NYISO, to adopt rules for the winter season that incentivize the proliferation of generators with fuel-on-site capabilities (in those regions, usually dual-fuel generators).

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[80] PA CONSULTING GRP., THE CONTRIBUTION OF THE COAL FLEET TO AMERICA'S ELECTRICITY GRID 12 (Aug. 2017).

[81] *Benefits of and Challenges to Energy Acces in the 21st Century: Fuel Supply and Energy Infrastructure: Hearing before the H. Comm on Energy and Commerce, Subcomm on Energy and Power*, H. Hrg. No. 113-124 at 71 (testimony of Donald F. Santa, President and CEO, Interstate Natural Gas Assoc. of Am.).

[82] *See* Dep't of Energy, BACKGROUND MEMO ON ELECTRICITY – NATURAL GAS INTERDEPENDENCE, QUADRENNIAL ENERGY REVIEW TASK FORCE SECRETARIAT AND ENERGY POLICY AND SYSTEMS ANALYSIS STAFF 1-2 (2014).

III. GOVERNMENT POLICIES AND MARKET DISTORTIONS HAVE ERODED COMPETITIVENESS OF EXISTING COAL-FIRED GENERATION IN RESTRUCTURED ADMINISTRATIVE MARKETS.

Notwithstanding its value to reliability and resiliency, coal-fired generation has come under unprecedented pressure. In the last seven years, 101,000 MW of coal-fired generating capacity has retired or has announced plans to retire.[83] These retirements have not resulted from the invisible hand of the markets, but rather the quite visible foot of policy on coal's throat. Those facilities that have survived must operate with substantial ongoing compliance costs. Furthermore, as explained by Commissioner Powelson, "market distortions" are sapping revenue from baseload generation.[84] These factors are increasingly undermining the ability of existing coal-fired generation to maintain operation on restructured administrative markets that do not fully value their reliability, resiliency, and long-term price stability benefits.

Driving much of the coal-fired generation retirement to date has been Environmental Protection Administration ("EPA") regulations, mainly the Mercury and Air Toxics Standards ("MATS"), the cost of which substantially reduces coal's competitive advantage in restructured administrative markets. The EIA reported in 2014 that 60,000 MW of coal-fired generation was projected to close by 2018, with the vast majority retiring by the MATS deadline.[85] Numerous energy experts warned that these closures would have an adverse impact on grid reliability. For example, in 2011, MISO testified to the Commission that "[c]urrently, the MISO system enjoys surplus capacity. However, MISO expects that the result of compliance with these [EPA] rules will be the elimination of the current surplus. A sudden removal of surplus capacity from the

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[83] RETIREMENT OF COAL-FIRED ELECTRIC GENERATING UNITS, *supra* note 10.

[84] Daniel Moore, *State PUC Member Sees Opportunity for Infrastructure, Innovation Under Trump*, PITTSBURGH POST-GAZETTE, Nov. 28, 2016, http://powersource.post-gazette.com/powersource/policy-powersource/2016/11/28/Robert-Powelson-sees-opportunity-for-Trump-administration/stories/201611250027.

[85] EIA, *AEO2014 Projects More Coal-Fired Power Plant Retirements by 2016 Than Have Been Scheduled,* (Feb. 14, 2014), https://www.eia.gov/todayinenergy/detail.php?id=15031.

system coupled with near-term load growth is worrisome as risk of resource adequacy will increase."[86]

Coal-fired generating facilities that survived MATS now bear its compliance costs. From 2012 through 2016, emission control expenditures nationwide totaled some $25 billion.[87] Over the same five-year period, seven PJM states invested a total of $2.3 billion in emission controls.[88] (These figures should be remembered when potential costs of the DOE proposal are critiqued).

The market position of coal-fired generation has been further harmed by out-of-market distortions caused by policy choices. Anyone with the impression that restructured administrative markets are free markets needs a better understanding of how they work, and how they are being distorted. As one former state utility commissioner noted, "[t]he pervasive market design issues and baseload power exits across the country compel a fundamental question. Specifically, we need to ask whether the organized markets will ever truly be allowed to function as a pure market. In other words, are policymakers and regulators capable of developing a market structure that does not succumb to the temptation to modify the price system? A look at federal and state energy and environmental policy, and the corresponding ripple effects of these policies through organized electricity markets, makes clear that the answer is: no."[89]

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[86] Midcontinent Indep. Sys. Operator, Inc., Clair Moeller, Vice President, Testimony to FERC Technical Conference (November 30, 2011).

[87] ACCCE, Comments Letter on Electricity State Policies and Wholesale Markets Operated by ISO New England, New York Independent System Operator, and PJM Interconnection 2, Docket No. AD17-0000 (Apr. 25, 2017).

[88] ACCCE, Comments Letter on Electricity State Policies and Wholesale Markets Operated by ISO New England, New York Independent System Operator, and PJM Interconnection 2, Docket No. AD17-0000 (Apr. 25, 2017).

[89] RAYMOND GIFFORD (FORMER COLORADO PUC CHAIRMAN), STATE ACTIONS IN ORGANIZED MARKETS: CONTINUED USE OF 'AROUND MARKET' SOLUTIONS TO 'FIX' MARKETS AND THE NATURAL GAS CONUNDRUM (February 2017).

A fair and open market would not include competitors whose cost of production is so heavily subsidized that the subsidy is greater than the market price. Yet that is what the Section 45 renewable energy production tax credit does.[90] This federal law provides a tax credit of $23/MWh for energy produced from wind and certain other renewable energy sources. Frequently this is more than the price customers pay for energy within PJM. The subsidy is so rich that it has led wind energy producers to bid into the market at a negative price, *i.e.*, offering to pay customers to take their power. Imagine going to two car dealers to buy a car. Dealer A tells you the price is $30,000. Dealer B is so heavily subsidized that he offers you the car for free and still makes money. That is the circumstance resulting from renewable tax credits, and it is a prime distortion in restructured administrative markets. PJM has reported negative energy market offers from wind generation enabled by the federal wind subsidies.[91] PJM warned that these subsidy-enabled negative offers "negatively impact all resources by distorting price signals and eroding revenue streams." The federal subsidization does not stop there. EIA determined that wind and solar generation received $11 billion in direct payments from various federal agencies in 2013 alone.[92] These distortions have had a direct impact on traditional baseload generation. "The erosion of value for assets needed to maintain critical resources used to ensure reliability is of particular concern given the intermittency of renewable resources."[93]

A second distortion comes from State electricity mandates known as "renewable portfolio standards." These mandates require that a certain and growing percentage of power come from

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[90] 26 U.S.C. § 45.

[91] PJM PRICE FORMATION WHITE PAPER , *supra* note 7, at 5.

[92] EIA, DIRECT FEDERAL FINANCIAL INTERVENTIONS AND SUBSIDIES IN ENERGY IN FISCAL YEAR 2013 xv, tbl. ES2 (2015).

[93] PJM PRICE FORMATION WHITE PAPER , *supra* note 7, at 5.

renewable sources. Back to the car market example, not only does Dealer A have to compete against subsidies, but he is not even allowed to compete for an increasing portion of the market.

These government policies have a real impact on coal-fired generation's market standing. Under current market rules, investments by the coal fleet to comply with EPA regulations like MATS are difficult, if not impossible, to recover. To make matters worse, prices are being suppressed by resources that receive subsidies or payments outside of restructured administrative markets. In addition, large federal subsidies and state renewable portfolio standards tilt the playing field against coal-fired generators. These factors combined make it difficult for coal-fired generation facilities to recover revenues in restructured administrative markets to remain operational. In regulated markets, policy makers consider compliance costs like these in light of the benefits provided by the generating facility.[94] While the obligation to serve, coupled with integrated resource planning, has enabled traditionally regulated markets to maintain sufficient planning reserves to meet current and future needs, levels of planning reserves in restructured administrative markets by and large have been left to market forces.[95] Yet under the pressure of government policies, coal-fired generation will be unable to play its optimal role in meeting these planning reserves unless the markets properly values the benefits provided by coal-fired generating capacity.

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[94] MATTHEW J. MOREY, LAURENCE D. KIRSCH, B. KELLY EAKIN, & ROBERT J. CAMFIELD, ENSURING ADEQUATE POWER SUPPLIES FOR TOMORROW'S ELECTRICITY NEEDS (Electric Markets Research Foundation, 2014).

[95] *Id*.

IV. FLAWS IN RESTRUCTURED ADMINISTRATIVE MARKETS THAT PREVENT FULL VALUATION OF COAL-FIRED GENERATION BENEFITS CREATE IMMINENT RISK OF LOSING DIVERSITY NEEDED TO ENSURE AFFORDABLE, RELIABILITY, AND RESILIENT ELECTRICITY SERVICE.

a. Restructured Administrative Markets do not Fully Value Benefits of Coal-Fired Generation.

Besides providing other essential reliability services like frequency response and voltage support – particularly in situations where natural gas generation is fuel-constrained – the fuel assurance capabilities of baseload coal-fired generation clearly provides necessary value to consumers who rely on a dependable source of electricity. However, this value is not being properly compensated by restructured administrative markets cash flows and thus is not being properly internalized into current power plant decision making. These markets focus on ensuring reliability by generating market cash flows that are intended to be sufficient to cover certain costs of a peaking unit. Even if this does achieve a reliability-desirable portfolio (and it is not certain that it does) accounting for reliability alone will not necessarily result in the fuel assurance capability necessary to support resiliency. PJM's own analysis concluded that portfolios resilient to a polar vortex scenario require more than simply having enough units installed to ensure reliability.[96]

The inability of "lowest cost" market constructs to incentivize fuel assurance at its lowest cost, or at all, was not a central concern when the restructured administrative markets were first formed. At that time the lowest cost generation sources – baseload coal-fired and nuclear generation facilities – already incorporated high fuel assurance. Thus, restructured administrative markets have long enjoyed the fuel assurance provided by these facilities as an unmonetized positive externality. However, the circumstances have radically changed.

[96] *Supra* § II.a.

Government policies that have penalized coal-fired generation and presently low natural gas prices have diminished coal's market position. In many cases now, the lowest bid generation is no longer the most dependable, but rather the most vulnerable to disruption. The markets have not kept pace. The free resiliency ride has continued, making it difficult for the coal-fired generating capacity that has long served as a hedge against disruption to remain competitive. Restructured administrative market constructs fail to balance demand and supply at market-clearing prices high enough to support the full cost of supply with the desired level of reliability and resiliency. It should be cost effective to retire and replace a power plant only when its continued cost of operation becomes greater than the cost of replacement, taking account of both reliability and resiliency. Because market-based cash flows for energy and capacity fail to capture the value of fuel assurance, they are chronically and artificially too low to cover the costs of a power supply portfolio that delivers reliable, resilient, and efficient electric service.

Restructured administrative markets clearly need intervention beyond what has been thus far applied to address grid resilience. The DOE Staff Report points out that market mechanisms are designed to incentivize individual resources rather than develop balanced portfolios.[97] As NERC notes, "[p]lanning approaches, operational coordination, and regulatory partnerships are needed to assure fuel deliverability, availability, security (physical and cyber), and resilience to potential disruptions. Unfortunately, an approach is not obvious in electricity markets today."[98] Put bluntly by Commissioner Powelson, "[m]any of these competitive markets have not developed a means by which to value reliability or fuel diversity . . ."[99] Yet, as markets have found that market prices have not always provided sufficient incentives to maintain required

[97] DOE Staff Study at 102.

[98] NERC Letter at 2.

[99] Robert Powelson, Commissioner, Pennsylvania Pub. Util. Comm'n, and President, Nat'l Ass'n of Regulatory Util. Comm'rs, Remarks to the Nuclear Regulatory Institute (May 25, 2016).

levels of reserves, they have attempted numerous market adjustments, including the establishment of separate capacity markets, to add additional resources.[100] These efforts have not been successful to date.[101]

PJM's recent efforts offer perhaps the best example. In PJM, generators are compensated for generation (the power consumed), capacity (an agreement to be available to produce power in the future), and ancillary services (voltage support and other services necessary to make sure the power grid is reliable). In recent years, energy payments have accounted for somewhat more than 70% of total revenues, with capacity accounting for about 25%, and ancillary services around 3%.[102] Following years of complaints that subsidized power plants are depressing prices both for energy and for capacity, forcing unsubsidized competitors out of business, PJM in recent years has made a number of adjustments. It has instituted a "minimum offer price rule" ("MOPR") to prevent new subsidized plants, but not existing ones, from artificially depressing capacity market prices. PJM has also established a new category of capacity with tighter rules – to prevent, for example, bundlers of demand response (agreements not to use energy) from failing to perform when needed.

Despite PJM's efforts, subsidized power plants continue to artificially depress capacity prices. To counteract this ongoing problem, a subgroup within PJM is currently considering the so-called "Capacity Market Repricing Proposal," which is a market adjustment that would potentially affect the viability of dozens of power plants. The stakeholder group considering this proposal – the Capacity Constructs/Public Policy Senior Task Force ("CCPPSTF") – has proposed to "reprice" capacity to a higher amount than the price that results from market

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[100] MOREY, *supra* note 95.

[101] *Id*.

[102] PJM INTERCONNECTION, PJM INTERCONNECTION RESPONSE TO THE 2016 STATE OF THE MARKET REPORT 4 (2017).

bidding. This approach would help unsubsidized power plants who bid less than the amount they need to remain profitable so they can keep operating, hopefully to get to a future point where prices rebound. The CCPPSTF proposes to calculate what higher price would have been paid for capacity had subsidized plants not bid. Notably, the auction results are not changed so that plants that lost in the bidding to subsidized plants now have a chance to be paid. Instead, the subsidized plants that won in the bidding end up getting a higher capacity price that would have been bid by theoretical units of the same type that were not built because they were too expensive because they not subsidized. This is unless, of course, a State decides the subsidized plants should not get the higher payment, in which case they would not. One reasonably might ask whether this sounds like a "market."

The adjustment does not take into account subsidies provided by federal law, such as the renewable power production tax credit, or the many other subsidized, mandated or state supported ("regulated") power producers that have long participated in restructured administrative markets unobstructed. After years of arguing that all is well, PJM has acknowledged by virtue of an energy market "uplift" (*i.e.,* extra payment) proposal that prices are distorted and need to be addressed in order to prevent further retirement of baseload units.

Today, when power is needed during hours where energy consumption increases sharply – for example, in morning hours around daybreak – "inflexible" power plants (ones that are relatively slow in their ability to increase or decrease output) are needed to meet demand. Many of these plants previously would have operated round the clock, rather than being cycled in and out of dispatch, but have been replaced by subsidized renewable and other resources. When these "inflexible" resources are needed to operate in PJM today, market rules are constructed so that they do not set the market price. Instead the market price is established, generally at a

significantly lower price, by "flexible" power generators that would have been operating based on lower price, but are backed out of dispatch temporarily as the slow-ramping plants come online or offline. Today PJM provides an "uplift" to inflexible plants during these periods. PJM now proposes to allow the inflexible block loaded plants to set the market price, presumably at a higher level. The flexible – often subsidized – resources that are backed out would receive their lost opportunity cost, essentially being paid more as well.

While PJM has not yet determined how much customers will have to pay under this construct and how much power plants would be paid, it almost certainly is not enough help to assure that power plants with resilience benefits through on-site fuel will remain in the market. Some have touted the CCPPSTF concept as a potential "market" substitute for the DOE Proposal. It is a step in the right direction, but nowhere near far enough. At the same time, it increases payments to already subsidized resources, and bears little resemblance to a market solution.

The foregoing should demonstrate that the restructured administrative markets have failed to value appropriately resilience or fuel diversity, that recent and attempted fixes similarly have failed, that the claim that the DOE Proposal is unsound because it will "distort markets" is willfully blind, and that the DOE Proposal is necessary.

b. Flaws in Restructured Administrative Markets Preventing Full Valuation of Coal-Fired Generation Creates Imminent Risk of Losing Critical Diversity.

Since their inception, the restructured administrative markets have not fully valued reliability, resiliency, and long-term price stability benefits provided by coal-fired generation. However, the "one-two punch" of punitive government policies and under-valuation by

electricity markets is pushing baseload coal-fired facilities to the brink of closure, creating substantial, permanent risk to the grid.

Numerous baseload plants in PJM have announced that they are financially challenged and are closing or contemplating closure. Accounting for stressed coal-fired and nuclear generation, as much as 16,000 MW of reliable baseload generating capacity could retire over the next several years, leaving PJM without fuel-secure baseload resources:

- NRG has announced it is retiring Will County Unit 4 (510 MW), citing market conditions;[103]
- NRG attempted to sell its 1,893 MW Homer City coal-fired power plant, but was unable to find a buyer; Standard & Poor's analysts cited lower power prices and increasing expenses as significant challenges to the facility;[104]
- Dayton Power & Light announced closure of the J.M. Stuart coal-fired power plant (2,308 MW) and the Killen Station Unit 2 coal plant (600 MW), citing market conditions making the plants not economically viable;[105]
- Westmoreland Partners announced the sale or closure of 209 MW Roanoke Valley coal-fired power plant;[106]
- PSEG announced plans to retire the 643 MW Mercer plant, citing economic pressure;[107]
- FirstEnergy also announced that units 1-4 at their Sammis coal-fired power plant (720 MW) will close, and that units 5-7 (1,490 MW) are in danger of being closed;[108]

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[103] Steve Daniels, *Days appear numbered for last remaining coal plant in Romeoville*, CRAINS CHICAGO BUSINESS December 9, 2015, *available at* http://www.chicagobusiness.com/article/20151209/NEWS11/151209785/days-appear-numbered-for-last-remaining-coal-plant-in-romeoville.

[104] Anya Litvak, *Homer City power plant files for bankruptcy, will reorganize*, PITTSBURGH POST-GAZETTE, January 11, 2017, *available at* http://powersource.post-gazette.com/powersource/companies/2017/01/11/Homer-City-files-for-bankruptcy-will-reorganize/stories/201701110148

[105] Tristan Navera, *It's official: Tow Ohio DP&L coal plants to close*, DAYTON BUSINESS JOURNAL, March 20, 2017, *available at* https://www.bizjournals.com/dayton/news/2017/03/20/its-official-two-ohio-dp-l-coal-plants-to-close.html.

[106] Press Release, Westmoreland Coal Company, Westmoreland Enters Agreement to Sell ROVA for $5 Million in Cash, (Aug. 3, 2017), *available at* http://westmoreland.com/2017/08/westmoreland-enters-agreement-to-sell-rova-for-5-million-in-cash/.

[107] Press Release, PSEG, PSEG To Retire Two New Jersey Coal Plants in 2017, (Oct. 5, 2016), *available at* https://www.pseg.com/info/media/newsreleases/2016/2016-10-05.jsp#.WeduNltSxaQ.

- FirstEnergy announced that the 2,510 MW Bruce Mansfield coal-fired power plant is at risk of closure due to the exposure to changing market conditions;[109]

- FirstEnergy noted that three nuclear power plants, Davis-Besse (894 MW), Perry (1,240 MW) and Beaver Valley (1,808 MW) are in danger of closing over the next two years due to economic reasons;[110]

- Exelon announced the closure of the Oyster Creek nuclear power plant (608 MW) a decade before the end of its operating license, citing negative economic factors;[111]

- Exelon announced the premature closure of the 837 MW Three Mile Island nuclear power plant, citing deteriorating economic value.[112]

ISO-NE likewise warns that "non-gas-fired generating options are dwindling" in its operating territory.[113] "Resources powered by oil, coal, and nuclear energy have been critical for keeping the lights on during recent winters, but these units have begun to close, citing profitability and other factors. About 4,200 MW— an amount equal to almost 15% of the region's current generating capacity—will have shut down between 2012 and 2020 and is being replaced primarily by new natural-gas-fired plants. The upcoming closures of just two of those resources—Brayton Point Station in May 2017 and Pilgrim Nuclear Power Station by May 2019—will remove 2,200 MW of non-gas-fired capacity. Over 5,500 MW of additional oil and

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[108] John Funk, *FirstEnergy to partially close coal-fired Sammis power plant and Bayshore on Lake Erie, competing gas-fired plants now being built*, CLEVELAND.COM, July 22, 2016, *available at* http://www.cleveland.com/business/index.ssf/2016/07/firstenergy_to_partially_close.html.

[109] Tom Henry, *FirstEnergy exec calls for 'urgent' aid*, THE BLADE, March 25, 2017 *available at*, http://www.toledoblade.com/Energy/2017/03/25/FirstEnergy-exec-calls-for-urgent-aid.html.

[110] Editors of Power Engineering, *FirstEnergy: Nuclear, Coal Plants Could Close Without Assistance*, POWER ENGINEERING, March 28, 2017, *available at* http://www.power-eng.com/articles/2017/03/firstenergy-nuclear-coal-plants-could-close-without-assistance.html.

[111] Matthew L. Wald, *Oyster Creek Reactor to Close by 2019*, NEW YORK TIMES, December 8, 2010, *available at* http://www.nytimes.com/2010/12/09/nyregion/09nuke.html.

[112] Ad Crable, *Exelon announces closure of Three Mile Island nuclear plant in 2019 without bailout*, LANCASTER ONLINE, May 30, 2017, *available at* http://lancasteronline.com/news/local/exelon-announces-closure-of-three-mile-island-nuclear-plant-in/article_55eeeeb4-4535-11e7-8721-ff7020d47c0a.html.

[113] ISO-NE 2017 OUTLOOK, *supra* note 79, at 27.

coal capacity are at risk for retirement in coming years, and uncertainty surrounds the future of 3,300 MW from the region's remaining nuclear plants."[114]

c. Loss of Critical Generation Diversity Will Make the Electricity Grid More Vulnerable to Systemic and Economic Impacts.

If these current trends are left unabated, the grid will become even ever more reliant on natural gas and renewables. Indeed, EIA currently projects that by 2040 almost three-fourths of U.S. electric generating capacity will be natural gas and renewables.[115] MISO, for example, was still getting 51% of its energy from coal-fired power plants and 23% from natural gas power plants in 2015.[116] But by 2030 those numbers are expected to reach parity, with coal-fired generation declining to 36% and natural gas generation increasing to 35%.[117]

Notwithstanding the confidence that some may have in the current generation portfolio, the country is moving towards one that lacks the balanced diversity necessary for affordable, reliable, and resilient electric service. NERC has warned of the peril of over-reliance on natural gas. "Assessment areas with a growing reliance on natural gas-fired generation are increasingly vulnerable to issues related to gas supply unavailability. Common-mode, single contingency-type disruptions to fuel supply and deliverability in areas with a high penetration of natural gas-fired generation are reducing resource adequacy and potentially introducing localized risks to reliability. Not only can impacts to BPS reliability occur during the gas-load peaking winter season, but they can also manifest during the summer season when electric demand is high and

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[114] *Id*.

[115] EIA, ANNUAL ENERGY OUTLOOK 2017 70 (Jan. 5, 2017).

[116] *Wayne* Barber, MISO energy mix 51% coal in 2015; expected to decline to 36% in 2030, Aug. 23, 2016, *available at* http://generationhub.com/2016/08/23/miso-energy-mix-51-coal-in-2015-expected-to-declin.

[117] *Id*.

natural gas facilities are out of service, which can lower the operational capacity and flow of the pipeline system."[118]

Even restructured administrative markets operators recognize this threat. "Although PJM's established planning, operations and markets functions should ensure that future portfolios would maintain adequate levels of reliability services and fuel security, external drivers – such as economics and public policies – have impacted, and could further impact, the mix of resources in the future. The resource mix could evolve in a way that results in less-than-adequate generator reliability attributes and fuel security because a vast majority of resources could be unavailable because, collectively, they rely either on a single technology or a single fuel. While redundancy in technology or fuel source helps to mitigate this risk, backup or dual fuel capability currently tends to be limited to supporting sustained operation for a matter of days and, therefore, is dependent on resupply.[119] The ISO-NE warns that it is "skating by" on the coldest days, "[w]ith over 35,000 MW of regional generating capability, demand resources, and imports, meeting New England's winter peak demand of roughly 21,000 MW, plus a reserve margin of about 2,600 MW, should be a routine 'day at the office' for ISO system operations. Despite sufficient capacity and some relatively mild winters, though, ISO system operators have actually managed very tight operating conditions over recent years. To keep the power flowing, the ISO has relied heavily on non-gas-fired generators and had to follow procedures several times when energy from available resources was insufficient (i.e., ISO Operating Procedure No. 4: Action During a Capacity Deficiency). If a 'perfect storm' of problems were to occur, ISO system operators could be forced to use stronger measures, such as asking the public to conserve

[118] NERC., SHORT-TERM SPECIAL ASSESSMENT: OPERATIONAL RISK ASSESSMENT WITH HIGH PENETRATION OF NATURAL GAS-FIRED GENERATION vi (2016).

[119] PJM RESOURCE MIX WHITE PAPER, *supra* note 31, at 35

electricity or, in extreme cases, ordering controlled power outages. This risk increases after the upcoming generator retirements."[120] MISO notes that its "level of concern about fuel assurance is currently low, overall, but is expected to increase significantly over time as natural gas reliance increases due to environmental requirements and evolving fuel economics . . . . toward the end of the decade, increased demand growth and the potential for additional coal-fired capacity retirements . . . are likely to further increase natural gas reliance and may require additional evaluation and actions related to fuel assurance."[121]

Not only does this lack of diversity raise serious system concerns, it subjects electricity customers to higher economic risks. Employing the diverse mix of fuels and technologies available today produces lower and less volatile power prices compared to a less diverse case with no meaningful contributions from coal-fired and nuclear generation.[122] To illustrate what is at stake "if nothing is done to arrest the erosion in the cost-effectiveness, resilience and reliability" of the current U.S. electric generating portfolio, IHS compared today's generation mix to a "less efficient diversity" portfolio.[123] IHS found that the non-peak-load price of existing coal-fired and nuclear generation capacity is roughly half that of new natural gas or intermittent renewable generation.[124] Simply put, coal-fired generation is an extremely cost-effective way to generate power. In fact, IHS calculates under such the "less efficient diversity" scenario the cost of electricity production would increase by $114 billion per year and the average retail price of

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[120] ISO-NE 2017 OUTLOOK, *supra* note 79, at 29.

[121] MIDCONTINENT INDEP. SYS. OPERATOR, INC., FUEL ASSURANCE REPORT 2-3 (Feb. 18, 2015).

[122] LAWRENCE J. MAKOVICH, AARON MARKS, & LESLIE MARTIN, THE VALUE OF US POWER SUPPLY DIVERSITY (IHS Energy, 2014).

[123] LAWRENCE MAKOVICH & JAMES RICHARDS, ENSURING RESILIENT AND EFFICIENT ELECTRICITY GENERATION: THE VALUE OF THE CURRENT DIVERSE US POWER SUPPLY PORTFOLIO (Sep. 2017).

[124] *Id.* at 36.

electricity would increase by 27%.[125] Furthermore, lowered resilience could increase the variability of monthly consumer electric bills by about 22%, while lowered reliability from this less resilient portfolio could increase outages, resulting in added costs of $75 billion per outage hour.[126] The increase in retail electricity prices would have rippling impacts across the economy. IHS projects that the U.S. GDP would be reduced by $158 billion per year, one million jobs would be lost, and every U.S. household would lose $845 per year in disposable income.[127]

Furthermore, natural gas price volatility substantially increases the economic risk created by the loss of traditional coal-fired generating capacity. As PJM warned Congress of coal-fired generation closures in 2014, "[m]any of your constituents, especially those on variable rate plans, will likely see more volatile wholesale prices than they have in years past. Although the exact amount of exposure to the wholesale markets that retail customers see in their monthly bills varies by state, there is no question that at the wholesale level, as we depend more on natural gas, volatility in the cost of electricity will significantly increase from what we have seen in past years when we could rely more on predictably-priced coal-fired and nuclear generation facilities to meet our baseload requirements."[128]

In an environment where natural gas supplies are stressed, such as a severe weather incident, LNG exports could also add to the price volatility of natural gas. Increases in exports expose U.S. natural gas market to more volatility due to varying LNG demand in global markets. Demand for U.S. LNG exports may be heavily variable and subject to competitive strategies of

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[125] *Id.* at 5.

[126] *Id.*

[127] *Id.*

[128] *Keeping the lights on — Are we doing enough to ensure the reliability and security of the US electric grid?: Hearing before the S. Comm. on Energy and Natural Resources*, S. HRG. NO. 113-271 at 57 (April 10, 2014) (testimony of Michael Kormos, Executive Vice President, PJM Interconnection).

foreign government competitors, international political developments, and natural events.[129] This has potential to add uncertainty to the U.S. market.

V. MUCH OF THE RESILIENT COAL-FIRED GENERATION CAPACITY THAT PREVENTED WORST-CASE CONSEQUENCES DURING THE POLAR VORTEX IS NOW GONE.

The threat posed by further closures of coal-fired capacity absent Commission action is real. The grid cannot afford to be, as ISO-NE warns, "skating by" on cold days. The country knows this because just three years ago, it came to the brink of a public health crisis during the 2014 Polar Vortex. On the back of coal-fired generation the nation emerged avoiding the worst. "[T]he system bent but did not break. Reliability was sustained, but at times was very close to the edge."[130] Put more directly, "[t]his country did not just dodge a bullet – we dodged a cannon ball."[131] Yet the electricity grid is now less resilient than it was than before the Polar Vortex, with fewer coal-fired facilities and more reliance on natural gas and intermittent renewables. As one former Commissioner asked, "If we have other winters like this or worse, do the lights stay on in light of what we know is coming in terms of pending retirements and infrastructure challenges that we have?"[132]

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[129] Leah Kinthaert, *Will the US Lead the LNG Pack? 10 Energy Thought Leaders Weigh In*, KNECT365ENERGY, Mar. 5, 2017, https://knect365.com/gas/article/9984f517-c53f-4f79-a572-bea4f7bb9af1/will-the-us-lead-the-lng-pack-9-energy-thought-leaders-weigh-in ("As for geopolitics, the biggest risk is probably Russia. If the world's largest natural gas exporter aggressively raises sales to Europe and China via pipelines, US players may have trouble establishing footholds in this highly competitive market." (Max Tingyao Lin, Markets Editor, Lloyd's List), "If Russia increases exports to Europe and becomes less concerned with price, there is a potential risk that US suppliers may struggle to compete with cheaper Russian pipeline supplies. However, over time, if there is a global LNG surplus, that will be absorbed by growth." (Jason Feer, Head of Business Intelligence, Poten & Partners)).

[130] FERC Technical Conference on Winter 2013-2014 Operation and Market Performance in RTOs and ISOs (April 1, 2014) (statement of FERC Chairman Cheryl LaFleur).

[131] *Keeping the lights on — Are we doing enough to ensure the reliability and security of the US electric grid?: Hearing before the S. Comm. on Energy and Natural Resources*, S. HRG. NO. 113-271 at 60 (April 10, 2014). (testimony of Nick Akins, CEO, American Electric Power).

[132] FERC Technical Conference on Winter 2013-2014 Operation and Market Performance in RTOs and ISOs (April 1, 2014) (statement of FERC Commissioner Tony Clark).

While the Polar Vortex was unexpected, the impact on the electricity grid should not have come as a surprise. In November 2013, NERC warned that "[t]he 2012–2013 winter period demonstrated that New England's natural gas dependency risk continues to escalate and existing fuel arrangements of many generators will lead to continued challenging and complex operating conditions when the power system and fuel supply deliveries are stressed."[133]

Two months later, the power system was stressed, and coal powered the country through the Polar Vortex. Commission staff later concluded that, "[p]reliminary data for January 2014 indicates that the sizable increase in electric demand was served from mostly coal-fired generation while natural gas-fired generation actually declined slightly between December 2013 and January 2014."[134] Indeed, compared to the previous winter, coal-fired generation met 92% of the electricity demand increase during the 2014 winter.[135] Although demand for power was greater in 2014, generation by natural gas decreased, because natural gas was diverted to fuel residential heating needs and gas prices soared to over three times that of coal.[136] Renewable generation was similarly constrained. During January 2014, wind produced only 4.7% of the nation's power while solar produced less than 0.2%, while hydroelectric output declined 13%.[137]

Yet even with the support of coal-fired generation, the electricity grid barely averted a full-scale emergency. For example, PJM was briefly just 500 MW away from running out of 5-minute-responding operating reserves.[138] At that point, after voltage reductions, PJM would

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[133] NERC, 2013-2014 WINTER RELIABILITY ASSESSMENT (2013).

[134] Staff presentation for the Winter 2013-2014 Operations and Market Performance in RTOs and ISOs Technical Conference 9, Docket No. AD14-8-000 (Apr. 1, 2014) ("Market Performance Technical Conference").

[135] NATIONAL COAL COUNCIL, RELIABLE & RESILIENT: THE VALUE OF OUR EXISTING COAL FLEET 12 (May 2014).

[136] *Id*.

[137] *Id*. (citing EIA, *Electric Power Monthly Data through February 2014* (April 22, 2014).

[138] Judah Rose, ICF International, *Waiting for the Next Polar Vortex*, PUBLIC UTILITIES FORTHNIGHTLY, June 2014.

have had to make emergency purchases.[139] Thereafter, PJM would have ordered rolling blackouts, which can have highly adverse consequences to public health and safety during record cold, or further decrease its operating reserves.[140] Some localized emergencies were not averted, raising questions about the viability of demand response-style capacity. For example, Kentucky's Murray State University had entered into an interruptible contract with its local utility, using the money saved to purchase a generator.[141] However when the utility notified the University during the Polar Vortex that it was shutting off its power to fulfill high demand elsewhere, that generator failed to operate.[142] The University suffered water damage to 40% of the University's buildings due to frozen pipes.[143] Fortunately, most students were away for break, but those on campus had to be moved to warm housing.[144]

These challenges arose not just because of record energy demand during the Polar Vortex, but also because of outages at natural gas generating facilities in particular, raising significant concerns about fuel assurance. According to NERC, "[o]ne of the largest issues that impacted gas-fired generation was the curtailment of fuel supply." Indeed, at one point about 75% of New England's gas generating capacity was not operating due to lack of supply or high prices.[145] Elsewhere, while MISO undertook efforts before and during the Polar Vortex to minimize natural gas disruptions, some gas-fired units in its footprint were nevertheless unable to

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[139] *Id*.

[140] *Id*.

[141] Rob Canning, Chad Lampe, & John Null, *Damage to At Least 40% of MSU's Main Buildings Due to Power Outage and Freezing Temps*, WKMS.ORG, Jan. 7, 2014.

[142] *Id*.

[143] *Id*.

[144] *Id*.

[145] NATIONAL COAL COUNCIL, *supra* note 135, at 12.

obtain gas at any price, while others chose not to purchase gas for economic reasons.[146] According to MISO, the Polar Vortex "spawned an unusually large amount of forced outages of natural gas-fired generating units. On January 6, for example, 4,410 MW of MISO gas-fired generation was unavailable for dispatch due to weather-related gas restrictions. This problem grew even worse the following day, when weather-related gas restrictions produced forced outages of 6,666 MW of gas-fired generation in MISO's footprint."[147] Significant weather-related mechanical and operating problems were reported at natural gas-fired capacity, resulting in total impacts to approximately 30-40% of the natural gas-fired capacity in the MISO North/Central region.[148] Within PJM, 24% of all forced outages resulted from natural gas interruptions – the most from a single cause.[149] This overshadows 15% of weather-related outage for all fuel types, a cause that includes frozen coal piles as well as other causes.[150] In combination with other issues such as equipment failure, 55% of total outages across the Eastern and ERCOT interconnections were at natural gas generating facilities, compared to 26% at coal-fired generating facilities.[151] This even though natural gas comprise 9% more of the generating capacity in those regions than coal-fired facilities.[152]

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[146] MIDCONTINENT INDEP. SYS. OPERATOR, 2013-2014 MISO COLD WEATHER OPERATIONS REPORT 13 (Nov. 2014).

[147] *Id.* 3-4.

[148] FUEL ASSURANCE REPORT, *supra* note 121, at 4.

[149] PJM Interconnection, ANALYSIS OF OPERATIONAL EVENTS AND MARKET IMPACTS DURING THE JANUARY 2014 COLD WEATHER EVENTS 25 (2014).

[150] *Id.*

[151] NERC, POLAR VORTEX REVIEW 13 (2014).

[152] *Id.*

It should be noted that most coal-fired generation outages within PJM occurred at facilities set to close due to EPA's MATS.[153] In other words, half of coal-fired generation outages in PJM appear to be related to not maintaining units scheduled to imminently retire.[154] Yet while the coal-fired generation that remains in service today (much of it forced into economic threat) performed strongly during the Polar Vortex, "[t]he concern related to gas plants is that as the grid becomes more reliant on gas, the shortcomings of the gas delivery system will increase unless ameliorated."[155]

The Polar Vortex raises a number of important issues for the electricity grid and restructured administrative markets. First, coal saved the country from serious systemic and economic impacts. Without 26,000 MW of baseload coal-fired generating capacity that closed between 2014-2016, the impact upon system reliability, wholesale power prices, and natural gas prices would have been substantially more severe.[156] PJM would have experienced 34 hours in which the reserve margin would have been less than 5%, while ISO-New England ("ISO-NE") margins would have been negative for 16 hours in January 2014.[157] PJM power prices would have been 55% higher and across the other markets prices would have increased between 27-47%.[158] The additional cost to consumers for winter natural gas supplies would have been as much as $35 billion."[159]

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[153] Letter from Craig A. Glazer, Vice President, Fed. Gov't. Policy, PJM Interconnection to Rep. Fred Upton, Chairman of the H. Comm. on Energy and Commerce 9 Fig. 6, Apr. 14, 2014.

[154] Rose, *supra* note 138.

[155] *Id.*

[156] Letter from Hal Quinn, President & CEO, National Mining Association, to Hon. Cheryl LaFleur, Acting Chairman, FERC (June 16, 2014).

[157] *Id.*

[158] *Id.*

[159] *Id.*

Second, even with the resilience firewall provided by coal-fired generating facilities (many of which are now retired and others now at-risk), high demand during the Polar Vortex still led to record high prices for both natural gas and electricity. This even though the period coincided with increased domestic natural gas production and imports from Canada.[160] According to Commission staff, record natural gas demand pushed spot natural gas prices for delivery on January 7 to spike around $70/MMBtu in the Philadelphia region, with some intraday trades in the Mid-Atlantic region reaching upward of $100/MMBtu. In New York, spot prices reached $55.49/MMBtu.[161] Spot natural gas prices at major Northeast points broke all previous records when cold weather returned on January 22, which propelled more severe and widespread system constraints.[162] Prices in parts of New York spiked to $120/MMBtu and $123/MMBtu.[163] A week later, on January 27, Northeast prices again spiked to almost $100/MMBtu, however this time the effects were more widespread and the spot natural gas prices in the Midwest reached over $50/MMBtu.[164] Highlighting the multiple points of vulnerability in the natural gas supply chain, cold weather in the upper Midwest coincided with an explosion on a TransCanada pipeline in Manitoba, which disrupted natural gas supplies to the Canadian and upper Midwest markets. Spot natural gas price at Northern Natural Gas' Ventura point, feeding the upper Midwest market, spiked to $54/MMBtu, an all-time record, while the price at Chicago reached over $40/MMBtu.[165] It should be noted that during the Polar Vortex

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[160] Sarah Ladislaw, *Polar Vortex, Propane Shortages, and Power Price Spikes: Perfect Storm or Signal for Broader Debate?,* CENTER FOR STRATEGIC & INTERNATIONAL STUDIES, Feb. 15, 2014, https://www.csis.org/analysis/polar-vortex-propane-shortages-and-power-price-spikes-perfect-storm-or-signal-broader

[161] Market Performance Technical Conference, *supra* note 134, at 5.

[162] *Id.*

[163] *Id.*

[164] *Id.*

[165] *Id.*

the, U.S. domestic gas market was shielded from the worldwide natural gas market. That may no longer be the case in the future if LNG exports significantly increase.

Customers purchasing electricity in restructured administrative market were also exposed to dramatic price spikes driven by high natural gas prices. During early January, the high loads faced by the electric markets were the main factor that led to high prices, requiring the RTOs and ISOs to dispatch more expensive generation to serve the higher loads. The electricity prices also included the impact of high natural gas prices and the impact of scarcity prices during a limited number of hours. During this period, localized marginalized prices were near or even above $2,000/MWh for a number of hours in PJM and a few hours in MISO.[166] On-peak average real-time prices ran from $300-$700/MWh in these regions.[167]

Third, the impacts of the Polar Vortex were not isolated to those few days in early January on which temperatures were the coldest. As a result of the sudden demand spike, natural gas storage levels across the United States fell below 1 trillion cubic feet ("Tcf"), and remained below that threshold for seven consecutive weeks, the longest such period in more than a decade.[168] Despite beginning the 2013-2014 winter with "a robust Lower 48 working gas inventory" and large amounts of additional natural gas storage injections throughout the spring and into June 2014, "working inventories remain[ed] at an 11-year low [in mid-2014], presenting a challenge for storage operators during the 2014 injection season (April through October) of building sufficient inventories for the upcoming winter."[169] Beyond the national storage level difficulties, many regions saw their reserves depleted – working gas inventories in Texas,

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[166] *Id* at 7.

[167] *Id*.

[168] *See* EIA, *Market Digest: Natural Gas (2013-2014), Record Winter Withdrawals Create Summer Storage Challenges*,, June 12, 2014, *available at* https://www.eia.gov/naturalgas/review/winterlookback/2013/.

[169] *See id*.

Louisiana, and Oklahoma fell to 10-year lows, with inventories in Washington, California, Oregon, Pennsylvania, Illinois, and West Virginia, among other areas, similarly reduced.[170]

As a result of high natural gas consumption and dwindling reserve inventories, prices spiked nationally from $3.50/MMBtu at the beginning of winter to a peak of $8.15/MMBtu, with the average winter price of $4.63/MMBtu being 33% higher than the previous winter.[171] These "price spikes were not confined to the Northeast; they also occurred at trading hubs serving consumers in the central and western United States."[172] Prices in the West between February and March periodically exceeded $8/MMBtu – quadruple the $2/MMBtu price observed in September 2013 – affecting the Rockies, California, and the Pacific Northwest, and prices in Chicago rose to levels not seen in almost a decade.[173]

Fourth, the Polar Vortex provides insight into the vulnerable future this country faces as the electric grid incorporates more natural gas generation. As NERC noted in its assessment of high natural gas penetration risks, "[d]isruptions as experienced during recent extreme weather events, such as the 2014 Polar Vortex, provide clues to the current relationships between gas availability and extremely low temperatures. As gas-fired generation increases, the amount of generation capacity potentially impacted also increases, particularly when conditions affect a wide geographic area and support from the neighboring areas is unavailable. These extreme weather events serve as early indicators of more frequent impacts to the BPS as more natural-gas-fired units continue to rely solely on just-in-time and non-firm fuel sources."[174]

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[170] *See id*.

[171] *See id*.

[172] *See id*.

[173] *See id*.

[174] NERC, *supra* note 118, at 12.

Finally, and perhaps most importantly, restructured administrative markets failed during the Polar Vortex, and the flaws have not been fixed. "What the Polar Vortex brought to light is that we have had a distorted view of system capacity due to market rules and regulatory assumptions from the [Commission] that have failed to properly value (or consider) reliability. In spite of several FERC decisions since the Polar Vortex to correct these problems, . . . ongoing trends belie assumptions that the grid has sufficient capacity to meet winter peak demands without emergency actions."[175]

Coal-fired generating capacity saved the grid during this period, yet much of that capacity has since retired. Within PJM alone, 7,273 MW of coal-fired generation capacity relied upon during the Polar Vortex has since closed.[176] American Electric Power reported that 89% of the generation that it retired because of MATS was called upon to meet demand during the Polar Vortex.[177] The New York Times summarized these concerns well in its headline, "Coal to the Rescue, but Maybe Not Next Winter."[178]

VI. THE COMMISSION SHOULD HOLD THAT EXISTING RTO AND ISO TARIFFS ARE UNJUST AND UNREASONABLE BECAUSE THEY FAIL TO VALUE RESILIENCE.

To "regulate a practice affecting rates pursuant to Section 206, the Commission must find that the existing practice is 'unjust, unreasonable, unduly discriminatory or preferential,' and that the remedial practice it imposes is 'just and reasonable.'"[179] In finding that an existing tariff provision is unjust and unreasonable, the Commission's determination must be supported by

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[175] Rose, *supra* note 138.

[176] Letter from Craig A. Glazer, Vice President, Fed. Gov't. Policy, PJM Interconnection to Rep. Fred Upton, Chairman of the H. Comm. on Energy and Commerce 9 Fig. 6, Apr. 14, 2014.

[177] *Keeping the lights on - Are We Doing Enough to Ensure the Reliability and Security of the U.S. Electric Grid?: Hearing Before the S. Comm. on Energy and Nat. Res*, 113th Cong. S. HRG. NO. 113-271 at 58 (Apr. 10, 2014).

[178] Matthew L. Wald, Mar. 11, 2014 at B1.

[179] *South Carolina Public Service Authority v. FERC*, 762 F.3d 41, 64-65 (2014).

substantial evidence, which is defined as "such relevant evidence as a reasonable mind might accept as adequate to support a conclusion" and which requires "more than a scintilla but less than a preponderance of evidence."[180]

In *South Carolina Public Service Authority*, the D.C. Circuit held that the Commission is entitled to rely on theoretical issues or problems in justifying a finding that existing tariff provisions are unjust and unreasonable, and in ordering that they be replaced by just and reasonable requirements. The court emphasized that "[w]here the '[p]romulgation of generic rate criteria clearly involves the determination of policy goals or objectives, and the selection of means to achieve them,' the '[c]ourts reviewing an agency's selection of means are not entitled to insist on empirical data for every proposition on which the selection depends."[181] As long as "a prediction is 'at least likely enough to be within the Commission's authority' and it is based on reasonable economic propositions, the court will uphold it."[182] The D.C. Circuit upheld the Commission's finding that then-existing open access transmission rules were unjust and unreasonable because they did not provide for adequate transmission planning processes, and thus had the potential to "thwart the identification of more efficient and cost-effective transmission solutions."[183] Although the Commission's rule was based primarily on the fear of such inefficient outcomes, and not on substantial experience with such outcomes, the Court held that there was sufficient evidence to support the Commission's findings, stating that "[b]ased on its expertise and experience, the Commission's determination that the current planning and cost

[180] *Id.*at 54 (internal citations omitted).

[181] *Id.* at 65 (internal citations omitted).

[182] *Id.*

[183] *Id.* at 66.

allocation practices were unjust or unreasonable 'warrants substantial deference from this court.'"[184]

Here, unlike in the Order No. 1000 context, the Commission has concrete evidence of the specific value to the electric grid provided by fuel-secure resources, as well as of the lack of adequate compensation to those resources under existing market structures. As outlined above, traditional baseload coal-fired generation provides critical reliability, resiliency, and long-term price stability benefits because of their ability to store substantial quantities of fuel on-site. Indeed, they have demonstrated their essential value to grid reliability and resiliency on numerous occasions, including during the Polar Vortex. Furthermore, the fact that the bulk of these resources are in financial distress, and that many such resources have closed in recent years, demonstrates clearly that existing market rules and market structures do not adequately value the benefits provided by these resources. These adverse consequences are more than just theoretical, as they were in the Order No. 1000 context, but rather very concrete.

Furthermore, because the Commission has been directed to consider future energy users, as well as current users, the Commission determination of just and reasonable prices must account for long-term considerations. Indeed, providing plentiful supplies of electricity at reasonable costs is at the heart of FERC's charge under the Federal Power Act. As stated by the D.C. Circuit, among the core purposes of the Federal Power Act are "preventing excessive rates" and "protecting against inadequate service and promoting the orderly development of plentiful supplies of electricity."[185] Failing to take steps to fix the markets to salvage the valuable role played by coal-fired generation in protecting the electrical grid from power outages and

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[184] *Id.*

[185] *Consolidated Edison Co., New York v. Fed. Energy Regulatory Comm'n,* 510 F. 3d 333, 342 (D.C. Cir. 2007) (internal citations and quotations omitted).

excessive electricity prices would fall short of the Federal Power Act charge to ensure "plentiful supplies of electric energy" at "reasonable prices."[186]

For these reasons, ACCCE and NMA submit that there is substantial evidence to support a determination that existing RTO/ISO market structures are unjust and unreasonable because they are resulting in the premature retirement of necessary baseload coal-fired and nuclear generation facilities. The Commission should hold that existing RTO/ISO tariff provisions and related market structures are unjust and unreasonable, and order all RTOs and ISOs to develop tariff requirements that will compensate adequately existing coal-fired and nuclear generation facilities.

VII. REMEDYING FLAWS OF RESTRUCTURED ADMINISTRATIVE MARKETS CAN BE ACHIEVED BY COMMISSION INTERVENTION WITHOUT UNDERMINING THE COMMISSION'S MARKET-BASED APPROACH.

Remedying flaws in existing market structures can be done in a manner consistent with the Commission's current framework. Over the past 20 years, the Commission's approach to electricity regulation has been fundamentally market-based, with a view toward achieving multiple objectives. One objective has been to apply competitive market forces to keep wholesale electricity prices just and reasonable while balancing other interests, including maintaining essential reliability services. As the DOE Staff Report puts it, "[t]here are tradeoffs between multiple desirable attributes for the electric grid. A more reliable and resilient system may be more costly than the least-cost system. Consumer life, safety and health are dependent on a reliable and resilient electric grid, making the grid a national security asset."[187]

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[186] *Nat'l Assoc. for the Advancement of Colored People v. Fed. Power Comm'n*, 96 S. Ct. 1806, 1811 (1976).

[187] DOE Staff Study at 61.

Some of the Commission's objectives, by their very nature, call for non-market solutions – "[b]ecause of the shortcomings of market-based approaches, non-market (i.e., regulatory) mechanisms must be part of the overall approach to ensuring long-term resource adequacy."[188] The Commission has intervened in market constructs to introduce such non-market solutions on a number of occasions.

2003 Northeast Blackout and Reactive Power Assurance. The August 2003 Northeast blackout was caused in part by a shortage of reactive power supply.[189] As a result, the Commission recognized the need to intervene to correct a flaw in the market that led to insufficient compensation for the production of reactive power. The Commission's Staff Report issued in the wake of the blackout concluded that "market participants should be compensated for the reactive power they provide, in order to ensure an adequate, reliable, and efficient supply of reactive power. That is because it is unlikely that an operator will offer to supply reactive power unless it expects to recover its costs and earn a profit."[190] As the Commission's Staff noted, failure to compensate generators for reactive power could result in both lower generation investment overall (because real power alone might not suffice to cover a particular potential new generator's costs) as well as a "reduc[tion in] the amount of reactive power capability installed in new generation equipment … because developers may elect not to add reactive capability beyond the minimum requirements" if such additional capability would not be

[188] MOREY, *supra* note 94.

[189] NERC., TECHNICAL ANALYSIS OF THE AUGUST 141, 2003, BLACKOUT: WHAT HAPPENED, WHY, AND WHAT DID WE LEARN? (Jul. 2004).

[190] FERC, STAFF REPORT ON PRINCIPLES FOR EFFICIENT AND RELIABLE REACTIVE POWER SUPPLY AND CONSUMPTION 10 (Feb. 2005).

compensated.[191] Accordingly, the Commission approved various reactive power procurement mechanisms, including cost-of-service recovery for providers in certain jurisdictional markets.[192]

MOPR. The Commission's action to ensure the sufficiency of reactive power is just one in a long line of similar interventions aimed at addressing the markets' structural deficiencies. Market prices, for example, "have not always provided sufficient incentives to maintain required levels of reserves."[193] As the Commission's staff has explained, capacity prices could be suppressed as a result of subsidies being provided to "relatively higher-cost new capacity to replace lower cost existing capacity."[194] If subsidies are less than the potential savings in reduced capacity prices, buyers would have incentive to distort the capacity markets to achieve a net benefit.[195] To counteract this potential outcome, each of the eastern RTOs/ISOs (PJM, NYISO, and ISO-NE) has implemented a MOPR, which establishes a floor that requires "new capacity resources [to] submit bids that are above a predefined value representing the going-forward costs of a benchmark resource," thereby avoiding artificial suppression of capacity prices.[196]

Transmission Constraints. The Commission has also intervened in the capacity markets to "account for transmission constraints that may prevent the output of certain capacity resources from being deliverable throughout [an] RTO/ISO region."[197] To overcome such constraints, the RTOs/ISOs require that "a certain amount of capacity be procured from

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[191] *Id*.

[192] *Id.* note 190.

[193] *See* MOREY, *supra* note 94.

[194] FERC, STAFF REPORT ON CENTRALIZED CAPACITY MARKET DESIGN ELEMENTS 24 (Aug. 2013).

[195] *Id.*

[196] *Id. See also NRG Power Marketing v. FERC*, No. 15-1452, slip op. at 3-6 (D.C. Cir. 2017) (summarizing PJM's MOPR approach) *supra* Part V.a.

[197] STAFF REPORT ON CENTRALIZED CAPACITY MARKET DESIGN ELEMENTS, *supra* note 194, at 15.

resources within the particular local area or zone," which could lead to different prices than would have otherwise applied.[198]

Day-Ahead Margin Assurance Payments. To reduce price volatility, the Commission permits RTO/ISO tariffs to provide for real-time make-whole payments. The MISO tariff, for example, provides for a Day-Ahead Margin Assurance Payments ("DAMAP"), which "protect[s] market participants' margins associated with real-time dispatch instructions that are below their day-ahead schedules."[199] That is, in order to encourage market participants to provide dispatch flexibility to MISO, to the extent that a market participant would otherwise have lost revenue as a result of complying with MISO real-time instructions in a given hour because they were dispatched a lower level than they would have been under the day-ahead schedule – such participant will be made whole through an additional payment.[200] MISO also provides a make-whole payment for instances in which a market participant is dispatched at a level *above* its day-ahead schedule – the Real-Time Offer Revenue Sufficiency Guarantee Payment.[201]

Winter Reliability Programs. Following increased forced outage levels observed between 2007 and 2012, the Commission approved ISO-NE's efforts to address concerns about potential insufficiencies of oil and LNG resulting from constrained gas transmission capacity in the region – and the resulting projected "reliability gap" of energy that would be needed in the event of unusually cold weather – through ISO-NE's "Winter Reliability Programs."[202] Since 2013, these programs have provided incentives for demand response, for generators to secure

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[198] *Id.*

[199] *See Midwest Indep. Transmission Sys. Operator, Inc.*, 145 FERC ¶ 61,259 at 11-14 (2013).

[200] *Id.* NYISO's tariff also includes DAMAP payments. *See New York Indep. Sys. Operator, Inc.*, 139 FERC ¶ 61,108 at 2 (2012).

[201] *Id.*

[202] *See, e.g.*, Andrew Gillespie, Winter Reliability Program Updated – Restructuring Roundtable (ISO-New England, 2015), *available at* https://www.iso-ne.com/static-assets/documents/2015/09/final_gillespie_raab_sept2015.pdf.

fuel arrangements leading up to winter, and have provided offsets for carrying costs of unused fuel.[203]

Taken together, these and many other examples of the Commission's recognition of market deficiencies and the non-market measures it has taken to shore up those deficiencies illustrate that, as between a theoretically "pure" market structure and a practical structure that looks outside the market in search of a balance between competitive electricity pricing and ensuring the provision of critical reliability and other services, the Commission has routinely favored the latter approach. Its litany of market interventions, often piled on top of previous market interventions, to correct or adjust for non-market policies or objectives, leaves the Commission no room to find – as some would have it do – that intervention in keeping with the Secretary's objectives is inconsistent with its past actions.

As discussed above, the current restructured administrative markets clearly have a resource adequacy problem – they are "failing to attract investment capital and to send price signals to retain existing generation in order to maintain a mix of energy resources necessary to ensure grid reliability."[204] Baseload coal-fired generation is a fundamental aspect of that diverse energy mix, and the shortcomings of the existing markets in failing to appropriately value the contributions of baseload coal-fired generation to grid reliability and resiliency strongly implies the need for a non-market solution. The Commission should recognize this need, and once again take action, consistent with its long history of similar actions, in pursuit of the optimum balance between ensuring competitive, low-cost electricity and supporting other key attributes such as reliability and resiliency, and to otherwise ensure that it produces just, reasonable, and not unduly discriminatory results.

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[203] *Id*.

[204] MOREY, *supra* note 94.

VIII. THE COMMISSION SHOULD DIRECT RTOS/ISOS TO ADOPT TARIFF RULES THAT ENSURE EXISTING COAL-FIRED GENERATING FACILITIES REMAIN IN THE MARKET.

The need for the Commission to act on the DOE's proposal is apparent. Yet the current market structure has already pushed many of the same generating resources that were primarily responsible for avoiding catastrophe in 2014 out of the picture. If no strong action is taken, many more of those resources will prematurely retire, resulting in irreparable loss of generator attributes critical to the grid's systemic and economic resilience. Urgent action is required.

The Commission repeatedly has established precedent for how problems such as this can be solved – by recognizing market deficiencies and adjusting market constructs to fit the objective. In this instance, the Commission should follow that blueprint and require RTOs/ISOs to amend their tariffs to ensure that the full reliability, resiliency, and long-term price stability benefits of existing baseload coal-fired and nuclear generating facilities are recognized in market pricing.

Many seem to be reading the DOE Proposal as demanding a Commission adjustment to the restructured administrative markets operated by ISOs and RTOs. We believe such an interpretation is reasonable, but not required. The Commission has a variety of options to achieve the objective of sustaining facilities with the resilience of fuel on-site. The Commission certainly has the authority to assure just and reasonable rates by directly addressing energy sales. It also can require adjustments to capacity markets or ancillary markets, or require through a new mechanism – such as a separate capacity tier for facilities with fuel on-site, or an entirely different mechanism placed outside energy, capacity, or ancillary markets.

We recommend that the Commission direct RTOs/ISOs to institute a payment – through a separate tier of existing capacity markets – for resilient capacity from facilities with at least 30

to 60 days of fuel on-site. Only facilities with fuel on-site would be eligible. As has been the case for other market adjustments, it should not apply based on type of fuel of the facility, but whether it has the desired attribute – in this case, resiliency from fuel on-site. At a minimum, this would apply the rule to coal-fired and nuclear generating facilities.

A separate capacity tier is justified based on the well-supported concern about loss of resilience documented by the discussion herein, the DOE Staff Study, and the DOE Proposal. Facilities with fuel on-site need to be a substantial layer of the capacity available to the grid. We do not presume here to calculate the precise amount of capacity with fuel on-site that is required, but the amount available during the Polar Vortex in 2014 was barely sufficient, and the market constructs have forced out significant amounts of fuel-secure baseload since then. At a minimum, the market for capacity with fuel on-site must be sufficient to sustain currently operating fuel-secure resources; more should be encouraged to enter. We agree with Secretary Perry that a construct resulting in a payment equal to the cost of operating and maintaining the facility, as outlined in the Secretary's proposal, plus a reasonable rate of return – which, we note, historically has been the very definition of a "just and reasonable" rate – is appropriate compensation.

Serving the need for resilient fuel-secure generation does not fit within the current capacity market constructs, which focus largely on whether there will be a sufficient amount of megawatts available in the future to meet projected load. Nor does it fit neatly in existing ancillary services markets, since the focus is on the specific service of resilience from fuel on-site. We note that PJM, at a minimum, already has instituted multi-tier capacity markets to provide extra revenue to facilities able to commit to a greater assurance of being available when needed. The requirement to have fuel on-site is a yet higher tier.

ACCCE and NMA further submit that it should be an objective of the rulemaking not only that sufficient fuel-secure resources be available to the market, but that they actually operate. This would assure that facilities with fuel on-site are available immediately in case of emergency, rather than available after a ramp-up period. Furthermore, most traditional fuel-secure resources are not engineered to cycle in and out of operation, but to operate on a steady, "always on" basis. Cycling, and the more frequent change in heat that comes with it, increases stress on metals and increases risk of failure. The two-tier capacity market construct we describe above may be best in keeping with FERC's notion of a market solution. However, an energy market solution would provide better assurance that fuel-secure facilities are at their best availability.

We also recommend that the Commission consider whether a minimum contribution to grid resilience threshold should apply. Small generators with fuel on-site – under 10 or 20 MW in size – may contribute negligibly on an individual basis to the resilience of the grid. Collectively the view may be different. The Commission should consider this issue, either as a matter to be addressed in the final rule or a subsequent action modifying it after further study.

The amount of on-site fuel required should be geared to the risk the DOE Proposal is intended to ameliorate. The background provided in the Secretary's letter to the Commission, as well as the DOE Proposal's preamble, focus among other things on natural events such as the Polar Vortex and recent hurricanes. A 30- to 60-day supply of fuel on-site would be sufficient to perform during such emergencies. A 90-day on-site fuel requirement could be unduly restrictive, limiting the number of facilities eligible for assistance under the program due to such considerations as space limitations for coal piles. Moreover, if not necessary to serve the

purpose of maintaining resiliency, an unduly high on-site fuel requirement could unnecessarily increase costs.

The program should be structured to provide for eligibility of generators within ISOs and RTOs with fuel on-site that currently may be excluded under the Secretary's proposal. Generation owned by electric cooperatives, for example, is largely coal-fired generation. These facilities may or may not be eligible under the DOE Proposal, which excludes facilities that are retail rate regulated. If eligible, they may receive little benefit if their rate structure currently provides for recovery of costs plus a rate of return as outlined in the proposed rule. Nevertheless, these facilities are under economic pressure because of punishing costs added in recent years, forcing owners to consider options such as natural gas. Therefore, the risk to resilience from the loss of facilities with fuel on-site extends to these facilities as well. As the Commission prefers market solutions, we recommend that the Commission include these facilities in a market solution. The Commission could provide that in any area subject to the rule with a deficiency of resilient generation with fuel on-site, that facilities eligible but for the proposed limitation should be able to participate in the separate capacity tier we have outlined above. At a minimum, retail rate regulated facilities in such areas should have the option to declare themselves eligible.

As an alternative, if they are contributing to resiliency by operating their own fuel-secure facilities, such entities should be exempt from having to pay for fuel-secure generating capacity through any formal RTO/ISO program. Regarding compensation, the Commission should ensure that facilities that qualify for the program are justly and reasonably compensated for the reliability and resiliency value they provide, enabling them to remain in the market to continue to provide those benefits. This would include permitting such existing facilities to recover the fixed

and incremental costs of maintaining those units, as well as amounts reflecting financial distress caused by existing markets. Existing coal-fired generation facilities should be permitted to recover (i) undepreciated capital costs and debt (including debt that has been written off for the asset but is still on the plant's books); (ii) reasonable operation and maintenance costs, including taxes; and (iii) a reasonable return on equity.

Retirements of baseload coal-fired and nuclear generation facilities have accelerated in recent years, and are projected to continue at a rapid pace in the absence of strong, effective, and decisive action from the Commission. For the reasons outlined above, we urge the Commission to implement a plan consistent with the principles set forth above to stem the tide of premature baseload coal-fired and nuclear generation facility retirements and to avoid the loss of the critical reliability, resiliency, and long-term price stability benefits they provide.

IX. ACTION ON DOE'S PROPOSAL IS AN IMPORTANT FIRST STEP TO PROTECTING THE RESILIENCY AND DIVERSITY PROVIDED BY COAL-FIRED GENERATION.

We appreciate the Commission's prompt consideration of the DOE Proposal, as well as the serious attention it is now paying to protecting the resiliency and diversity benefits that coal-fired generation has long provided the electricity grid. Finalization of the DOE Proposal is an important first step towards enabling coal-fired generation to provide these resources into the future. However, we note that the DOE Proposal's relief is limited in scope and region.

The focus of the DOE Proposal is on the erosion of baseload facilities with fuel on-site as a function of price formation inadequacies and distortions in restructured administrative markets. It must be recognized that for a different but related set of reasons, facilities with fuel on-site are facing pressures outside of ISOs and RTOs, as are facilities with fuel on-site within ISOs and RTOs that are not covered by the proposed rule (*e.g.*, facilities that are retail rate regulated). Coal is facing economic pressure everywhere from subsidized and mandated resources. This is

not a phenomenon limited to merchant units in RTO/ISO regions. We urge the Commission to take action to assure resilience from facilities with fuel on-site in all parts of the country, irrespective of market structure.

Declaring an end to the "war on coal" was long overdue. But as it has done when ending other wars, the government should now embark on an ambitious and wide ranging effort across agencies to rebuild coal equal to the effort to tear coal down. That work cannot stop here.

ACCCE and NMA appreciates the opportunity to offer its perspective on the DOE Proposal. We look forward to further action by the Commission on similar measures.

Respectfully Submitted,

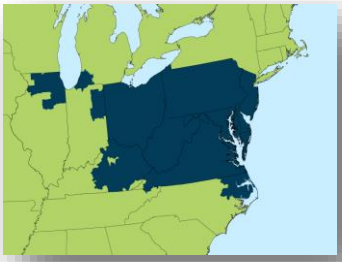
Paul Bailey
President and CEO
American Coalition for Clean Coal Electricity
1001 G Street NW, Suite 1000W
Washington, D.C. 20001

Hal Quinn
President and CEO
National Mining Association
101 Constitution Ave. NW, Suite 500 East
Washington, D.C. 20001

Attachment 1: ACCCE Blog Post, "The Coal Fleet and Grid Resilience"

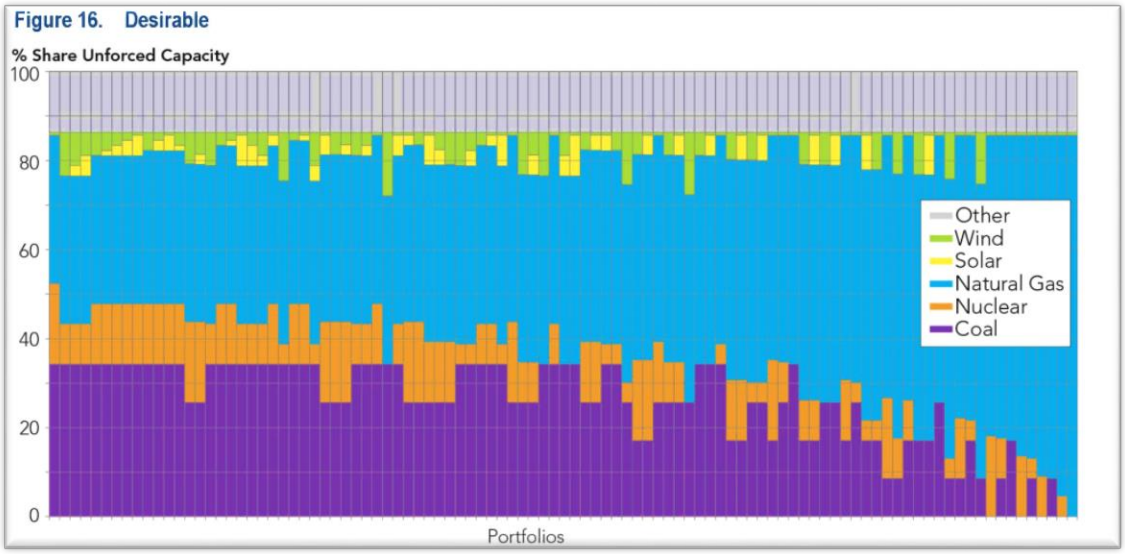
The Coal Fleet and Grid Resilience
By Paul Bailey
ACCCE President & CEO

There have been several articles and such questioning the need for baseload electricity sources, especially coal. We thought you might like to hear the other side of the argument.



Recently, PJM released a report — *PJM's Evolving Resource Mix and System Reliability*[i] — that analyzed 360 different mixes ("portfolios") of electricity resources and the effect of each of those portfolios on electric reliability in the 13-state PJM region. Each portfolio represented a different combination of coal, natural gas, nuclear, wind, solar, and other resources.[ii]

PJM determined that slightly more than one-fourth of these portfolios were "desirable" because they showed high levels of reliability.[iii] The chart below is taken from the PJM report and shows the relative percentage (vertical axis) of resources for each of the 98 desirable portfolios (horizontal axis). Coal is purple.

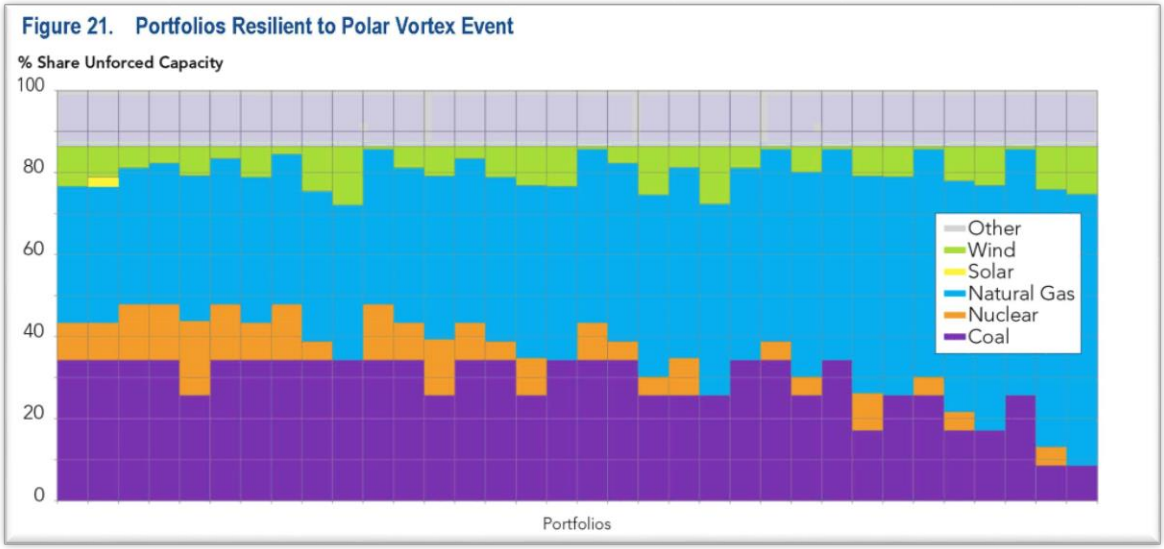


Almost half of the desirable portfolios were comprised of more than 30% coal-fired capacity.[iv] For comparison, coal comprised 34% of PJM's

capacity mix last year.[v] However, the retirement of more coal-fired capacity is expected, and low capacity prices are threatening to reduce the size of the PJM coal fleet even further.[vi]

The chart above shows that portfolios comprised of significant gas-fired generating capacity also were desirable. However, PJM expressed concerns about "operational risks" associated with natural gas that were not considered in the analysis. These operational risks could result from "infrastructure, economics, policy, and resilience."[vii]

Because of these concerns, PJM also analyzed the effects of a **polar vortex** — *only one of several possible "high impact, low frequency" (HILF) events*[viii] *that could threaten electric grid resilience.*[ix] Under assumed polar vortex conditions, only one-third of the desirable portfolios (34 out of 98) were resilient.



The maximum percentage of gas-fired generating capacity in these polar vortex portfolios decreased due to "higher unavailability rates of natural gas under a polar vortex event." On the other hand, the number of polar vortex scenarios with a high percentage of coal-fired generating capacity remained roughly the same, with coal-fired capacity exceeding 30% in slightly more than half of the resilient portfolios.[x]

We think the results of the PJM analysis demonstrate several important points. The most obvious point is that all grid operators should

evaluate HILF events, like PJM has begun doing. The second point is that PJM needs significant coal-fired generating capacity to ensure the grid is resilient against at least one of many possible HILF events. Last, grid operators should find a way to properly value the resilience benefits of baseload coal-fired electric generating capacity.

May 31, 2017

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[i] PJM Interconnection, *PJM's Evolving Resource Mix and System Reliability*, March 30, 2017. ("*PJM Report*")

[ii] Other resources are fixed amounts of demand response, hydroelectric power, and oil-fired generating capacity.

[iii] PJM determined that 98 portfolios were desirable because they showed high levels of reliability under four operational scenarios: normal peak conditions, light load, extremely hot weather, and extremely cold weather.

[iv] Sixty-three desirable portfolios were comprised of at least 20% coal-fired generating capacity, and 43 portfolios were comprised of at least 30% coal-fired capacity.

[v] PJM RTO, "Capacity by Fuel Type," 2016. Gas comprised 34% of the region's generating capacity and nuclear 19%.

[vi] Over the period 2010 – 2016, 23,652 MW of coal-fired generating capacity within the PJM region had retired. An additional 8,633 MW have announced plans to retire.

[vii] *PJM Report* page 32.

[viii] *PJM Report* page 34. Such events include risks associated with cybersecurity, other extreme weather events, and increasing dependence on natural gas pipelines. Other experts have identified and analyzed additional potential risks such as extreme solar weather, pandemics, and detonation of a high-altitude nuclear device resulting in an electromagnetic pulse. However, these analyses were conducted before substantial coal retirements had begun and reliance on natural gas had increased significantly.

[ix] PJM report, page 5, footnote 16, states that "[r]esilience, in the context of the bulk electric system, relates to preparing for, operating through and recovering from a high-impact, low-frequency event. Resilience is remaining reliable even during these events." Other organizations have defined resilience in a similar manner. For example, NARUC defines resilience as "the robustness and recovery characteristics of utility infrastructure and operations, which avoid or minimize interruptions of service during an extraordinary and hazardous event."

[x] Nineteen of 34 resilient polar vortex portfolios were comprised of at least 30% coal-fired generating capacity.

Attachment 2: IHS Markit, "Ensuring Resilient and Efficient Electricity Generation"

IHS Markit™

Ensuring Resilient and Efficient Electricity Generation

The value of the current diverse US power supply portfolio

September 2017

Lawrence Makovich
Vice President and Chief Power Strategist

James Richards
Consulting Principal

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The value of the current diverse US power supply portfolio

About the report

Ensuring Resilient and Efficient Electricity Generation: The value of the current diverse US power supply portfolio from IHS Markit utilizes the company's extensive knowledge and proprietary models of the interaction between regional power system demand and supply to assess the impact on consumers and the US economy of current trends moving the US power sector toward a significantly less efficient mix of fuels and technologies for power production. The retail price impacts from wholesale power market distortions provide the inputs into IHS Markit macroeconomic models to generate the national impacts to US household disposable income, employment, and GDP growth. This research was supported by the Edison Electric Institute, the Nuclear Energy Institute, and the Global Energy Institute at the US Chamber of Commerce.

IHS Markit is exclusively responsible for all of the analysis and content.

Ensuring Resilient and Efficient Electricity Generation

The value of the current diverse US power supply portfolio

Executive summary

Current US consumers benefit from a reliable, resilient, and cost-effective electric supply portfolio that employs a diverse set of generating technologies and fuel sources. Quite simply, not having all of the nation's eggs in one basket makes a power supply portfolio a cost-effective risk management strategy, because the short-run price and deliverability excursions from normal conditions, the longer-run fuel price cycles, and the infrastructure development and deliverability constraints are not highly correlated through time across generating technologies and fuel sources.

US consumers paid $381 billion for the reliable and resilient grid-based electricity that they consumed in 2016. At the same time, consumer purchasing decisions revealed that consumers valued the electricity at more than twice the amount that they paid for it.

Maximizing the US electricity consumer net benefit (the value to consumers of electricity beyond what they pay) requires producing the reliable electricity that consumers want, when they want it, at the lowest possible cost, and with a power supply portfolio that is resilient to the dynamic power production operating environment. Achieving this objective is challenging because the electric production operating environment is complex and difficult to anticipate. The energy inputs into electric generation—natural gas, coal, uranium, oil, flowing water, wind speed, and solar irradiation—involve price uncertainties and availability risks. The prices and availability of these inputs are difficult to predict. They are prone to short-run variability and longer-run multiyear price cycles; and they are also subject to low-probability but high-impact constraints on deliverability, such as weather events, like the polar vortex or Hurricanes Sandy and Harvey, and infrastructure failures, like the Aliso Canyon natural gas storage outage or the Texas Eastern Transmission natural gas pipeline failure. The good news is that the diverse US power supply portfolio has proven resilient to significant deviations from normal operating conditions in the past.

But here is the rub: this ability to reduce the magnitude and duration of disruptive events is often taken for granted and is at increasing risk of eroding. The grid-based electricity supply portfolio in the United States is becoming less cost-effective, less reliable, and less resilient owing to a lack of harmonization between federal and state energy policies and wholesale electricity market operations. Policy-driven market distortions are delaying market adjustments to achieve a reliable long-run demand and supply balance, suppressing market-clearing wholesale electricity prices and reducing market-based generator cash flows. Consequently, some power plants that are critical to maintaining reliable, resilient, and efficient electric supply are retiring before it is economic to do so; and this acceleration in the turnover of the US electric supply portfolio is moving the United States toward a less cost-effective, less resilient, and less reliable power generation mix. The nation's electric reliability watchdog, the North American Electric Reliability Corporation, observed, "Premature retirements of fuel secure baseload generating stations reduces resilience to fuel supply disruptions."[1]

Within the next decade, a "less efficient diversity" portfolio case could characterize some US power systems. Such a case involves no meaningful contributions from coal or nuclear resources, a smaller contribution from hydroelectric resources, and a tripling of the current 7% contributions from intermittent resources, with the remaining majority of generation coming from natural gas–fired

1. North American Electric Reliability Corporation, *Synopsis of NERC Reliability Assessments: The Changing Resource Mix and the Impacts of Conventional Generation Retirements*, May 2017.

resources. This less efficient diversity portfolio case also likely results in little or no reduction in electric sector carbon dioxide (CO_2) emissions because the CO_2 emissions profile of the prematurely retiring power supply resources is less than or equal to the emissions profile of the replacement power resources.

Comparing the expected industry performance in the less efficient diversity portfolio case with the actual industry performance in recent years quantifies what is at stake if nothing is done to arrest the erosion in the cost-effectiveness, resilience, and reliability of the current US power supply mix. A comparison of the current US electric supply portfolio outcomes from 2014 to 2016 with analyses of the expected outcome from the less efficient diversity portfolio case indicates that

- The current diversified US electric supply portfolio **lowers the cost of electricity production by about $114 billion per year and lowers the average retail price of electricity by 27%** compared with the less efficient diversity case.
- Avoiding the consumer adjustment to the higher retail prices in the less efficient diversity case preserves current levels of electric consumption and **avoids an annual $98 billion loss in consumer net benefits** from electricity consumption.
- The resilience of the current diversified US electricity portfolio to the delivered price risk profile of the fuel inputs to electric generation **reduces the variability of monthly consumer electricity bills by about 22%** compared with the less efficient diversity case.
- Preventing the erosion in reliability associated with a less resilient electric supply portfolio **mitigates an additional cost of $75 billion per hour** associated with more frequent power supply outages that add to the current US average expected outage rate of 2.33 hours per year.

Comparing the broader economic impacts of the less efficient diversity case with the IHS Markit baseline simulations of the US economy indicates the following US macroeconomic impacts within three years of the retail price increase:

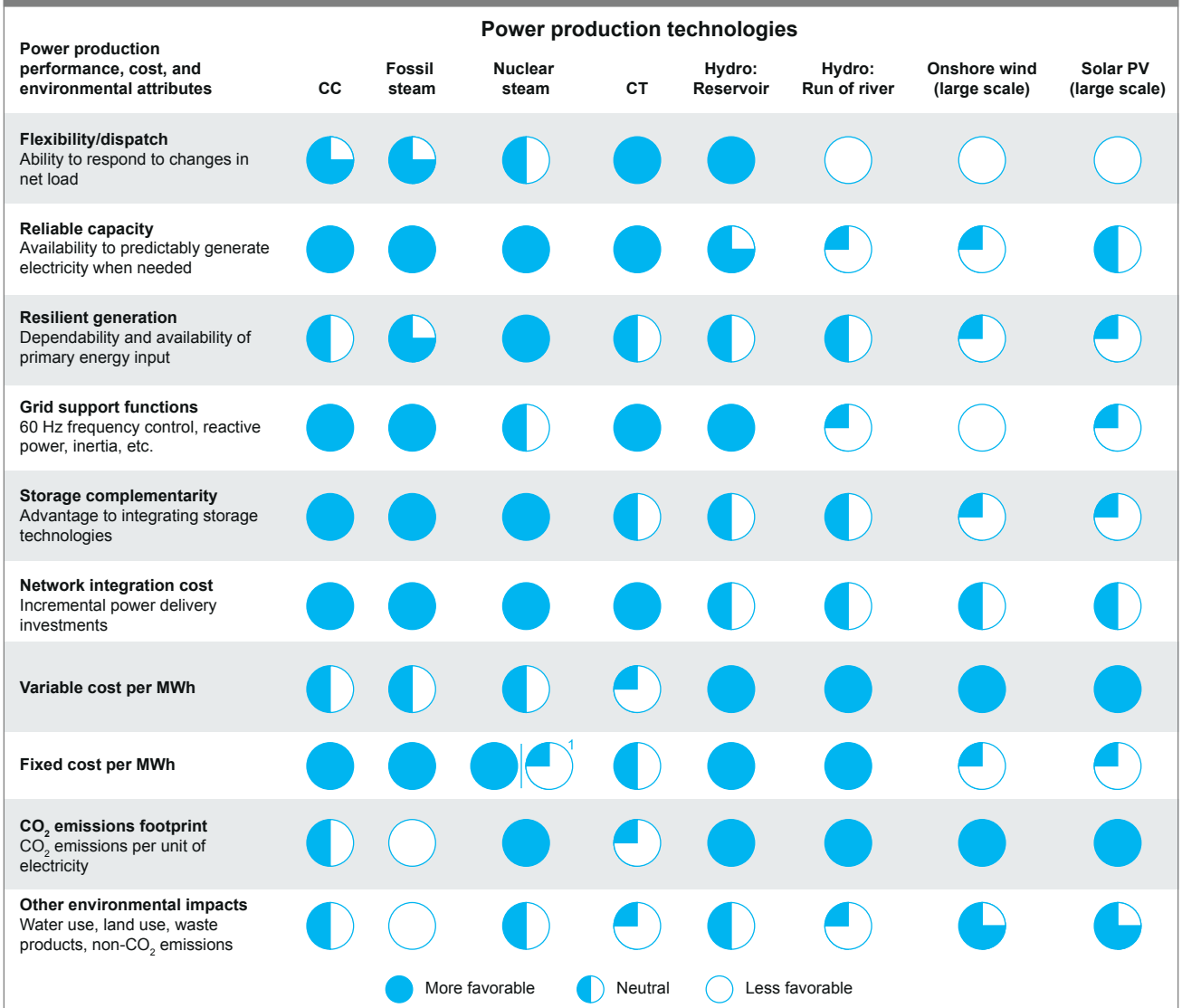
- The 27% retail power price increase associated with the less efficient diversity case causes a **decline of real US GDP of 0.8%, equal to $158 billion** (2016 chain-weighted dollars).
- Labor market impacts of the less efficient diversity case involve a reduction of **1 million jobs**.
- A less efficient diversity case **reduces real disposable income per household by about $845 (2016 dollars) annually**, equal to 0.76% of the 2016 average household disposable income.

Engineering and economic analyses consistently show that integration of different generating technologies and fuel sources supports a reliable, resilient, and efficient electricity supply. The current state of electric production technology reflects a long-standing characteristic that no single generating resource type or fuel source can reliably supply all segments of consumer demand at the lowest cost per kilowatt-hour. Existing electric production technologies bring different cost and operating characteristics to an electric supply portfolio (see Figure 1). A mix of these characteristics enables cost-effective generation and stable grid operation. Complementary technologies can alter these relative cost and performance characteristics. For example, economic electric storage technologies help to manage intermittent generation resource production patterns and can improve power system net-load factors to take greater advantage of cost-effective, high-utilization generating resources in the portfolio.

An efficient power supply portfolio requires alignment of the most cost-effective generating technologies to each segment of consumer demand and a focus on overall power system supply costs. US electric

Figure 1

Performance, cost, and environmental attributes of power production technologies



1. The first symbol refers to the fixed costs associated with existing nuclear facilities; the second symbol refers to fixed costs associated with new nuclear facilities.
Note: CC = combined cycle; CT = combustion turbine; PV = photovoltaic.
Source: IHS Markit

system demand profiles reflect consumer preferences to use different amounts of electricity at different times throughout the year. The recurring annual hourly consumption patterns for grid-based electricity is about evenly split between the stable 24 by 7 by 52 segment of consumer electric loads—the base load—and the segment of consumer demand that varies between the base-load and peak-load levels throughout the year. The PJM power system provides an example where the minimum aggregate hourly consumer load times the 8,760 hours in the year accounts for 60% of the annual electricity consumption.

A reliable, resilient, and efficient power supply portfolio comprises a diverse mix of generating technologies and fuel sources, involving a cost-effective generation share for flexible generating technologies, intermittent renewable technologies, and high-utilization power plants that supply the base-load segment of consumer demand at the lowest possible cost.

Six key insights guide an understanding of the composition of a cost-effective electric supply portfolio:

- **Cost-effective power supply requires integrating a diverse fuel and technology supply mix.** A cost-effective electric generating supply portfolio integrates available technologies to achieve the lowest overall cost to generate electricity aligned with the segments of aggregate consumer demand defined by the recurring time pattern of electricity usage throughout the year.

- **A reliable, resilient, and efficient supply portfolio requires diverse power supply rather than maximum diversity.** A cost-effective power supply portfolio will typically include some, but not necessarily all, of the available electric generating technologies. Diversity is necessary for reliability, resilience, and efficiency, but a reliable, resilient, and efficient portfolio does not maximize supply diversity by incorporating as many technologies as possible in equal generation shares.

- **System efficiency trumps individual plant efficiency.** Integrated power supply optimization differs from individual generating resource optimization. An efficient power system outcome does not necessarily involve all resources operating at their most efficient stand-alone utilization rates to achieve the minimum possible individual plant levelized cost of energy production. Power system utilization of generating technologies below their stand-alone maximum efficiency rate is not a source of economic inefficiency, because the efficiency objective is at the power system level rather than the individual plant level.

- **A cost-effective mix of generating resources does not need the same level of operating flexibility in each resource.** Greater operational flexibility is not always cost-effective, because the majority of aggregate power system net load involves a steady, constant base net load.

- **Incorporating grid-based electricity storage likely increases base net-load requirements.** Optimizing economic storage in power supply favors meeting the ups and downs in demand from inventory and producing output from high-utilization production technologies. As a result, more grid-based storage will not necessarily improve the cost and performance of low-utilization, intermittent resources relative to the high-utilization, base-load resources.

- **Environmental policy initiatives can harmonize with market operations.** Formulating policy approaches to appropriately balance benefits and costs can alter, but not distort, the operation of a well-structured wholesale electricity market.

Roughly half of the US electricity sector relies on the regulated process of integrated resource planning to determine the cost-effective power supply portfolio mix. The other half of the US electricity sector relies on wholesale electricity markets to produce market-clearing price signals that coordinate the disaggregated investment decisions in the marketplace to produce a cost-effective electric supply portfolio.

The lack of harmonization between policy initiatives and wholesale electricity market operations distorts wholesale electricity market-clearing prices. A problem exists because an accumulation of federal and state subsidies and mandates for specific technologies causes generation shares for these technologies to exceed the shares associated with a reliable, resilient, and efficient electric supply portfolio. Such initiatives are at odds with the market price signals produced by a well-structured wholesale electricity market that coordinate the development of the resource mix associated with a reliable, resilient, and cost-effective supply portfolio.

Subsidies for specific generating technologies do not reduce, but rather shift, some of the cost of specific electric generation technologies. Federal subsidies shift some costs from consumer power bills to current or future consumer tax bills. In addition, some state subsidies shift costs from consumers with distributed generation resources to those without. Since subsidies shift costs, the result is the development of more

subsidized resources than are cost-effective with a level playing field. As a result, an economic rationale exists for market interventions to offset the unintended consequences of the uneven playing field.

Wholesale electric market distortions are the unintended consequences of the lack of policy and market harmonization. The recurring extensions of federal subsidies and the persistent ratcheting up of state renewable resource mandates continue to delay market adjustments to restore demand and supply balances in some regional power systems. In addition, these policies increase the amount of zero–variable cost supply resources beyond the cost-effective generation shares and thus suppress wholesale electricity market prices from the levels expected in an undistorted market outcome. Further, these market distortions shift the supply portfolio and increase the exposure to risk factors that cause potential deviations from normal operating conditions.

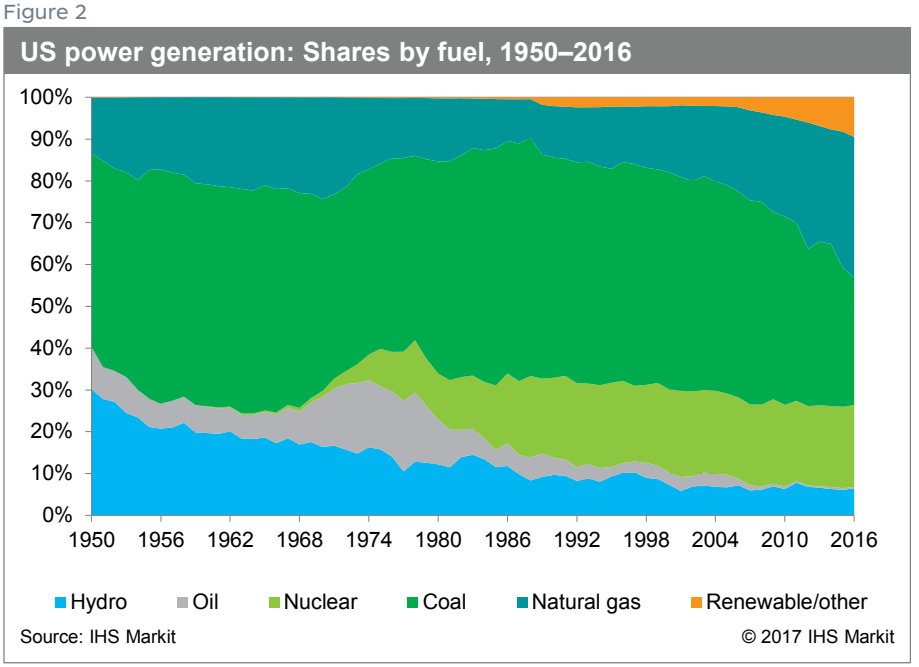
Adjusting the utilization of electric supply resources throughout the grid to address risk factors is central to the security-constrained dispatch of the power supply to meet aggregate consumer demand. The cost of the security of supply adjustments increases with greater exposure to risk factors. And the increasing cost of ensuring power system resilience is exposing the problem that some current wholesale market price formation rules do not fully compensate generating resources for providing the desired power system supply resiliency. The most extreme cases occur when generating resources providing security of supply receive negative market-clearing prices because distorted market conditions drive rival subsidized suppliers to bid against each other to avoid the loss of output-based subsidy payments.

Wholesale electric market price suppression and higher uncompensated operating costs reduce generator cash flows compared with the expected undistorted market outcome. These market distortions continue to undermine competitive power plant investment pro forma. The results are the prolonged cash flow shortfalls associated with competitive generator supply investments.

Many federal and state subsidies and mandates seek to reduce CO_2 emissions by actively promoting specific forms of electric generation over others, and the result is often at odds with the objective. In particular, nuclear power resources are similarly situated to other non–CO_2-emitting resources such as wind, solar, and geothermal in the supply portfolio. However, policies that suppress market-clearing prices cause disproportionate cash flow suppression for the high-utilization generating technologies required to cost-effectively supply the stable, constant base-load segment of aggregate consumer electric demand. As a result, wholesale price suppression disproportionately harms the non–CO_2-emitting nuclear power resources and causes premature retirement and replacement by a mix of renewable and natural gas resources with a higher CO_2 emission profile.

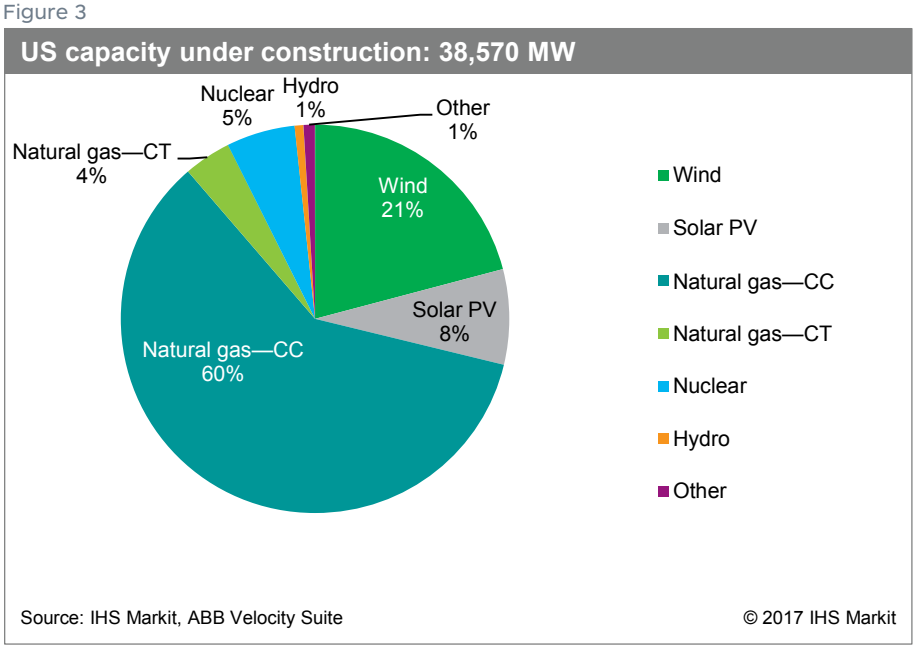
The current US electric supply portfolio is made up of a diverse mix of generating technologies and fuel sources (see Figure 2). The current trend in the US power supply portfolio is toward a greater reliance on natural gas–fired generating resources and intermittent renewable resources and a diminished role

Figure 2



for hydro, oil, nuclear, and coal-fired generation.

Figure 3



Natural gas–fired technologies account for 64% of the current electricity capacity addition pipeline, and wind and solar capacity additions account for another 29% of the pipeline of new supply (see Figure 3). The expected utilization rates of the natural gas–fired technologies are more than twice those of the intermittent resource additions. Therefore, if current trends continue over the next decade, the majority of generation in the US supply portfolio will start to come from the security-constrained power system dispatch of natural gas–fired generating technologies; this capacity will be operating in a net load–following mode to back up and fill in for a policy-driven threefold increase (from the current 7% level) of the intermittent wind and solar generation share as the generation shares of hydro, nuclear, coal, and oil continue to diminish.

The move toward more natural gas–fired generation is consistent with the shale gas innovation-driven decline in the relative price of natural gas, creating a competitive advantage for natural gas–fired generating technologies in the marketplace. However, the improving relative cost of natural gas–fired generating technologies in the marketplace has not produced what one expects in an economics textbook marketplace: the orderly economic replacement of unprofitable, obsolete generating technologies with new, profitable state-of-the-art natural gas–fired generating technologies. Instead, market distortions are undermining investments in natural gas–fired generation technologies and producing bankruptcies and billions of dollars of natural gas–fired generation asset write-downs.

Evaluating the consequences of current trends requires understanding the economic and engineering principles governing the makeup of a reliable, resilient, and efficient electric supply portfolio. Applying these principles indicates that the current US power supply portfolio is moving away from the cost-effective mix of fuels and technologies and toward a less reliable, less resilient, and less cost-effective power supply portfolio.

Current trends reflect the lack of harmonization between policy initiatives and market operations that causes disorderly market development. Timely market price signals are key to long-run market efficiency, because the efficient timing of market entry for electricity supply involves multiyear-long lead times for power plant development that require anticipation of future demand and supply balance points. Market distortions that suppress market-clearing prices from what demand and supply conditions would otherwise produce interfere with the dynamic process, whereby consumer and supplier adjustments in an efficient marketplace resolve demand and supply imbalances and pace efficient investment.

Harmonization of environmental policy goals and market operations is possible. But undoing existing market distortions will take time under the best of circumstances. Meanwhile, implementing market

interventions to offset existing distortions can mitigate the consequences of existing market distortions. In particular, defining criteria for power system resilience and implementing reforms to wholesale electricity price formation or making out-of-market payments for resilience can avert underinvestment in cost-effective electric supply technologies that provide the reserves needed for resilience against the most significant potential disruptions to normal power system operations and prevent the premature retirement of generating resources that cost less to operate than to replace.

Three years ago, the IHS Markit study *The Value of US Power Supply Diversity* warned that complacency regarding wholesale market distortions would lead to erosion in the value of the US power supply portfolio.[2] Unfortunately, the assessment proved accurate as competitive electric generator cash flow shortfalls persisted and a series of premature retirements of otherwise economic base-load power plant retirements unfolded, mitigating some of the retail price declines available from cyclically low fossil fuel costs, and leading to less power system resilience and the perverse increase in CO_2 emissions in some regional power systems.

Awareness is growing regarding the accumulating costs of the lack of harmonization between federal and state policies and electricity market operations. In May 2017, the Federal Energy Regulatory Commission (FERC) conducted a technical conference to garner input on possible approaches to harmonize state electricity policy initiatives with the federal objective of enabling efficient market operations. Earlier this year, the US secretary of energy asked for an assessment of the impact of current electricity market conditions on the efficiency and reliability of US power supply.[3] In August 2017, the US Department of Energy (DOE) released the Staff Report to the Secretary on Electricity Markets and Reliability. Secretary Perry's press release on the study noted,

> It is apparent that in today's competitive markets certain regulations and subsidies are having a large impact on the functioning of markets, and thereby challenging our power generation mix. It is important for policy makers to consider their intended and unintended effects.[4]

The DOE report includes policy recommendations to expedite FERC and regional transmission organization/independent system operator efforts to reform wholesale energy price formation as well as define and support utility, grid operator, and consumer efforts to enhance system resilience.

Former Secretary of Homeland Security Tom Ridge warned that, "Only a grid built on diverse and stable sources of energy can withstand evolving threats and keep the lights on throughout America."[5]

This IHS Markit study responds to these growing concerns and to the DOE Staff Report recommendations for further research into reliability and resilience with resource diversity assessments as well as further research into market structure and pricing with assessments of the underrecognized contributions from base-load power plants.

The challenge of harmonizing policy initiatives and market operations puts the US power sector at a critical juncture. Doing nothing likely results in higher and more varied monthly power bills, reflecting less reliable and less resilient power supply in the decades ahead, compared with doing something that preserves the consumer net benefits generated by a more reliable, resilient, and cost-effective US electric supply portfolio.

2. See the IHS Markit study, The Value of US Power Supply Diversity.

3. Secretary of Energy Rick Perry, Memorandum to the Chief of Staff, 14 April 2017, Subject: Study Examining Electricity Markets and Reliability.

4. Secretary of Energy Rick Perry, Press Release, 23 August 2017, retrieved 24 August 2017.

5. Tom Ridge, "Keep nuclear in the nation's energy mix," Philly.com, 9 August 2017, retrieved 24 August 2017.

Ensuring Resilient and Efficient Electricity Generation

The value of the current diverse US power supply portfolio

Lawrence Makovich, Vice President and Chief Power Strategist

James Richards, Consulting Principal [6]

Overview

US consumers benefit from large-scale, grid-based electric supply produced by a diverse portfolio of generating technologies and fuel sources. Three years ago, IHS Markit conducted a study of the value of the grid-based US power supply diversity. The study was in response to concerns that the reliability, resilience, and cost-effectiveness of the existing diverse generating technology and fuel mix in the US power portfolio was being taken for granted, and that complacency regarding the unintended consequences of the lack of harmonization between policies and market operations was causing electric wholesale market price suppression, premature retirement of otherwise economic power plants, and an increasing exposure of US power supply to the price and deliverability risks associated with a greater reliance on natural gas–fired generation.

In the past three years, the disharmony between public policies and market operations has worsened and devalued the US electric supply portfolio. Increasingly, the US electricity supply is being shaped by subsidies and mandates for favored technologies and fuel sources based on flawed cost assessments typically involving simple levelized cost analyses that ignore the power supply cost implications of balancing electricity demand and supply in real time. Consequently, US power supply continues to shift away from a reliable and cost-effective portfolio of generating technologies and fuel sources with the resilience to manage electricity production risk factors that enable the US power supply portfolio to provide US consumers with the grid-based electricity that they want and when they want it.

In light of many changes and new developments, this study takes a fresh look at what is at stake for US consumers if the US power supply portfolio continues to move toward a less efficient and resilient diversity end state involving little or no coal, oil, or nuclear generation; diminished hydroelectric generation; and mandated subsidized renewable wind and solar photovoltaic (PV), tripling from the current 7% generation share. In this scenario, the majority of generation would come from natural gas–fired technologies operating in a net load–following mode to back up and fill in for intermittent generating resources.

In the past three years, renewable policy initiatives have moved from supporting a minimum level of activity intended to generate enough scale in development to help move up the renewable generation learning curve, to supporting state initiatives mandating a transition to 50–100% renewable generation within 13–23 years. This ratcheting up of renewable policy goals has already created costly power system operating challenges in places that are approaching the profile of the less efficient diversity power portfolio case.

California is a harbinger of the devaluation in reliable, resilient, and efficient power supply portfolios. From 2002 to 2016, California has moved toward the less efficient diversity electric supply profile. California reduced in-state coal- and oil-fired generation by 88% and currently has little or no coal- and oil-fired generation in the mix, and nuclear power has declined 45% and is scheduled to be eliminated within a few years. Hydroelectric generation is trending downward, while the generation shares of

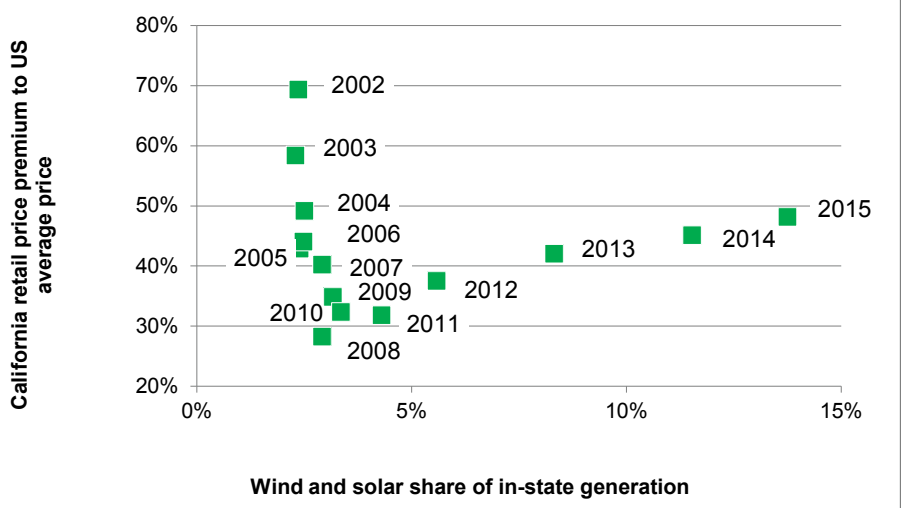
6. Douglas Giuffre, Director; Alex Klaessig, Associate Director; and Benjamin Levitt, Associate Director, contributed to this report.

intermittent wind and solar increased from 2% to 16% and the natural gas–fired generation share increased from 50% to 61%. Current power system operations involve natural gas–fired capacity operating with an average plant factor of 26% in an inefficient net load–following mode to back up and fill in for the intermittency of the renewable generation. In addition, power supply resiliency has diminished across the past decade owing to the exposure to natural gas supply infrastructure risks brought to light by the recent outage of the Aliso Canyon natural gas storage facility.

Beyond the increased risk exposure, moving toward a less efficient diversity supply portfolio is also proving costly. California retail electricity prices declined in the aftermath of the 2000–01 California electricity crisis (see Figure 4). But the retail price trend reversed as California energy policy created discord with market operations and accelerated the move toward less efficient diversity in power supply by ratcheting up wind and solar generation shares beyond the level associated with a reliable, resilient, and efficient power supply portfolio. This policy and market discord contributed to California retail electricity prices increasing faster than the US average over the past five years and reaching a 50% premium to the US average retail price in 2016.

Figure 4

California power sector: Generation share of wind and solar and retail price premium to US average, 2002–15

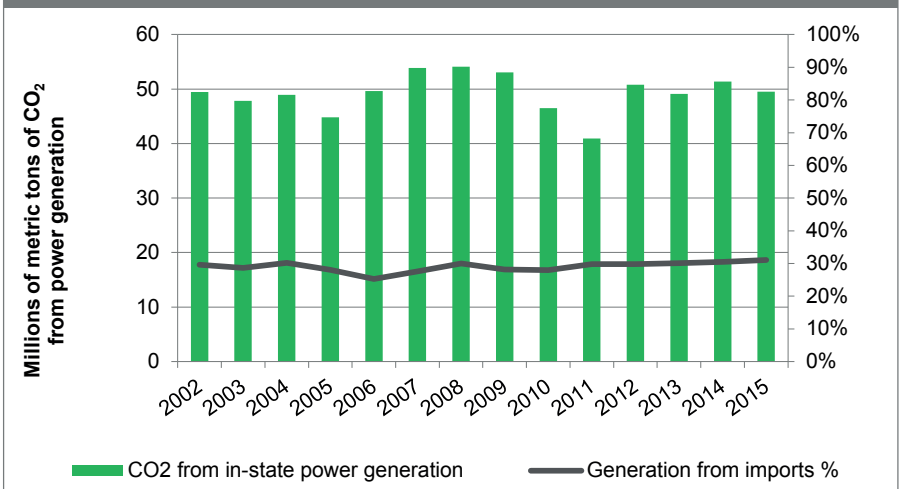


Source: IHS Markit, ABB Velocity Suite

California employed command and control policy initiatives to increase the generation share of wind and solar resources in response to climate change concerns. Yet the command and control climate policy initiatives did not produce a declining trend in the carbon dioxide (CO_2) emissions associated with the two-thirds of electric supply coming from the in-state electric generation resource mix since 2002, when California mandated its first policy objectives for future renewable generation shares (see Figure 5).

Figure 5

California in-state power generation CO_2 emissions and out-of-state electricity imports (2002–15)



Source: IHS Markit, California Air Resources Board

California's lack of harmonization between policy initiatives and market operations illustrates the underlying problem of a lack of consensus

regarding power system objectives. In the past three years, the concept of "base-load" electricity demand and supply has become controversial, and using the term is increasingly becoming a litmus test regarding power system objectives. From the consumer perspective, cost-effective high-utilization power supply technology aligned with the base-load segment of demand is still critical to efficiently producing reliable and resilient electricity supply. From the perspective of wind and solar advocates, a focus on maintaining cost-effective base-load supply is an obstacle to increasing the generation shares of wind and solar resources. Along these lines, a recent Brattle Group report sponsored by the National Resources Defense Council argues that, "the term 'baseload' generation is no longer helpful for purposes of planning and operating today's electricity system."[7]

California is on the leading edge of the move to less efficient diversity in power supply, but the United States is also heading in the same direction. In the three years since our initial study, the US natural gas generation share increased and made natural gas–fired generation the leading generation source in the United States, with some power systems now relying on natural gas for the majority of their power supply. In the past three years, the delivered price of natural gas has remained uncertain and difficult to predict owing to numerous cyclical drivers and periodic events that have generated price spikes. On 21–22 January 2014, the delivered price of natural gas at key Northeast delivery hubs—Algonquin and Transco Zones 5 and 6—reached $55–120/MMBtu. The fuel delivery disruptions during the 2014 polar vortex and the delivery constraints following the April 2016 Texas Eastern Transmission pipeline failure in Pennsylvania drove home the need to manage the risks of natural gas price spikes and delivery constraints with a diversified electric supply portfolio. In just the past three years, the US annual average delivered price of natural gas to power generators was as high as $5.00/MMBtu and as low as $3.15/MMBtu.

This study updates the assessment of what is at stake in the US electricity sector from the increasing lack of harmonization between federal and state policy initiatives and electricity market operations. This study follows the evolution of concerns across the past three years that the power sector polices are increasingly driving a shift away from the economic and engineering principles that shape cost-effective power supply portfolios. Therefore, this study reviews what constitutes a cost-effective power supply portfolio and illustrates the flaws associated with policy initiatives based on simple time-ignorant levelized cost of energy (LCOE) comparisons of generation resources.

Understanding market distortions generated by the discord between federal and state policy initiatives and market operations and realities requires understanding what the outcome of a well-functioning electricity market looks like in the first place. Therefore, this study also reviews how a well-structured electricity market harmonized with principled regulation can produce the wholesale price signals that shape a cost-effective power supply portfolio—including an outcome that fully internalizes environmental costs. This efficient market outcome provides the basis to examine the market distortions caused by the mandates of subsidized renewable resources beyond their cost-effective generation shares and the impact of unresolved security-constrained wholesale price formation shortfalls.

Although the initial study pointed out that the impact of diversity in power supply was not the same across all technologies, the policy debate often simply focuses on diversity as a metric for power supply. Therefore, this study tries to reiterate that the consumer-driven objective is to appreciate and preserve the generating technology and fuel diversity that provides reliable, resilient, and cost-effective power supply. Consequently, the objective is not to maximize power supply diversity by employing, as much as is possible, all available electric supply options in equal generation shares. Such a maximum diversity portfolio would not maximize reliability, resilience, or cost-effectiveness.

7. The Brattle Group, *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*, 26 June 2017, retrieved 24 August 2017.

The examination of the current market distortions provides insights into available and appropriate corrective actions. The most straightforward solution is to eliminate policy initiatives that cause significant market distortions. However, implementing such an approach to harmonize policy initiatives and market operations may be politically unfeasible. Therefore, corrective actions require regulatory approval and implementation of policies that produce offsetting impacts to the market distortions that support the cash flows of the generating resources required for reliable, resilient, and cost-effective power supply. These offsetting market interventions can provide payments for resilience attributes. Such offsetting market interventions, along with market rule changes to align marginal generating costs to security-constrained price formation, can together help preserve the net benefits to US consumers of a more reliable, resilient, and cost-effective power supply portfolio.

The net benefit to US electricity consumers from current grid-based power supply

In 2016, the 143 million electricity consumers in the United States consumed 3,711 billion kWh of grid-based power and paid an average retail price of 10.28 cents per kWh. Average residential prices ranged from 9.11 cents to 27.46 cents per kWh across the 50 US states, while commercial and industrial prices ranged from 7.47 cents to 24.64 cents and 4.53 cents to 20.70 cents per kWh, respectively. Consumer electricity purchasing decisions across these three consumer segments, over the observed range of prices, and across all states revealed that US consumers valued the electricity that they consumed at more than twice the $381 billion that they paid for it.

Consumers reveal the value that they place on different amounts of electricity purchased from the grid by the choices that they make when the price of electricity changes. For example, when the electricity price goes up, consumers choose to forgo buying some of the electricity that they purchased at the lower price, because the value of some electricity consumption is not worth the higher price. In this case, consumers choose a new level of electric consumption and reveal that the electricity they continue to consume is valued as much, or more than, the new higher price. Therefore, analyses of consumer behavior that can quantify how much less electricity consumers will purchase at higher and higher price levels provide a method to measure the value that consumers place on different segments of electricity usage. Appendix I explains the statistical analyses of the long-standing differences in electricity retail price and consumption levels across states and consumer segments that enabled the quantification of the revealed consumer willingness to pay for different segments of electricity use, while accounting for the differences in all the other variables that influence electricity consumption levels.

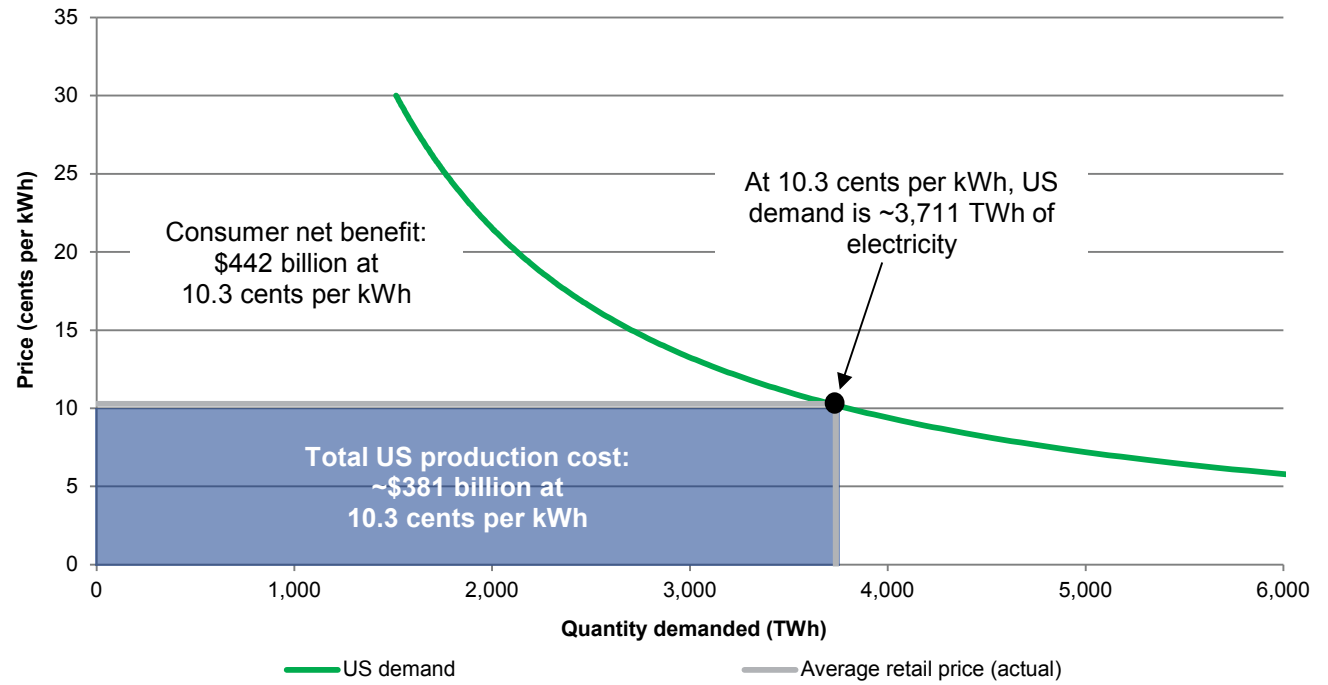
Analysis of consumer electric consumption patterns allows estimation of the relationship between the amounts of electricity that consumers purchase and different price levels—a relationship illustrated by the aggregate grid-based electricity demand curve. Figure 6 shows the estimate of the 2016 US aggregate consumer grid-based electricity demand curve along with the observed 2016 average retail price and the observed level of aggregate consumer electricity consumption.

The area of the rectangle defined by the average retail price times the level of electricity consumption shown in Figure 6 indicates the direct cost of grid-based electricity to consumers. This $381 billion direct cost of electric supply reflected the underlying cost profiles of the diverse generating technology and fuel mix in the existing US power supply portfolio (see Figure 7).

The slope of the US aggregate consumer grid-based electricity demand curve reflects the quantification of the observed reactions in consumer demand to changes in retail prices with all other factors held constant—what economists call the "price elasticity of demand." This demand curve indicates the predictable consumer reaction to reduce electricity consumption when the electricity price increases

Figure 6

US grid-based electricity demand (long-run), 2016

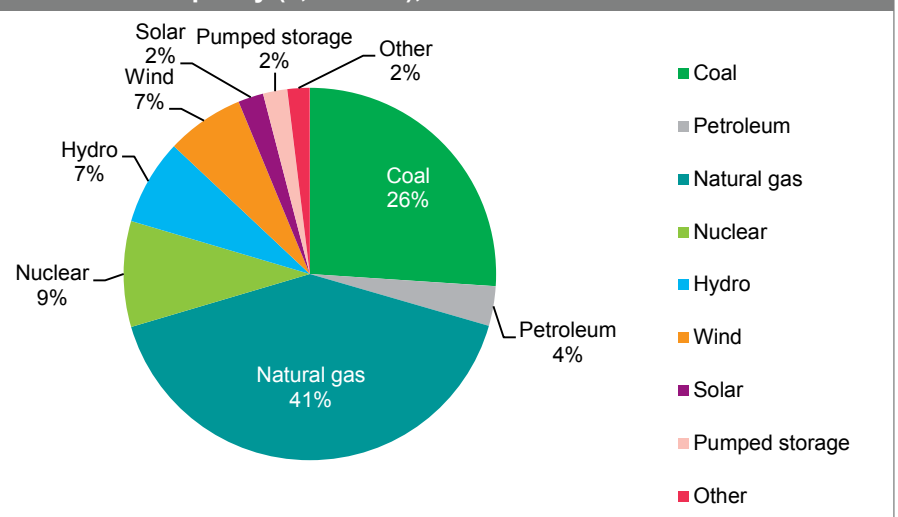


Source: IHS Markit © 2017 IHS Markit

across observed price levels ranging from 4 cents to 30 cents per kWh. As a result, the demand curve provides reliable estimates of electricity quantity movements within this price range. For example, if the average US 2016 retail price of electricity increased to 15.31 cents per kWh—California's average retail price of electricity—then the average US retail price would be about 50% higher. Although it would take several years for the impact of an electricity price increase to fully work through consumer actions, Figure 8 illustrates the eventual predictable long-run reduction in aggregate consumer demand if all of the other conditions in 2016 remained unchanged.

Figure 7

US installed capacity (1,073 GW), 2015



Source: IHS Markit, ABB Velocity Suite © 2017 IHS Markit

The implication of the nationwide California retail price is that consumer reactions in the long run would trigger a predictable move along the demand curve from the 3,711 TWh consumption level to the 2,659 TWh consumption level—with all other conditions held constant. Since the aggregate consumer

electricity demand curve segments electricity use by price level, this 1,052 TWh reduction in consumer electricity purchases reveals that this segment of consumer demand was worth more than $108 billion to consumers (initial price of 10.28 cents per kWh times 1,052 TWh) but not worth the $161 billion (higher price of 15.31 cents per kWh times 1,052 TWh). Similar predictable reductions in electricity consumption at higher prices indicate the value that consumers place on the electricity consumption all along the demand curve. Therefore, the area under the demand curve from the origin to the actual consumption level provides an estimate of the total value that US consumers put on electricity consumption.

The analysis of US consumer demand provides a statistically reliable demand curve across the range of observed retail prices. The shape of the demand curve is less certain for prices outside of this range. For example, the consumer behavior to install backup generation systems reveals the value that consumers place on some electricity consumption at prices well above the range of observed retail prices. Therefore, calculating the area under the demand curve just across the observed range of prices (10.3–30.0 cents per kWh) provides a conservative estimate of the value that consumers put on the electricity that they consume. In 2016, this conservative estimate of the total value that consumers put on electricity consumption was $823 billion. The implication is clear—US consumers valued the electricity that they consumed in 2016 at more than twice what they paid for it.

The consumer net benefit from grid-based electricity consumption is the difference between the value US consumers put on their electricity consumption and the direct retail cost of electricity to consumers. Economics textbooks describe this value of consumption over what consumers have to pay as the "consumer surplus." Figure 6 shows the area that defines the 2016 US electricity consumer net benefit and provides the conservative estimate that the net benefit of electricity that consumers purchased from the grid in 2016 was valued at about $442 billion.

The change in consumer net benefits, rather than the change in the monthly power bill, is a better metric to assess microeconomic consumer impacts from changes in the electricity sector. For example, if the price of electricity increased by 50% and consumers responded by reducing their consumption by 50%, then the end result is that their monthly power bill remains unchanged. However, although the power bill did not change, the consumer is worse off. Similarly, if the increase in electricity prices created a negative macroeconomic impact that reduced overall economic activity and further diminished consumer purchasing power, then the percentage reduction in consumption would exceed the percentage increase in price and monthly power bills would be lower. However, in this case the consumer is in a worse position even though their monthly power bill is lower. Therefore, the change in net benefit from electricity consumption isolates the microeconomic impact on consumers with all other factors in the broader macroeconomy being held constant.

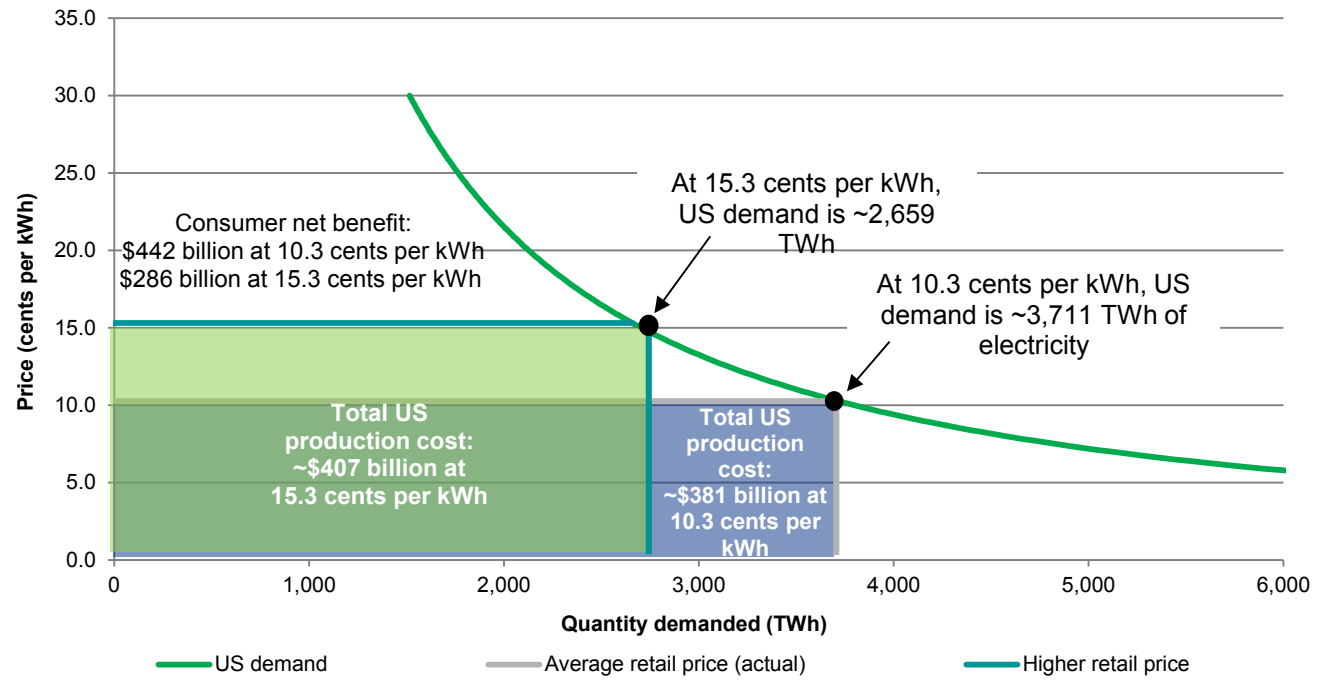
The example of imposing an average retail price increase of 50% to the actual average US retail price in 2016 illustrates how an increase in electricity production costs can reduce the consumer net benefit of electricity consumption. In this case, the 50% retail price increase would cause a 28% reduction in electricity consumption with all else held constant. Consequently, the total direct cost of electricity production would increase by $26 billion and, as Figure 8 shows, reduce the consumer net benefit of electricity consumption by $156 billion.

Table 1 shows the total direct cost to consumers of grid-based electricity supply in 2014–16 along with conservative estimates of the total value that consumers placed on the consumption of grid-based electricity supply and the associated conservative estimates of the consumer net benefit of grid-based electricity supply.

The annual average US consumer net benefit of $448 billion over the recent 2014–16 time frame indicates the current annual value to consumers of the diverse technology and fuel mix in the existing reliable, resilient US electricity supply portfolio. But the implication is clear—maximizing US consumer electricity consumption net benefits requires reliably supplying consumers with the electricity that they want,

Figure 8

US grid-based electricity demand (long-run): 2016, impact of a 50% price increase



Source: IHS Markit © 2017 IHS Markit

when they want it, and at the lowest cost, including the cost of ensuring resilient power supply.

Table 1

US consumer net benefits, 2014–16
(billions of dollars, nominal)

	Revealed consumer electricity valuation	Consumer direct retail electricity supply cost	Consumer net benefit	Ratio of electricity value versus cost
2016	$823	$381	$442	2.2
2015	$842	$391	$451	2.2
2014	$843	$393	$450	2.1

Source: IHS Markit, US Energy Information Administration (EIA) © 2017 IHS Markit

Reliable, resilient, and cost-effective grid-based power supply maximizes consumer net benefits

Nobody wants to pay more than is necessary for reliable and resilient electric service. The vast majority of US households and businesses purchase grid-based electricity because the most cost-effective way to provide reliable and resilient electric service is through large regional power grids that integrate a cost-effective mix of fuels and technologies capable of exploiting the significant available economies of scale in electric production.

Balancing the costs and benefits of reliability and resilience drove power grid expansion in the United States that produced the three geographically large North American AC electrical interconnections—Eastern, Electric Reliability Council of Texas (ERCOT), and Western—that span the US Lower 48. Within these interconnections, power systems synchronize the coordinated real-time balancing of electric demand and supply for the electricity consumers and producers connected by the power system network while ensuring adequate reserves for reliable operations and incorporating operating adjustments to provide the resilience to sustain significant deviations from normal operating conditions.

Current economic and technological trends are reinforcing electric production and network economies of scale and driving power systems toward broader, smarter, and more integrated AC network operations. For example, within the past two decades, the PJM power system expanded from a three-state power pool (Pennsylvania, New Jersey, and Maryland) to its current scope. It now operates the world's largest market-based power system that coordinates the movement of electricity between producers and consumers through all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. Similarly, California is expanding the energy imbalance market in the Western Interconnection to broaden the scope of its short-run power system operations as a first step toward broadening the independent system operator (ISO) geographic scope of operations and planning in the long run.

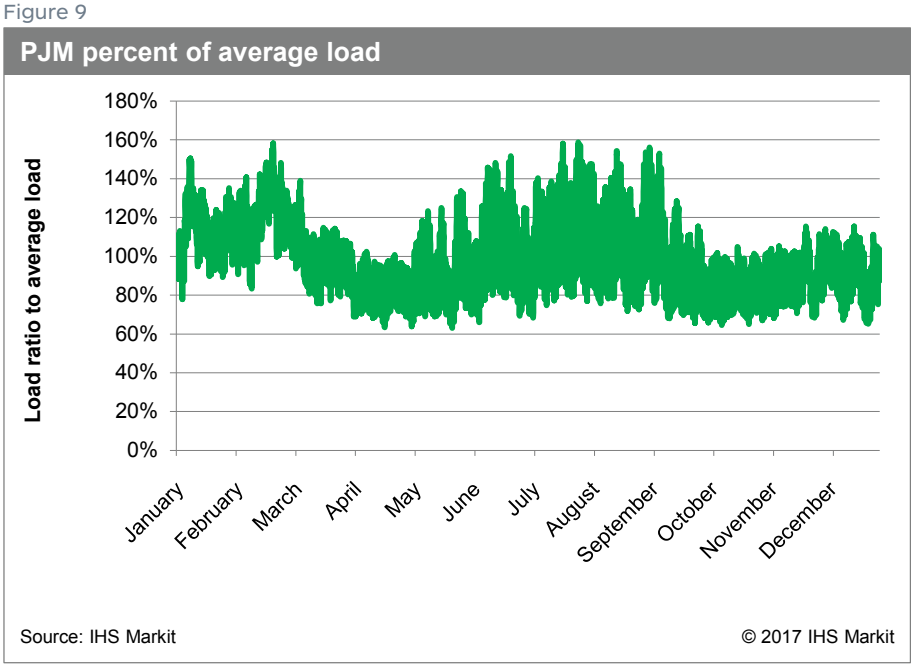
Consumer preferences for electric service shape consumer-driven power system objectives for reliable, resilient, and efficient grid-based power supply

From the consumer perspective, the objective of a grid-based power system is to minimize the cost of reliably balancing power system demand and supply in real time with enough supply resilience to mitigate the potential impact of significant deviations from normal operating conditions in order to provide the electric services that they want, whenever they want them, and at a price that internalizes all costs, subject to the security of supply constraints in an AC power system.

Consumer demands for grid-based electricity reveal a preference to use different amounts of grid-based electricity at different points throughout the year. A number of factors predictably underpin these consumer load patterns throughout the year, such as temperature changes, work schedules, holidays, and hours of sunlight. As a result, the power system aggregate consumer electric demand produces a recurring annual hourly load pattern around the average level of demand involving recurring daily, weekly, and seasonal patterns.

US consumer consumption patterns produce a recurring annual hourly demand pattern for grid-based electricity that is about evenly split between the stable 24 by 7 by 52 segment of consumer electric loads—the base load—and the segment of consumer demand that varies between the base-load and peak-load levels throughout the year. For example, Figure 9 shows the 2015 hourly aggregate consumer demand for grid-based power supply from the PJM network expressed as a ratio to average hourly load.

Figure 9

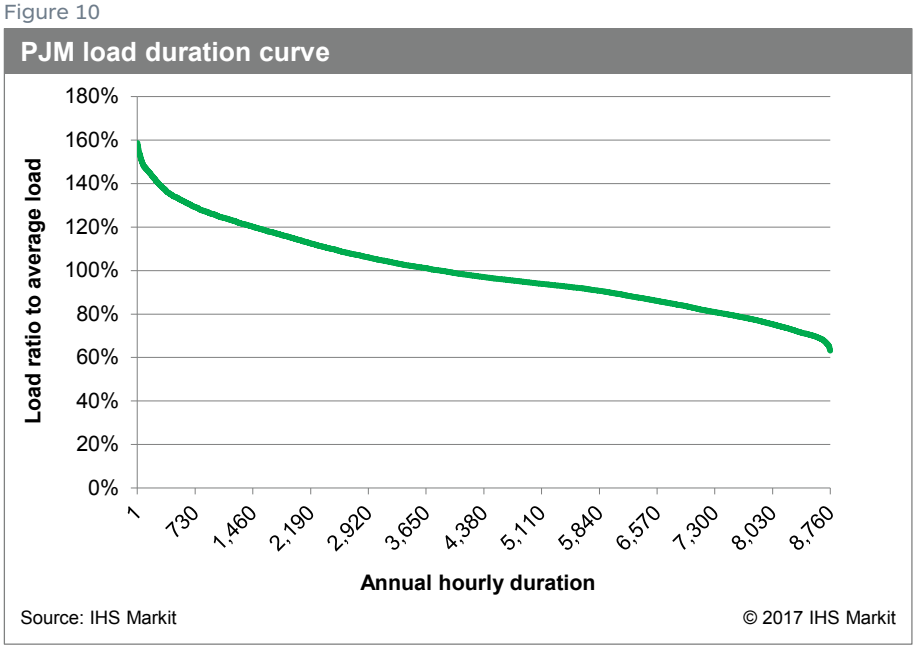


In the PJM example, recurring weather conditions in the winter and summer produce brief periods when aggregate demand is well above average. By contrast, the weather-insensitive consumer uses of electricity underlie the stable, lower-than-average electricity usage levels that define the base of consumer demand throughout the year. In

this PJM example, this aggregate consumer "base-load" demand (equal to minimum load times the 8,760 hours in the year) accounts for 60% of the electricity consumed throughout the year. Hourly power system net load is the aggregate hourly consumer load minus the generation from nondispatchable resources, such as wind and solar outputs. The PJM net-load profile also shows that the base net load accounts for the majority of the dispatchable electric supply.

Expressing power system hourly aggregate consumer demands as ratios to the average load and ordering these load metrics from the highest to lowest ratio produces a power system aggregate consumer annual load duration curve. Whereas an aggregate consumer demand curve segments power system demand by price, a load duration curve segments aggregate consumer demand by time. The load duration curve indicates the percentage of hours across the year associated with different aggregate load levels. Figure 10 shows the example of the PJM load duration curve expressed as a ratio to average load in 2015.

Figure 10



The power system load duration curve translates the consumer preferences to use different amounts of electricity at different points in time into demand segments that can be cost-effectively aligned with available generating technologies and fuel sources.

In addition to revealing a preference to use different amounts of electricity through time, consumers also show a preference for resilient power supply. For example, an interruption in grid-based power supply prevents consumers from using grid-based electricity and thus lowers the consumer's power bill. However, we observe that consumers do not like to generate savings through power outages and are displeased whenever power is restored more slowly than expected after an outage.

Consumers reveal just how highly they value some grid-based electric supply through the choices that they make to preserve critical electric applications from electric service interruptions. Consumer investments in backup generation reveal the upper range of consumer willingness to pay for grid-based electricity consumption. For example, although US grid-based power supply is typically available 99.97% of the time, more than 1 million US residential consumers have chosen to invest in emergency backup generation systems. Such decisions are revealing, because the typical backup generation cost per kilowatt-hour to provide electric service during the 2.33 hours per year of expected grid-based supply disruptions is roughly 100 times the average price of 12.6 cents per kWh that households pay for grid-based power supply. Many commercial and industrial customers—especially customers with critical electric applications in hospitals and data centers—also install backup generation, and these actions reveal similarly high valuations on electricity consumption for critical applications.

Electricity markets incorporate estimates of the revealed consumer willingness to pay to avoid the loss of electric services. For example, in 2014 ERCOT began employing an estimate of the value consumers place

on electric service in its implementation of the operating reserve demand curve (ORDC) real-time electric wholesale market intervention to compensate for the reserves employed to reduce the probability of electric system outages. ERCOT employed an estimate of the value of lost load of $9,000/MWh, a value that was about 100 times the 2015 average retail power price of 8.7 cents per kWh. Electric service interruptions, often caused by severe weather, overloading, power station failures, and other issues, add significant costs to consumers. Prior estimates of total annual power outage costs in the United States have exceeded hundreds of billions of dollars per year.[8] Of course the timing and duration of outages affect consumer impacts, but simply increasing the frequency of the typical electric service disruptions in the United States results in about $75 billion per hour of electric service interruption costs.[9]

The cost of electric outages to consumers drives the consumer demand for resilient power supply. Resiliency is the capability of the power supply portfolio to continue to provide consumers with electric services when operating conditions deviate from normal. For example, a deviation from normal winter conditions occurred on 7 January 2014 in the PJM power system. Polar vortex conditions drove the power system demand for electricity to an all-time high winter peak of 141,312 MW. Abnormal conditions caused significantly higher-than-normal unavailability from natural gas–fired generating units linked, in many cases, to abnormal fuel supply constraints. The diversity in the generation portfolio allowed nuclear power plants and oil- and coal-fired power plants to back up and fill in for the natural gas–fired resource limitations. Since then, the 5,573 MW of coal-fired capacity that provided some of the critical resiliency has been closed, changing the level of resilience to a similar future polar vortex event.[10] Another recent example of power system resiliency challenges is the Aliso Canyon natural gas storage outage. In 2015, this natural gas storage facility was closed because of a leak. This single facility accounted for two-thirds of the natural gas storage in Southern California, and, in addition to providing 17 natural gas–fired generating plants with natural gas during constrained pipeline delivery periods, the storage facility also provided critical natural gas pipeline pressure regulation for the backbone pipeline serving California. The California Independent System Operator (CAISO) found that providing resiliency to this event required relying on imports from the broader, more fuel-diverse power supply portfolio operating elsewhere in the Western Interconnection.

Reducing the probability of outages by increasing the resiliency of a power supply portfolio comes at a cost. Therefore, consumers face a trade-off regarding the cost of increased power supply resiliency and the decreased cost of supply interruptions. A cost-effective trade-off equates the additional cost of increasing power supply resilience with the value of the additional benefit.

The underlying principles shaping reliable, resilient, and cost-effective grid-based power supply portfolios

Reliable and resilient power system operation requires robustly balancing power system demand and supply in real time. The resources available to instantaneously match electric supply and demand involve operable generating capacity as well as grid-level electric storage technologies and demand-side resources. Since the availability of any of these resources is uncertain at any point, providing reliable electric service requires operating with some of these resources in reserve. Therefore, a robust reserve uses diversity of capacity to mitigate potential deviations from normal operating conditions, affecting the availability of a

8. Kristina Hamachi LaCommare and Joseph H. Eto, "Cost of Power Interruptions to Electricity Consumers in the United States," *Energy: The International Journal* 31 (7 April 2005); and Primen, "The Cost of Power Disturbances to Industrial and Digital Economy Companies," TR-1006274 (available through EPRI), 29 June 2001.

9. Michael J. Sullivan, Josh A. Schellenberg, and Marshall Blundell, *Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States*, Ernest Orlando Lawrence Berkeley National Laboratory, January 2015, retrieved 24 August 2017.

10. Matthew L. Wald, "Coal to the Rescue, but Maybe Not Next Winter," *The New York Times*, 10 March 2014, retrieved 24 August 2017.

given generating technology or fuel source. For example, an operating reserve made up entirely of natural gas–fired resources supplied from a common pipeline could provide power supply reliability under normal pipeline operating conditions. However, the reserve would not be resilient to a pipeline disruption. By contrast, a diverse operating reserve consisting of dual-fueled capacity (pipeline natural gas and on-site liquid fuel inventory) would be capable of reliable generation while also being resilient to a potential significant deviation from normal natural gas pipeline operating conditions.

The cost of a resilient reserve increases with the size and diversity of the reserve, whereas the probability and duration of electric outages (and thus the expected costs) declines with the size and diversity of the reserve. This trade-off means that an efficient power system balances the costs and benefits to consumers of different levels of reliability and resilience. As a result, the primary determinant of the overall size of the power system supply portfolio is the net dependable capacity (the expected power plant capacity after adjustments for the risk of disruptions at time of peak) required to deliver the robust cost-effective level of reliability.

An efficient and resilient electric supply portfolio does not involve a single least-cost generating technology sized to reliably meet the maximum aggregate consumer demand plus the reserve. There is no "one-size-fits-all" electric generation technology or fuel source that can reliably meet this peak demand with resiliency to potential deviations from normal operating conditions as well as cost-effectively supply the recurring annual real-time pattern of power system aggregate consumer demand. Alternative generating technologies bring different cost and performance characteristics to a power supply portfolio. Although a simple LCOE metric can indicate that a single generating technology provides the lowest LCOE on a stand-alone basis under a given set of conditions, a cost-effective supply portfolio would not be made up of this technology alone. Such a single-source supply portfolio ignores the time dimension of power supply and potential deviations from normal operating conditions. For example, advances in solar PV technologies continue to lower the stand-alone cost of generating electricity when the sun shines. However, a recent study by the US Department of Energy's (DOE) National Renewable Energy Laboratory finds that about 65% of a typical rooftop solar energy customer's electricity demand is noncoincidental with the electricity generated from their own rooftop PV units.[11] Therefore, if solar PV provided the lowest LCOE compared with other electric supply technologies, a 100% solar PV power supply portfolio would neither be capable of meeting peak demands nor be capable of supplying consumers connected to the grid with the electricity that they want, whenever they want it.

The time dimension of balancing electric demand and supply limits the cost-effective generation share of an intermittent renewable resource such as solar PV. Similarly, a 100% PV power supply would not be robust to deviations from normal operating conditions, such as the predictable reduction in the output of 1,900 utility-scale PV resources in the path of the 21 August 2017 solar eclipse. The US power system resiliency to this event illustrated the value of the current diversified power supply portfolio.

Roughly half of the US electricity sector relies on the regulated process of integrated resource planning to determine the cost-effective power supply portfolio mix. The other half of the US electricity sector relies on wholesale electricity markets to produce market-clearing price signals that incentivize investment in a cost-effective electric supply portfolio. Regardless of the approach, the cost-effective electric supply portfolio involves aligning the most efficient technology and fuel supply options to segments of consumer demand defined by the recurring annual hourly pattern of electric consumption.

Numerous technologies are available to supply electric generating capacity and energy. As Figure 1 shows, each technology brings different performance characteristics to an electric supply portfolio, including

11. Lori Bird, et al., *Impact of Rate Design Alternatives on Residential Solar Customer Bills: Increased Fixed Charges, Minimum Bills and Demand-Based Rates*, National Renewable Energy Laboratory, US Department of Energy, September 2015, retrieved 24 August 2017.

- **Flexibility/dispatch**—the capability to vary electric output to follow net load through time.
- **Reliable capacity**—the capability to provide capacity when needed.
- **Resilient generation**—the security of primary energy input supply chain for electric production. For example, fuel inventory at a plant site increases the security of electric supply from short-run fuel supply chain disruptions.
- **Grid support functions**—the capability to manage grid electricity voltage and frequency, for example, from automatic generation controls.
- **Storage complementarity**—the degree to which linkage to an electric energy storage technology can enhance the cost-effectiveness of the technology in a supply portfolio. For example, reservoir hydro provides the inherent capacity to forgo generation and store water to generate electricity at a later time and, therefore, has less to gain from linking to a storage technology than other technologies. In the case of intermittent renewables, a linkage to storage improves the cost-effectiveness of the power supply, but the improvement in cost-effectiveness is even greater for the linkage of a high-utilization generating technology with a storage technology.
- **Network integration costs**—the impact of a generating technology addition to the supply portfolio on the generating costs of the rest of the power supply mix.
- **Variable cost per unit of output**—the electric supply costs linked to the level of electric energy output.
- **Fixed cost**—the electric supply costs independent of the level of electric energy output.
- **CO_2 emission footprint**—the level of CO_2 emissions per unit of electric energy output.
- **Other environmental impacts**—the per-unit cost of non–greenhouse gas (GHG) environmental impacts associated with electric generation.

Identifying the cost-effective generation supply portfolio involves long-standing cost-minimization approaches to identify the efficient mix of electric generating technologies and the associated varied utilization rates that are capable of producing electric supply that reliably balances with the varying real-time aggregate demand levels with limited economic inventory options.[12]

A cost-effective mix of fuels and technologies in the electricity supply portfolio reflects the alignment of the cost and performance characteristics of the power system net dependable capacity requirement to the different segments of the aggregate consumer demand pattern. The alignment hinges on how the relative production costs per unit of output for alternative generating technologies change depending on how often and how fast the technology needs to start up and shut down or ramp up and ramp down output. These power supply operating mode attributes determine power supply technology cost-effectiveness because fundamental trade-offs exist in power generating technologies between the up-front capital cost and the operating flexibility and the efficiency of transforming primary energy into electric energy.

Table 2 shows the cost and performance characteristics of two available grid-connected electric generating technologies capable of flexible generation operation, based on the EIA cost and performance profiles found in the Annual Energy Outlook 2016, with heat rates based on actual observed values.

12. Oliver E. Williamson, "Peak-Load Pricing and Optimal Capacity under Indivisibility Constraints," *The American Economic Review* 56, no. 4 (September 1966): 810–27.

As Table 2 shows, the CC technology involves 58% higher up-front capital costs to deliver 35% greater efficiency in transforming natural gas into electricity compared with the CT. Figure 11 shows how the relative costs of these flexible generating resources change at various power plant utilization rates owing to the underlying trade-off between up-front capital costs and generating efficiency. In this example, the natural gas–fired CT and the CC generating technologies are both operationally flexible enough to supply the variable segment of the electric market demand profile; and the cost curves show that average total generation costs (LCOE) decline as utilization rates increase, and the benefits of greater production efficiency do not outweigh the costs until expected utilization rates are above about 30%.

In this example, the CT technology cost-effectively aligns with the segment of aggregate consumer demand that involves the highest incremental levels of aggregate consumer demand that are present less than 30% of the time. The cost curve illustrates the competitive advantage of the CT to supply the infrequent, varying, and higher-than-average levels of electric demand typically experienced around the annual winter and summer maximum aggregate demand periods. This cost-effective alignment of the CT with the peak demand segment of aggregate consumer demand identifies this technology as the least-cost "peaking technology."

Figure 11 also shows that the trade-off between the up-front costs and the greater production efficiency makes the CC generating technology more cost-effective than the CT to supply variable customer loads that are present more than about 30% of the year. Consequently, the CC generation technology cost-effectively aligns with this segment of aggregate consumer demand.

The base-load segment of aggregate consumer demand involves frequent, steady, and lower-than-average levels of aggregate consumer demand. The most cost-effective supply option to serve this base-load segment of aggregate consumer demand involves technologies that do not involve up-front costs to provide a high degree of operating flexibility but rather involve up-front costs to produce higher production efficiency. For example, a biomass cogeneration technology may provide relatively little operating flexibility because the host industrial heat application requires steady utilization to produce a steady supply of steam. In this example, the cogeneration resource can involve higher up-front capital costs compared with either the simple-cycle CT or CC technology while providing relatively higher efficiency in converting fuel into electricity due to the steady cogeneration mode of operation. As a result, an industrial cogeneration application can provide the most cost-effective supply to meet the base-load segment of aggregate consumer demand with a relatively inflexible generating operation profile.

The examples of aligning generation technology cost and performance characteristics to segments of power system consumer demand illustrate that an efficient power system generating supply portfolio will typically incorporate a diverse set of fuels and generating technologies to lower overall production costs compared with a portfolio composed of a single fuel and technology.

Table 2

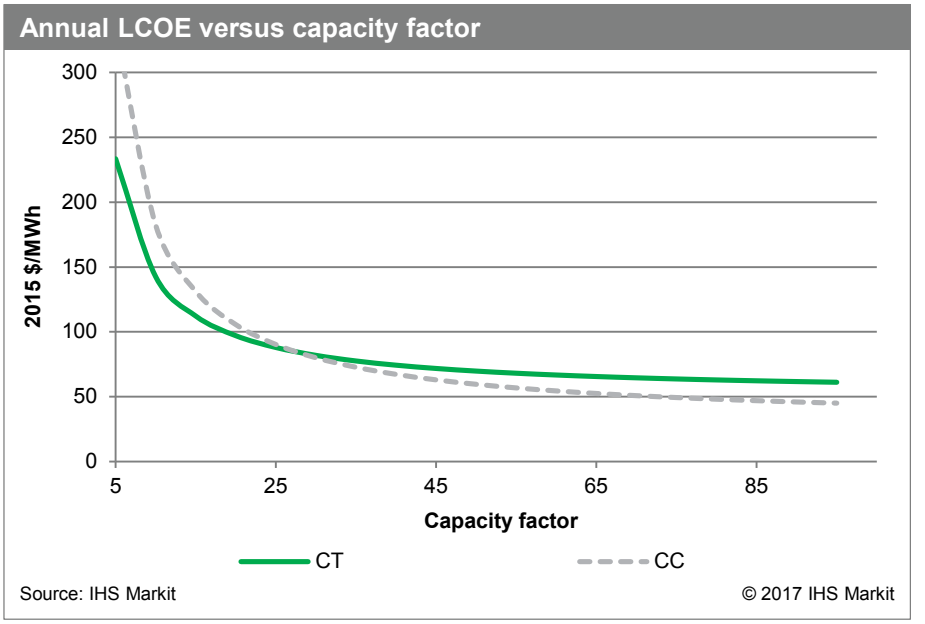
Electric generating technology cost and performance profiles

	Size (MW)	Lifetime/ MACRS (years)	Overnight costs (2015 $/kW)	Lead time (years/CFUDC factor)	Contingency factor	Variable nonfuel O&M (2015 $/MWh)	Fixed O&M (2015 $/MWh)	Heat rate (MMBtu/kWh)
Natural gas–fired CT	237	25/20	632	2/1.14	1.05	10.47	6.65	10,878
Natural gas–fired CC	429	25/20	1,000	3/1.2	1.08	1.96	9.78	7,100

Note: MACRS = Modified Accelerated Cost Recovery System; CFUDC = cost for funds used during construction; O&M = operations and maintenance costs; CT = combustion turbine; CC = combined cycle.
Source: IHS Markit, EIA

The examples showing how cost versus utilization trade-offs dictate cost-effective portfolio shares also illustrate that internalizing all of the costs associated with alternative generating technologies, including any costs of environmental impacts, would alter, but not distort, the determination of the most cost-effective mix of technologies and fuels in an electric supply portfolio.

Figure 11



The cost-effective diversity of dispatchable power supply to match aggregate consumer demand segments creates varied short-run marginal costs (SRMC) of electric production reflecting different technologies and fuels being the marginal sources of generation throughout the year as the power system balances demand and supply in real time. This variation in the SRMC provides the basis to integrate a cost-effective level of intermittent generating technologies and grid-level storage technologies.

The pattern of short-run marginal electric production costs associated with the cost-effective alignment of fuel and technology mix to segments of consumer demand determines the cost-effective entry of intermittent generation technologies, such as wind turbines and solar PV panels. Whenever the sun shines or the wind blows, intermittent electric generating capacity displaces power system generation and the associated SRMC. In addition, intermittent generation can provide some dependable capacity if the intermittent output pattern can be relied on to offset net dependable capacity requirements.

Entry of intermittent resources into a power system supply portfolio creates a net impact on the power system SRMC. On the one hand, intermittent resource entry reduces power system costs when the SRMC of intermittent output is lower than the SRMC of displaced generation. On the other hand, intermittent resource entry increases power system costs when the change in net load (aggregate consumer demand less intermittent output) increases the SRMC of the generation resources operating alongside the intermittent resources to fill in and back up for the intermittent generation. Therefore, integrating intermittent resources into a power supply portfolio is cost-effective when the net present value (NPV) of the intermittent technology entry cost stream is below the NPV of the net reduction in power system costs. Intermittent resource entry integration costs tend to increase with the level of intermittent penetration, and, thus, cost-effective intermittent wind entry ceases when the value of capacity contributions, plus the value of the change in power system SRMC, is no longer large enough to support incremental intermittent power supply entry costs.

The pattern of power system SRMC also determines the economic entry of grid-level electric storage technology, such as pumped storage or battery technologies. A storage technology can charge its storage capacity when the power system SRMC is relatively low and discharge the storage capacity when the SRMC is relatively high. Since the marginal production costs of a cost-effective supply portfolio are

positive and increasing at any point, charging and discharging a storage technology can lower the overall power system cost. Because charging storage capacity occurs during relatively low SRMC levels that correspond to relatively low aggregate consumer demand levels, and discharging storage capacity occurs during relatively high SRMC levels that correspond to relatively high demand levels, the integration of a storage technology can also reduce the need for net dependable capacity. Therefore, integrating storage technology can lower overall power system cost whenever the present value of the storage cost stream is less than the NPV of three power system impacts. The first power system impact is the lower overall power system cost resulting from charging at relatively low power system SRMC and discharging at relatively high power system SRMC. The second is the lower cost of net dependable capacity due to the availability of the discharge capacity during periods of capacity reserve scarcity. The third is the lower average total long-run cost of electric production due to storage entry decreasing the variability of generation patterns and triggering cost-effective realignment of the rest of the generation portfolio. Since economic storage entry reduces power system SRMC differentials with diminishing returns, efficient storage entry into the electricity supply portfolio ceases when the power system cost reductions are no longer large enough to support incremental storage costs.

Understanding the cost-effective level of grid-based electric storage technologies provides a subtle but significant insight. Improvement in the cost and performance of grid-based storage technology leads to more cost-effective storage in the supply portfolio, and as the amount of storage increases, the net-load factor increases along with the base net load. As a result, the cost-effective share of the efficient high-utilization power generating technologies in the cost-effective power supply portfolio increases. For example, a breakthrough in storage cost and performance would improve the cost-effectiveness of a high-utilization biomass generating technology or combined heat and power (CHP) technology in a supply portfolio more than the storage breakthrough would improve the cost-effectiveness of a low-utilization intermittent generating resource in the supply portfolio (see Appendix II: Electricity storage paradox).

Understanding the composition of a reliable, resilient, and efficient electric supply portfolio provides six key insights:

- **Efficiency requires integrating a diverse fuel and technology supply mix.** A cost-effective electric generating supply portfolio integrates available technologies to achieve the lowest overall cost to generate electricity aligned with the segments of aggregate consumer demand defined by the recurring time pattern of electricity usage throughout the year.

- **A reliable, resilient, and efficient supply portfolio requires diverse power supply rather than maximum diversity.** A cost-effective power supply portfolio will typically include some, but not necessarily all, of the available electric generating technologies. Diversity is necessary for reliability, resilience, and efficiency, but a reliable, resilient, and efficient portfolio does not maximize supply diversity by incorporating as many technologies as possible in equal generation shares.

- **System efficiency trumps individual plant efficiency.** Integrated power supply optimization differs from individual generating resource optimization. An efficient outcome does not necessarily involve all resources operating at their most efficient stand-alone utilization rates to achieve the minimum possible individual plant LCOE production. Power system utilization of generating technologies below their stand-alone maximum efficiency rate is not a source of economic inefficiency, because the efficiency objective is at the power system level rather than the individual plant level.

- **A cost-effective mix of generating resources does not need the same level of operating flexibility.** Greater operational flexibility is not always cost-effective, because the majority of aggregate power system net load involves a steady, constant base net load.

- **Incorporating grid-based electricity storage likely increases base net-load requirements.** Optimizing economic storage in power supply favors meeting the ups and downs in demand from inventory and producing output from high-utilization production technologies. As a result, more grid-based storage will not necessarily improve the cost and performance of low-utilization, intermittent resources relative to the high-utilization, base-load resources.
- **Environmental policy initiatives can harmonize with market operations.** Formulating policy approaches to appropriately balance benefits and costs can alter, but not distort, the operation of a well-structured wholesale electricity market.

Government regulation harmonized with well-structured electricity markets can produce reliable, resilient, and efficient electricity sector outcomes

A well-functioning electricity market involves a coordinated mix of competitive forces and regulatory processes. Often, the harmonization of government involvement in the marketplace is taken for granted and leads some industry observers to fear that any government intervention in the electricity marketplace will inhibit well-functioning markets. But markets cannot function well without appropriate government involvement. For example, the government provides the court systems that make electricity market transactions enforceable, and government regulations set the financial disclosure requirements and the accounting standards that enable efficient capital markets to allocate capital to electric infrastructure investments. However, not all government interventions are appropriate. Often, concerns regarding government market interventions reflect the fear that regulators are being unduly influenced to protect some market participants from the "creative destruction" of the marketplace.[13] The implication is that government interventions into the marketplace need to be evaluated against well-defined principles.

Alfred Kahn wrote the textbook on government regulation and outlined the principles of appropriate government regulation:

> **The market model benchmark:**
>
> > The main body of microeconomic theory that can be interpreted as describing how, under proper conditions, an unregulated market economy will produce optimum economic results.
>
> **The economic rationale for regulation:**
>
> > That for one or another of many possible reasons, competition simply does not work well.
>
> **The principle of regulation:**
>
> > The single most widely accepted rule for the governance of the regulated industries is regulate them in such a way as to produce the same results as would be produced by effective competition, if it were feasible.[14]

Principled government interventions harmonize with markets to produce the outcomes of effective competition. Therefore, harmonizing regulation with a well-structured wholesale electricity marketplace

13. Joseph Schumpeter, *Capitalism, Socialism and Democracy*, Harper, New York, 1975 (original publication 1942), p. 83.

14. Alfred Kahn, *The Economics of Regulation: Principles and Institutions*, vol. 1, MIT Press, Cambridge, Massachusetts, 1988 (original publication 1970), p. 11 and 17.

can produce timely price signals that shape reliable, resilient, and cost-effective generating technology investment decisions involving the trade-offs between the up-front capital costs and the reliability, resilience, and efficiency of transforming primary energy into electric energy.

A well-structured wholesale electricity market has a sufficient number of rival generators competing to serve the segment of consumer demand that occurs infrequently when overall demand is around maximum levels. Competitive forces drive investment toward generating technologies with flexible dispatch capabilities and the lowest average total costs at low annual utilization rates. However, during the infrequent, highest hourly market demand periods, competitive forces drive the market-clearing energy price to reflect the SRMC of rival peaking resources, and an inherent flaw exists in electricity markets that prevent the SRMC of the peaker units from rising to equal the long-run marginal costs (LRMCs) when the market is in long-run balance, including the desired reserve margin associated with reliability goals. As a result, principled government interventions to address this problem evolved to support capacity markets or ORDCs. These regulatory interventions offset this inherent market flaw by generating capacity market prices or ORDC payments that produce an efficient market outcome in which a market-clearing capacity price or operating reserve demand payment closes the gap between the SRMC and LRMC of the cost-effective peaking technology when the market is in long-run balance with the desired level of reserves. Further, these market prices provide an efficient signal for resiliency investments. For example, energy and capacity prices determine the expected cost to a generator from fuel supply disruption. If the expected cost for a CT exceeds the cost of incorporating backup fuel capability, then the marketplace will generate investments in fuel supply resiliency for these peaking generating technologies.

Although a well-structured electricity market outcome can generate adequate cash flows to support the cost-effective and resilient peaking technologies in the long run, we do not expect an efficient market outcome to involve only investments in CTs. When a sufficient number of rival suppliers compete to serve the segments of the electric market demand profile that occur over periods of increasing duration, the competitive advantage no longer falls to the most cost-effective resilient peaking technologies but instead falls to flexible generating technologies with higher up-front capital costs and greater production efficiency compared with the least-cost peaking technology. In an efficient market outcome, competitive forces drive rival generators to invest in generation technologies with up-front investment costs that are higher than for peakers in order to deliver greater production efficiency. This additional up-front investment is covered by cash flows generated when the peaking technologies' SRMCs are setting the market-clearing price and these more-efficient generating technologies are operating with lower SRMCs (this difference between market-clearing prices and the SRMC is what economists call "inframarginal rents"). Again, price signals provide incentives for resiliency. For example, a CC generator lacking a firm fuel supply contract could face an episodic fuel supply disruption and the associated expected loss of inframarginal rents in the energy market along with the loss of capacity payments in the capacity market. If the NPV of these losses is greater than the NPV of the premium associated with firm contractual fuel supply, then market prices provide the incentive to invest in this power supply resiliency.

Although an efficient long-run electricity market outcome can generate adequate cash flows to support the cost-effective and resilient peaking technologies along with cost-effective and resilient higher-utilization load-following technologies, we do not expect an efficient market outcome to involve only investments in flexible generating technologies with varying utilization rates and productive efficiencies. Some segments of consumer demand do not fluctuate through time. When a sufficient number of rival generators compete to supply this stable, base-load segment of the market demand profile, the competitive advantage falls to less dispatch-flexible technologies capable of trading off more up-front capital costs for greater generating efficiency. For example, a CHP technology deployed in an industrial cogeneration application involving the joint production of a steady flow of steam for an industrial process

and the associated steady stream of electrical output can rely on inframarginal rents available when the higher SRMC-based bids of the flexible, lower up-front cost generating technologies are setting prices that generate the energy market cash flows that cover the cost-effective investments in the higher up-front capital cost technologies capable of greater production efficiency at high utilization rates. Again, market prices signal cost-effective investment in resiliency. For example, a high-utilization coal-fired power plant faces periodic episodes of fuel delivery interruptions owing to the potential for rivers to freeze and inhibit barge traffic. In this case, the energy market price indicates the potential loss of inframarginal rents, and the capacity market price indicates the potential loss of capacity revenues from fuel supply disruptions. Balancing these expected costs against the cost of holding fuel in inventory provides the basis to determine efficient resiliency from stockpiling fuel.

A well-functioning electricity market produces a temporal pattern of electricity market price signals that coordinate the disaggregated investment decisions in the marketplace to produce a reliable, resilient, and efficient supply portfolio that also provides price signals for the cost-effective entry of intermittent renewable electric generating technologies. For example, unsubsidized wind resource investment is economic when the NPV of the wind entry cost stream through time is below the NPV of the market price–based revenue stream available from selling wind output along with any capacity revenue contributions. Since wind output tends to occur disproportionately in hours with relatively lower demand, the capacity contribution is typically small and the displaced generation SRMC is below average. Nevertheless, wind entry displaces dispatchable generation capacity and energy and thereby can reduce the SRMC of power system supply. Economic wind entry ceases when the value of the capacity and the displaced energy is no longer large enough to support incremental investment.

Storage technologies can alter electric market demand and supply interactions to increase economic efficiency. A storage investment is economic when the present value of the battery cost stream is less than the NPV of cash flow produced by buying electricity to charge the battery when prices are low and selling electricity by discharging the battery when prices are high, along with any payments for capacity or ancillary service contributions.

The impact of storage entry on the marketplace involves increasing market demand (shifting the market demand curve to the right) when charging during hours of relatively low market-clearing prices and, conversely, decreasing market demand (shifting the market demand curve to the left) when discharging during hours of relatively high market-clearing prices. Since relatively low prices correspond to relatively low demand and, conversely, relatively high prices correspond to relatively high demand, the market impact of economic storage entry produces a higher net-load factor and triggers adjustments in the dispatchable generation portfolio that produce a lower average total cost of electric production. In doing so, storage entry reduces market price variability through time, and economic entry ceases when the price differences are no longer large enough to support incremental investment.

The bottom line is that a well-structured electricity market incorporating principled government regulations can generate competitive forces that produce an annual pattern of market-clearing price signals that cover the LRMC of a reliable, resilient, and efficient electric supply portfolio. As a result, the level and variation in market-clearing prices drive investment to a mix of storage and generating technologies with different costs, efficiencies, and operating characteristics that together produce the lowest possible total average cost to meet the peak demand and the annual aggregate net-load pattern

Wholesale electricity market distortions from policy and market disharmony

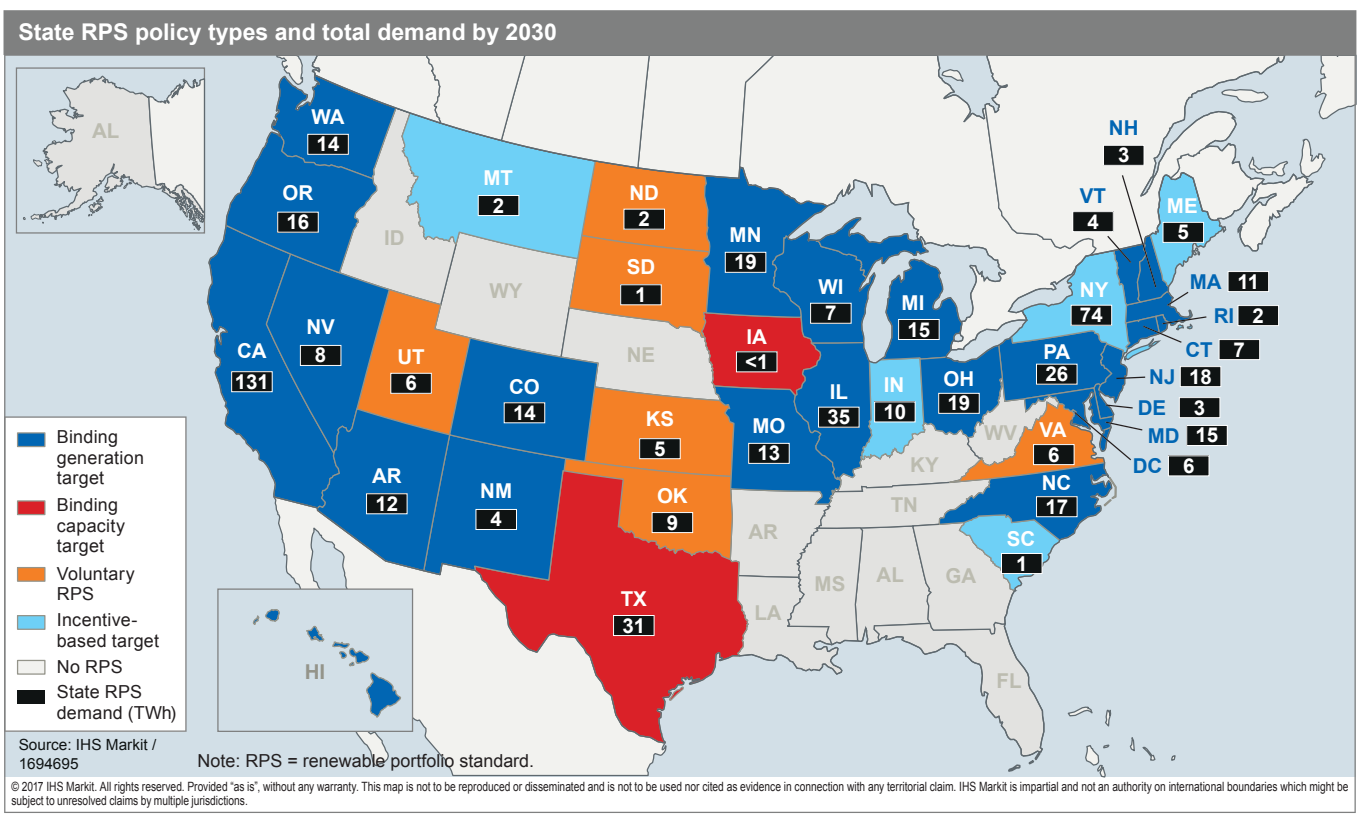
The political process generates electric sector policy at the federal, state, and market level, and the potential exists for this process to produce market interventions that are at odds with the principles of

regulation. This lack of harmonization with regulatory principles distorts market outcomes and makes the US electric supply portfolio less reliable, resilient, and cost-effective, thereby reducing the consumer net benefit from electricity consumption. An understanding of market distortions involves contrasting distorted market outcomes to the characteristics expected in a well-functioning wholesale marketplace.

A well-functioning wholesale marketplace provides price signals that coordinate disaggregate investment decisions to produce a reliable, resilient, and efficient power supply portfolio. Some policies, including the federal Production Tax Credit (PTC) and Investment Tax Credit, state net metering programs crediting solar PV at retail rather than wholesale prices, and state renewable generation portfolio share mandates, distort market price signals and create intermittent renewable generation shares above the level associated with a reliable, resilient, and efficient power supply portfolio. Under these conditions, wholesale electricity market distortions involve market-clearing price suppression. Figure 12 shows the current level and extent of state mandates for renewable resources. From this technology-driven perspective, the power system objective shifts away from reliably providing consumers with the electricity that they want, whenever they want it, and with efficient resilient supply and toward an objective to minimize the additional costs imposed on the power system from mandates of wind and solar generation shares in excess of the cost-effective share in the supply portfolio.

Existing federal subsidy policies shift some costs from power bills to tax expenditures. For example, the federal PTC shifts as much as 50% of wind power supply costs from power bills to current or future tax expenditures. The pretax value of the PTC subsidy made tax equity a primary funding vehicle for wind projects. Although a phaseout of the PTC is scheduled for 2019, the PTC is grandfathered for the first 10 years of project operating life, and thus it will affect market price formation for more than a decade to come. As a result, the volume-based subsidy creates a short-run marginal generating opportunity cost of –$23/MWh (2016) for subsidized wind generation if output is restricted because of a lack of consumer demand.

Figure 12



The lack of harmonization between federal and state policy initiatives and market operation causes four significant wholesale electricity market distortions:

- **Price suppression.** Whenever policy initiatives drive the addition of zero-SRMC resources beyond their cost-effective level, the power system net-load demand curve shifts leftward when the wind blows or the sun shines and lowers the market-clearing wholesale energy price, all else equal, compared with the undistorted wholesale electricity market outcome.
- **Delayed market adjustments.** Whenever policy initiatives drive the addition of zero-SRMC resources that provide some net dependable capacity toward meeting the peak load plus the reliability reserve requirement, the capacity market price or the ORDC scarcity-based energy prices are lowered from the level conditions would otherwise produce in an undistorted wholesale electricity marketplace.
- **Integration costs.** Policy initiatives that drive more intermittent generation than is cost-effective typically involve intermittent generation variability that is not highly correlated with aggregate consumer consumption temporal patterns and causes the power system net-load factor to decline. This integration of intermittent resource output causes the unit cost of the remaining dispatchable power supply to increase compared with the outcome in an undistorted wholesale marketplace.
- **Risk exposure.** Whenever policy initiatives drive intermittent generation shares and natural gas–fired generation shares to exceed the level associated with a reliable, resilient, and efficient supply portfolio, the exposure to risk factors capable of generating potential significant excursions from normal operating conditions increases compared with the undistorted wholesale market outcome. This elevates the cost of adjustments to the economic dispatch to satisfy security of supply constraints and ensure resiliency to the wider scope of potential disruptions. This market distortion aggravates an existing market flaw in some existing wholesale markets in which price formation rules do not fully compensate resources for the full marginal power system cost of providing security and resiliency.

Appendix III provides recent examples of these policy-driven market distortions in the ERCOT, PJM, and California electricity marketplaces.

US power supply portfolio retirements and replacements

Electric wholesale market price signals determine the level and pace of power plant retirement and replacement. A well-functioning electricity market balances demand and supply in the long run and produces a level and variation in wholesale electricity prices that covers the LRMCs of the diverse generating technologies and fuel sources that make up the reliable, resilient, and efficient supply portfolio aligned with the segments of aggregate consumer demand and the risk factors of the electric supply environment.

Economic power plant retirements occur in a well-functioning marketplace because market-clearing prices reflect the LRMC of replacement power resources and thus provide a signal for the cost-effective timing to replace existing generation. An existing resource is economic to operate as long as its going-forward costs are covered by market cash flows reflecting the cost of replacement. When market cash flows do not cover the going-forward costs of existing generation but do cover the costs of new supply, then it is economic to retire and replace the existing resource.

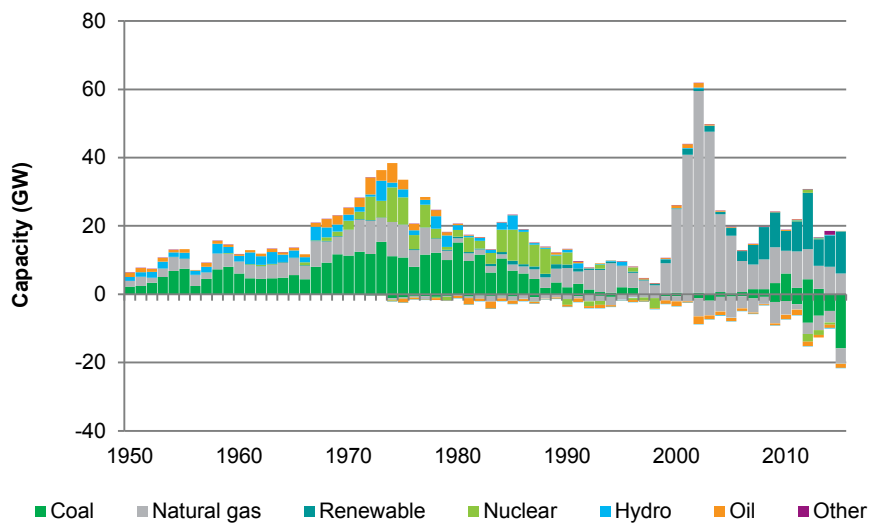
Figure 13 shows the historical retirement and replacement patterns of US power plants in the power supply portfolio. Some of these retirements and replacements are economic and some are uneconomic. Separating the two types of power supply turnovers involves a comparison of the going-forward costs with the costs of replacement. An uneconomic power plant retirement occurs when a power plant closes and is replaced even

though it would have been lower cost to keep it operating. Conversely, an economic power plant retirement occurs when a power plant closes and is replaced by a plant with a lower cost than required for continued operation.

Often, uneconomic power plant retirements are confused with economic power plant retirements. For example, some industry observers conclude that low natural gas prices have made nuclear power plants uncompetitive with natural gas–fired generators. If this were the case, then the market outcome would involve profitable natural gas–fired generators displacing unprofitable nuclear power plants. However, the market results do not show such outcomes. Wholesale electricity market cash flows to the natural gas–fired generators listed in Table 3 do not produce market valuations indicating that these competitors are winning in the marketplace by cost-effectively replacing obsolete generating resources (see Figure 14).

Figure 13

US generating capacity additions and retirements, 1950–2015



Source: IHS Markit, ABB Velocity Suite

Table 3

IHS Markit US power business strategy group companies

Utility	Delivery	Competitive
AEP Energy, Inc.	CenterPoint Energy	Calpine
ALLETE, Inc.	Fortis Inc.	Dynegy Inc.
Alliant Energy Corp.	Con Edison	NRG Energy, Inc.
Avista Corporation	ITC Holdings Corp.	
Cleco	NiSource Inc.	
CMS Energy Corporation	Eversource	
El Paso Electric	Pepco	
Empire District	Pacific Gas and Electric Company	
Great Plains Energy Incorporated	UIL Energy	
IDACORP, Inc.		
Pinnacle West Capital Corporation		
PNM Resources, Inc.		
Portland General Electric		
SCANA Corporation		
Southern Company		
TECO Energy		
UNS Energy Corporation		
Westar Energy		
Xcel Energy Inc.		

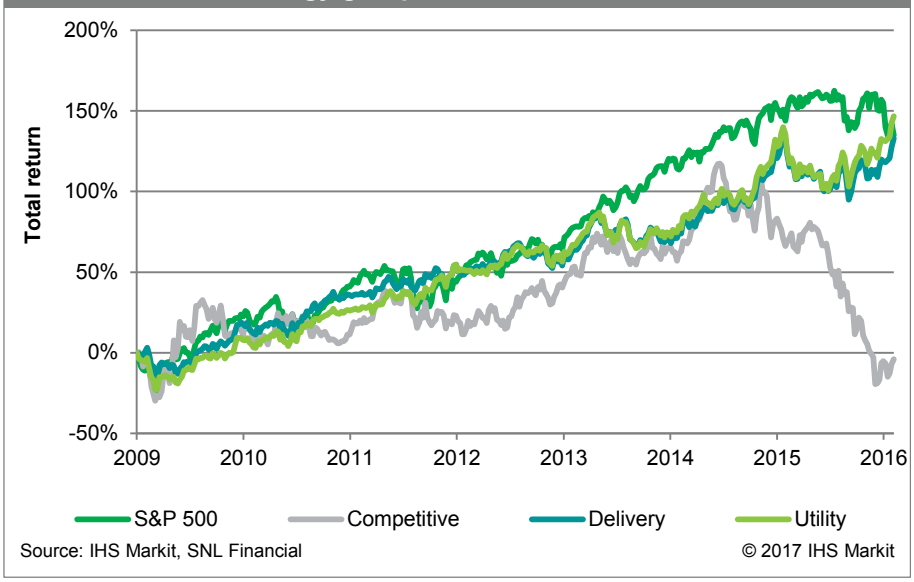
Source: IHS Markit

Relative financial performance of select utility business models

Price suppression from mandates of subsidized renewable resources causes underinvestment in power supply reliability and resiliency attributes and discriminates compensation for CO_2 emission attributes. These market distortions, along with market flaws involving undercompensation for security-constrained price formation, suppress the price signal governing power plant retirement and replacement.

Prices suppressed below the LRMC of replacement supply cause premature retirements of power plants. A premature retirement occurs when a power plant closes with a lower cost to continue to operate than the cost of its replacement. Since price suppression impacts on generator cash flows are skewed toward the off-peak segment of consumer demand, the problem of uneconomic retirements disproportionally affects the high-utilization power plants aligned to cost-effectively supply the base-load segment of aggregate consumer demand. In addition, CO_2 emissions can increase when the premature closure involves a zero–CO_2-emitting nuclear power plant and the replacement power resources are intermittent renewables integrated by natural gas–fired technologies with relatively higher combined CO_2 emissions per kilowatt-hour. Figure 15 shows the recent announcements of nuclear power closures.

Figure 14



New England provides an example of this CO_2 emission boomerang due to renewable mandates suppressing cash flows and causing the uneconomic closure of nuclear capacity. The Vermont Yankee Nuclear Power Corp. nuclear power plant was closed even though the going-forward costs of operation were less than the cost of replacement, based on the cost profiles of the electric supply pipeline of mandated subsidized renewable generation and natural gas–fired CC plants that made up the replacement power sources. This premature nuclear power plant closure caused ISO New England electricity market CO_2 emissions to increase by 7% from 2014 to 2015. In another few years, the premature closure of the Pilgrim Nuclear Power Station will have a similar impact on the regional electricity sector CO_2 emission level.

Power supply replacement costs

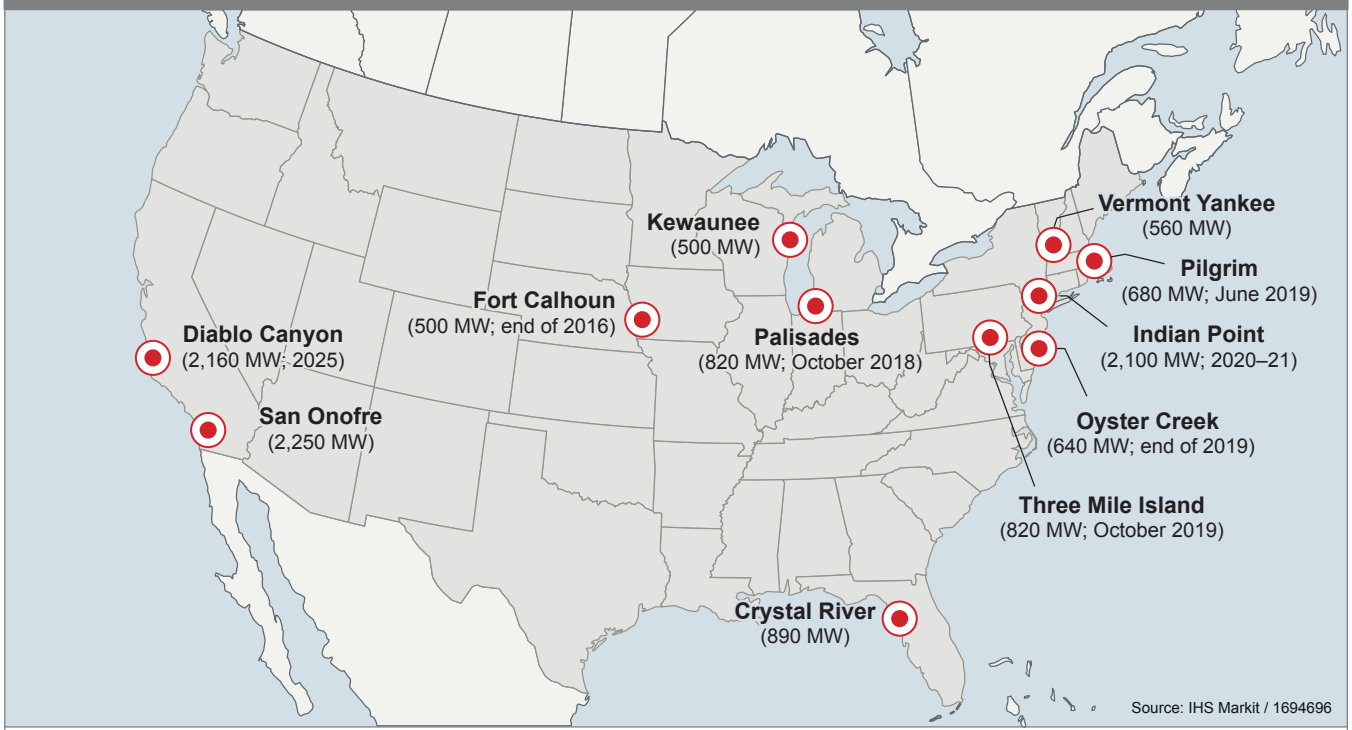
Quantifying the cost of replacing the uneconomic retirement of power plants aligned to the nonpeaking segments of aggregate consumer demand involves developing cost estimates of the annual levelized cost basis to provide equivalent capacity and energy outputs. Replacement can involve a single technology or combination of technologies. The cost and performance characteristics of available grid-connected electric generating technologies are based on the EIA profiles in the Annual Energy Outlook 2016 along with heat rates reflecting actual operating results (see Table 4). The size of each generating option reflects the current minimum efficient scale of each technology.

The project operating lifetime is the basis for the calculation of straight line depreciation to account for the consumption of capital in the production process over the life of the asset. The modified accelerated cost recovery schedule is the recovery period for accelerated depreciation used when calculating taxes.

Overnight costs are the total of all cost components for the project based on prices in a single year. The transmission investment adder reflects the incremental grid investment associated with the project

Figure 15

Nuclear plant proposed and completed closures since 2012



interconnection to the network.[15] Renewable transmission cost adders are higher than thermal power plant transmission cost adders for two reasons. First, wind and solar resources are typically farther away from consumer loads than thermal generation technologies and therefore require longer radial spur transmission connection to the grid. Second, renewable resources are smaller and more geographically dispersed and, thus, require more granular linkages to more sites. For example, in Texas the expansion of wind energy required about $6 billion of transmission investment to link the Competitive Renewable Energy Zones (CREZs) to load centers. The transmission cost adder in ERCOT was $600/kW of installed wind capacity. An estimate of the incremental transmission investment needed to upgrade the current system capabilities as well as build

Table 4

Electric generating technologies cost and performance characteristics

	Size (MW)	Lifetime/ MACRS (years)	Overnight costs/included transmission cost adder (2015 $/kW)	Lead time (years/ CFUDC)	Contingency factor	Variable nonfuel O&M (2015 $/MWh)	Fixed O&M (2015 $/kW-year)	Heat rate (MMBtu/kWh)
Wind	100	20/5	1,536/500	3/1.2	1.07	0	45.98	
Solar PV	150	20/5	2,362/500	2/1.14	1.05	0	21.33	
Natural gas–fired CT	237	25/20	632	2/1.14	1.05	10.47	6.65	10,878
Natural gas–fired CC	429	25/20	1,000	3/1.2	1.08	1.96	9.78	7,100

Source: IHS Markit, EIA

15. Estimates of typical incremental transmission investments are based on Andrew Mills, Ryan Wiser, and Kevin Porter, *The Cost of Transmission for Wind Energy: A Review of Transmission Planning Studies*, Ernest Orlando Lawrence Berkeley National Laboratory, 2009, retrieved 24 August 2017; and National Academies of Sciences, Engineering, and Medicine, *The Power of Change: Innovation for Development and Deployment of Increasingly Clean Electric Power Technologies*, The National Academies Press, Washington, DC, 2016.

new transmission to implement the estimated 15,200 MW of new renewable resources required to meet California's 50% renewables goal is $5.8 billion—implying a $382/kW incremental transmission cost adder.[16]

The lead time is the number of years required for project construction. The cost of funds used during construction factor reflects the capitalization of the cost of debt and equity funds tied up during construction.

The contingency factor reflects the specific provisions for unforeseen elements of costs within a defined project scope as defined by the American Association of Cost Engineers based on previous experience indicating that unforeseeable cost elements are likely to add to the total costs.

Variable O&M exclude fuel costs. Fixed O&M are annual costs that are expensed rather than capitalized and more a function of time than of plant annual utilization rates.

The heat rate (British thermal units of fuel input per kilowatt-hour of generation output) measures the efficiency of transforming fuel into electricity. The prices of fuel inputs for power generation typically reflect the cost of the total British thermal units content of the fuel expressed on a dollar per million British thermal units basis. In the thermal generation process, some of the British thermal units content of the fuel input vaporizes the moisture present in the combustion process, and this heat is not converted into electricity. As a result, equipment manufacturers' thermal power plant performance specifications typically express heat rates on the basis of a fuel input with a lower heating value accounting for only the British thermal units that were converted into electric energy. The higher heating value aligns with the input fuel price and includes the use of heat to vaporize moisture as well as to generate electricity. In the case of the natural gas–fired generating technology, the higher heating value is about 11% greater than the lower heating value. The difference between higher and lower heating values explains the 11% difference between the actual average heat rates of new natural gas–fired CC generating technologies shown in Table 5 and the heat rate specification appearing in the EIA cost and performance characteristics of new central station natural gas–fired generating technologies.

The variation of heat rates around the capacity-weighted average shown in Table 5 reflects differences in operating conditions across new natural gas–fired CC power plants. In particular, altitude, humidity, and ambient air temperature all affect the heat rates of natural gas–fired generating technologies. The equipment manufacturers' generating technology specifications typically reflect an operating altitude of sea level with static standard conditions of ambient air temperature equal to 59 degrees Fahrenheit with 60% relative humidity, and actual heat rates reflect site-specific altitude and dynamic temperatures and humidity across hours of operation.

EIA reports that the average realized natural gas–fired power plant heat rate in 2016 was 7,878 Btu/kWh. This replacement cost analysis utilizes a heat rate performance parameter closer to the observed values of the new power plants shown in Table 5.

Common cost parameters for power plant development are shown in Table 6.

The fuel input costs for replacement natural gas–fired generating technologies reflect the recent US average delivered cost of natural gas for the electric power industry (see Table 7).

16. Renewable Energy Transmission Initiative 2.0—*Transmission Technical Input Group, Transmission Capability and Requirements Report*, 24 October 2016, retrieved 24 August 2017; and Edison Electric Institute, *Transmission Projects: At A Glance*, December 2016, p. vii, retrieved 24 August 2017.

Table 5

New central station natural gas–fired generating technologies cost and performance characteristics

	Plant type	State	Online year	Nameplate (MW)	Generation (MWh)	Capacity factor	Fuel consumption (MMBtu)	Heat rate (Btu/kWh)
Cherokee	CC	Colorado	2015	626	2,719,773	49%	19,724,297	7,252
Cane Run	CC	Kentucky	2015	807	4,882,086	69%	32,874,527	6,734
Nelson Energy Center	CC	Illinois	2015	571	1,053,862	19%	7,761,892	7,365
Garrison EnergyCenter	CC	Delaware	2015	361	1,540,533	49%	10,762,503	6,986
Woodbridge Energy Center	CC	New Jersey	2015	720	4,751,779	68%	32,571,277	6,855
Panda Temple I Power Project	CC	Texas	2015	1,468	4,336,063	31%	31,325,080	7,224
Newark Energy Center	CC	New Jersey	2015	685	4,330,434	67%	29,489,358	6,810
Port Everglades	CC	Florida	2016	1,260	5,997,574	67%	41,166,027	6,864
Brunswick County Power Station	CC	Virginia	2016	1,371	5,895,472	61%	43,269,513	7,339
Panda Patriot Power Project	CC	Pennsylvania	2016	765	2,942,537	77%	19,841,480	6,743
Panda Liberty Power Project	CC	Pennsylvania	2016	756	2,444,556	64%	16,349,118	6,688
Carty Generating Station	CC	Oregon	2016	413	1,362,782	62%	9,566,449	7,020
Capacity-weighted average						**57%**		**7,010**

Source: IHS Markit, EIA

Existing generating resource going-forward costs

Analyses of Form 1 data submitted to the US Federal Energy Regulatory Commission (FERC) and EIA schedule 860 data submitted to the EIA provide the estimates of the going-forward costs of existing resources in the US power supply portfolio (see Table 8).[17]

Table 9 shows US nuclear power plant going-forward cost assessments from the NEI differentiated by single-plant and multiplant sites.[18]

The cost of uneconomic power plant retirements

Average going-forward costs for US technologies currently operating to serve the non–peak-load segments

Table 6

Common cost parameters for power plant development

Assumption	Value
After-tax cost of equity	12%
Pretax cost of debt	8%
Inflation rate	2%
Capital structure debt-to-equity ratio	60%/40%
Federal tax rate	35%
State tax rate	9%
Property and insurance rate	1.60%

Source: IHS Markit, EIA

Table 7

US average delivered cost of natural gas for the electric power industry

Year	Trillion Btu	$/MMBtu
2013	8,721	4.3
2014	8,679	5.0
2015	10,174	3.2
2016	9,980	3.2
Weighted average, 2013–16		3.9

Source: IHS Markit, EIA

Table 8

Levelized going-forward costs of existing US power supply portfolio resources, 2015 ($/MWh)

Technology	Variable	Fixed	Total
Conventional coal fired	31.1	9.1	40.2
Conventional gas-fired CC	36.3	14.8	51.2
Hydro			35.8

Source: IHS Markit, EIA, FERC

17. Thomas F. Stacy and George S. Taylor, *The Levelized Cost of Electricity from Existing Generation Resources*, Institute for Energy Research, June 2015, retrieved 24 August 2017.

18. NEI, *Nuclear Energy 2016: Status and Outlook, Annual Briefing for the Financial Community*, 11 February 2016, retrieved 24 August 2017.

of consumer demand are significantly below replacement costs. Figure 16 shows the differences between average going-forward costs for electric supply resources supplying the nonpeaking segments of aggregate consumer demand and the cost of replacement from natural gas–fired CC and a mix of intermittent wind and solar resources integrated by natural gas–fired CC power plants in proportions reflecting the current pipeline of capacity additions shown in Figure 3.

Analyses of the changes in going-forward costs for both coal and nuclear plants show that these costs increase by less than 1% per year over the observed age distribution of existing plants. Therefore, the existing cost gaps between the going-forward costs of existing resources and the replacement costs indicate that the typical existing power plant will likely not be economic to retire and replace for another decade or more.

Table 9

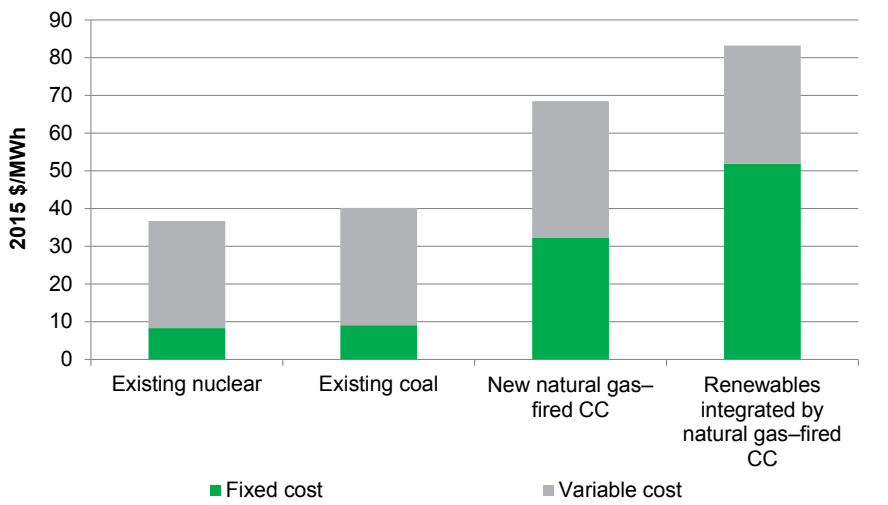
Levelized going-forward costs of existing US power supply portfolio resources, 2015 ($/MWh)

Plant type	Levelized cost
Single-unit nuclear plant	44.6
Multiunit nuclear plant	34.1
Average nuclear plant	36.7

Source: IHS Markit, Nuclear Energy Institute (NEI) © 2017 IHS Markit

Figure 16

US average levelized annual cost of non–peak-load energy



Source: IHS Markit, EIA, FERC, NEI © 2017 IHS Markit

The less efficient and resilient US electric supply diversity case: 2014–16

Subsidies for renewables, state renewable generation share mandates beyond cost-effective levels, and unresolved security-constrained dispatch price formation shortcomings suppress the level and distort the variation of wholesale electricity prices. These market flaws and distortions cause uneconomic retirement and replacement of existing electric generating resources. As a result, the turnover of the US electric supply portfolio accelerates and moves toward a less cost-effective mix of technologies and fuel sources in the US power supply portfolio that involves too many peaking technologies and not enough base-load technologies.

The current accelerated turnover of generating resources in the US power supply portfolio is eroding the net benefit to US consumers from electricity consumption. The potential exists for current trends to lead to a less diverse supply portfolio made up of no nuclear, coal, or oil generating resources and 20% less hydro capacity, with the rest of generation made up of wind and solar resources integrated with natural gas–fired generating technologies in proportions reflecting the current mix of these technologies and fuel sources in the new power supply pipeline.

Comparing the actual cost of electricity production from the US power supply portfolio with an estimate of electric production costs from the less efficient diverse portfolio mix in recent years provides an estimate of the potential cost of doing nothing to address the current wholesale power market distortions and flaws.

Backcasting demand and supply interactions at a monthly frequency for 2014 to 2016 within the three US interconnections in the Lower 48 with a less efficient diverse power supply portfolio produced estimates of the impact on the consumer direct cost of electricity purchases, the average retail power price, and the consumer net benefits from electricity consumption. The backcasting allows estimation of the change in the regional variable cost of electric production (dollars per megawatt-hour). This variable cost is added to the higher nonvariable costs (on a levelized per–megawatt-hour basis) associated with replacement of existing resources with the mix of resources—including additional transmission investment requirements—found in the current new capacity pipeline to estimate the total cost impact.

Less efficient diversity case electric production cost and retail electricity price impacts

Table 10 compares and contrasts the outcomes of the existing US portfolio and the less efficient diverse US power portfolio case. All costs were calculated on an unsubsidized basis.

The microeconomic impact of the less diverse case involves an average annual increase of $114 billion in the direct cost of electricity to consumers when conditions reflect the actual conditions over 2013–16. This impact is similar to the results of the previous IHS Markit study that found an average annual impact of about $93 billion when conditions reflected the actual conditions over 2010–12. In this updated study, the condition of holding all else constant is relaxed by allowing for a consumer reaction to reduce electricity in the face of the price increases. Although this response to lower electricity purchases reduces the increase in the direct cost of electricity to consumers, accounting for the loss in net benefits from the forgone electricity consumption results in a consumer impact that averages about $98 billion in the less diverse case compared with the existing diverse US electric supply outcomes (see Table 11).

The bottom line is that US consumers face an average annual loss in net benefits from electricity consumption of about $98 billion when they adjust to the higher retail electricity price with all else constant.

Table 10

Current US power supply portfolio versus less diverse case

	Impact	Eastern	ERCOT	Western	US Lower 48
2016	Total electric production cost change (billions of 2015 dollars)	80.3	6.5	18.7	105.5
	Percent change in real average retail price	28.0	22.9	23.5	26.8
2015	Total electric production cost change (billions of 2015 dollars)	82.0	6.4	19.0	107.4
	Percent change in real average retail price	28.0	21.3	23.1	26.5
2014	Total electric production cost change (billions of 2015 dollars)	100.7	7.7	19.9	128.3
	Percent change in real average retail price	33.8	25.4	24.2	31.3
2013	Total electric production cost change (billions of 2015 dollars)	92.3	3.4	19.7	115.4
	Percent change in real average retail price	31.6	11.8	24.4	28.7
US average, 2013–16	Total electric production cost change (billions of 2015 dollars)				114.2
	Percent change in real average retail price				28.3
	Percent change in monthly power bill variance	86.0	47.0	13.0	22.0

Source: IHS Markit

Table 11

US consumer net benefits, current versus higher prices, 2014–16 (billions of dollars, nominal)

	Total retail electricity supply cost			Total consumer net benefit		
Year	Current price	Higher price	Difference	Current price	Higher price	Difference
2016	$381	$397	$15	$442	$350	($92)
2015	$391	$406	$14	$451	$357	($94)
2014	$393	$410	$17	$450	$341	($109)

Source: IHS Markit © 2017 IHS Markit

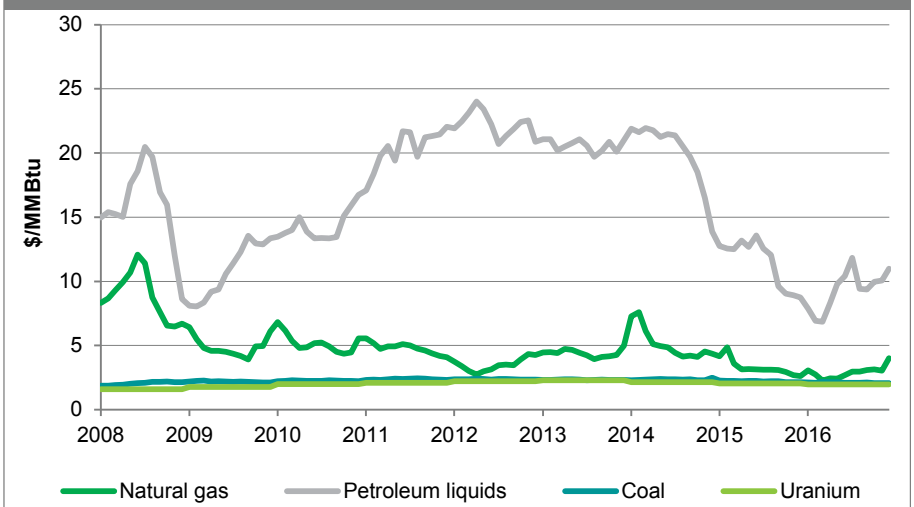
Variation in monthly consumer electricity bills

The greater delivered price variability of natural gas relative to other fuels used in power generation causes the monthly variation in retail electricity bills to increase by 22% in the less diverse US power portfolio case compared with actual monthly power bill variation.

In our 2014 assessment, *The Value of US Power Supply Diversity*, we examined the factors present in the shale gas era that drove the multiyear cycles in natural gas prices. Besides the cyclical drivers of demand and supply situational uncertainty and recognition and adjustment lags, the previous report also focused on the risk factors that cause price spikes and natural gas deliverability constraints. The cyclical drivers and risk factors remain visible in the natural gas sector. Natural gas prices continue to display more variation than other delivered fuel prices to the electric sector (see Figure 17).

Figure 17

Average delivered fuel cost for electricity generation (per MMBtu), 2008–16



Source: NEI, EIA © 2017 IHS Markit

The polar vortex; the leak at the Aliso Canyon natural gas storage facility; and the growing antifossil, "leave it in the ground" movement opposing the construction of natural gas pipeline and storage infrastructure indicate that natural gas infrastructure is unlikely to develop in-sync with electric generation fuel requirements. The shifting relationships between demand and supply will continue to make prices difficult to anticipate, prone to multiyear cycles, and subject to periodic price spikes and deliverability constraints.

Incorporating power supply resiliency to known risk factors capable of triggering excursions from normal operating conditions is fundamental to power system strategic planning and reliability standards for power system operations. Contingency planning is central to North American Electric Reliability Corporation standards that are approved by FERC and implemented by regional transmission organizations (RTOs) and ISOs across the United States. An example of such planning is the recent report submitted to the US DOE from the Eastern Interconnection Planning Collaborative (EIPC) that found, "Along with the benefits associated with the use of a relatively clean and cost-competitive fuel, increased

reliance on natural gas has exposed the increasing potential impact on bulk power system reliability from events that can reduce or interrupt gas supplies and deliveries." Looking ahead, the EIPC report concludes that, "The increase in gas demand for electric generation coupled with the lack of infrastructure expansions to serve gas-fired generators in certain PPAs [participating planning authorities] raises strategic concerns over pipeline and storage companies' ability to keep pace with the coincident requirements of gas utilities serving residential, commercial and industrial customers as well as the needs of gas-fired generating plants on peak demand days."[19]

Economywide impacts

The microeconomic impacts drive broader macroeconomic impacts that reflect the pace of premature uneconomic power plant closures generating a cost to the economy from diverting capital from other productive uses and increasing the retail price of electricity. The IHS Markit July 2017 baseline macroeconomic outlook provides a basis for evaluating the impacts of an electricity price shock due to a less efficient diversity case for power supply. The power price increases associated with the less efficient diversity case would profoundly affect the US economy. The less efficient diversity case IHS Markit US macroeconomic model simulations incorporated a 27% increase in average US retail power prices compared with the base case to assess the potential impact of the change in the level and variance of power prices between the base case and the less efficient diversity case.

Subjecting the current US economy to the less diverse US power supply portfolio power price increase would trigger economic disruptions, some lasting over a multiyear period. As a result, it would take almost a decade for these disruptions to peak and then dissipate. Econometric relationships in the IHS Markit macroeconomic model indicate how much producers and consumers would be affected by a 27% increase in retail electricity prices causing a similar increase in the Producer Price Index for electricity. The macroeconomic impacts indicate that higher electricity prices cause weaker consumer spending power as other goods and services become more expensive to produce. This, in turn, results in lower production, employment, and income.

Economic impacts of the power supply less efficient diversity case are quantified as deviations from the IHS Markit macroeconomic baseline simulations of the US economy. The major impacts within the three years after the power price change would include

- A drop in real disposable income per household of about $845 (2016 dollars)
- A reduction of 1 million jobs
- A decline in real GDP of 0.8%, equal to $158 billion (2016 chain-weighted dollars)

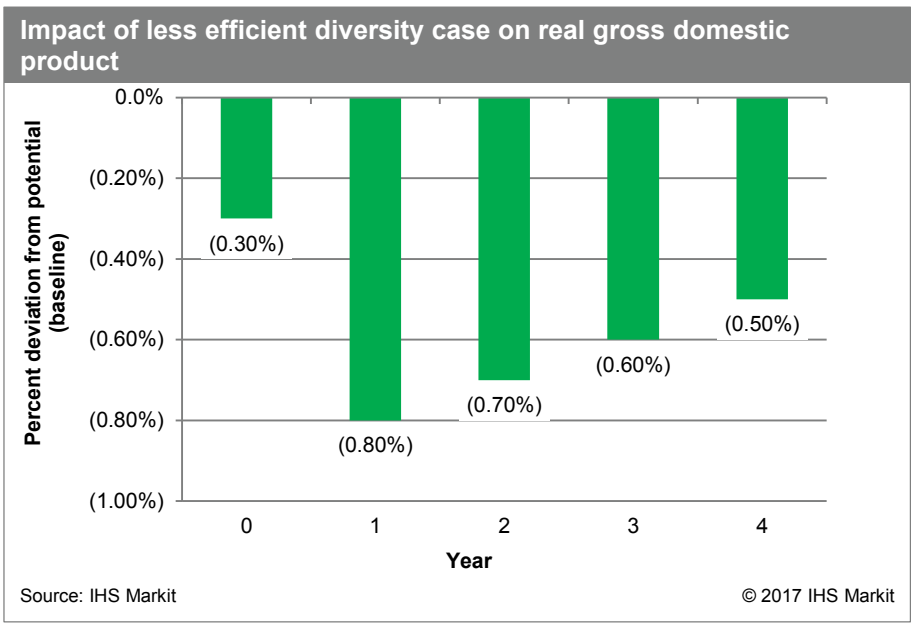
Impact on GDP and employment

The US economy is a complex adaptive system that seeks to absorb shocks (e.g., increases in prices) and converge toward a long-term state of equilibrium. The simulations conducted for this study do not project that the US economy will fall into a recession because of power price increases but are informative to gauge the underperformance of the US economy under the less efficient diversity case. In essence, the higher power prices resulting from the less efficient diversity conditions cause negative economic impacts equivalent to a mild recession relative to the forgone potential GDP of the baseline. The economic impacts

19. Levitan & Associates, Inc., *Gas-Electric System Interface Study: Existing Natural Gas-Electric System Interfaces*, DOE Award Project DE-OE0000343, Final Draft, 4 April 2014, p. 16, retrieved 31 August 2017.

of the less efficient diversity case lower real GDP by $61 billion in 2009 prices, or 0.3% of potential baseline output, in year 0, and about $140 billion in 2009 prices, or 0.8% of potential baseline output, in year 1 (see Figure 18). However, the impacts on consumers and businesses will be different, resulting in different impacts to the two major components of GDP—consumption and investment.

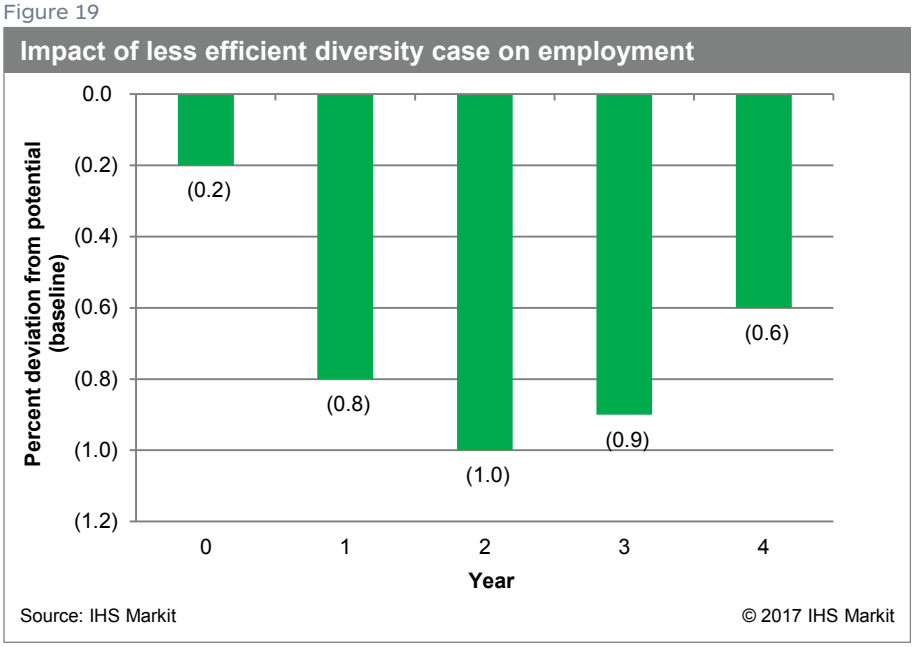
Figure 18



Businesses will face the dual challenge of higher operating costs in conjunction with decreased demand for their products and services. Consumers will bear the brunt of the impact of higher power prices. The higher price of electricity would trigger a reduction in power use in the longer run (10 or more years out), but changing those consumption patterns takes time. Depending on the time to adapt, household power bill increases would drain a further $82 per year from consumers' wallets, even as they face reduced buying power from higher prices economywide.

Industrial production will decline, on average, by about 0.8% through year 4. This will lead to fewer jobs (i.e., a combination of current jobs that are eliminated and future jobs that are never created) within a couple of years relative to the IHS Markit baseline forecast, with the largest impact appearing in year 2, with 1 million fewer jobs available (see Figure 19).

Figure 19



Household disposable income and consumption

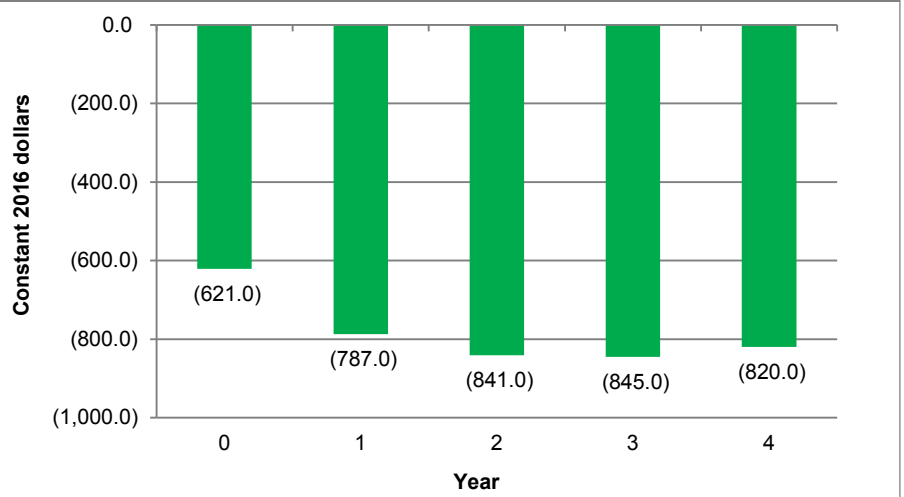
Some portion of increases in manufacturers' costs ultimately will be passed on to consumers through higher prices for goods and services. Faced with lower purchasing power, consumers will scale back on discretionary purchases because expected real disposable income per household is lower by approximately $760 (2009 dollars) three years after the electric price increase (see Figure 20). The net impact on consumers reflects labor market conditions. The unemployment rate is now approaching the level associated with full employment, and employed consumers are able to respond to higher prices by

demanding higher wages to some degree. On the one hand, this reduces the impact on consumers' wallets from the magnitude from even a few years ago. On the other hand, it exacerbates the inflationary impact on the economy, thereby reducing the Federal Reserve's range of options.

Analysis of personal consumption provides insights on the changes to consumer purchasing behavior under the less efficient diversity scenario conditions. Consumption, which accounts for approximately two-thirds of US GDP, falls 1.0% in response to higher electricity prices, with each of its three subcomponents—durable goods, nondurable goods, and services—displaying a different response to the less efficient diversity case conditions. In contrast with overall GDP, consumer spending shows little recovery by year 4 (see Figure 21). This is due to continued higher prices for goods and services and decreased household disposable income. Durable goods suffer the most in percentage terms, with a maximum gap of 2.3% below the baseline potential level as higher costs of production take their toll. However, services—which include electric utilities—experience the largest absolute impact, of $73 billion at 2009 prices (0.9%).

Figure 20

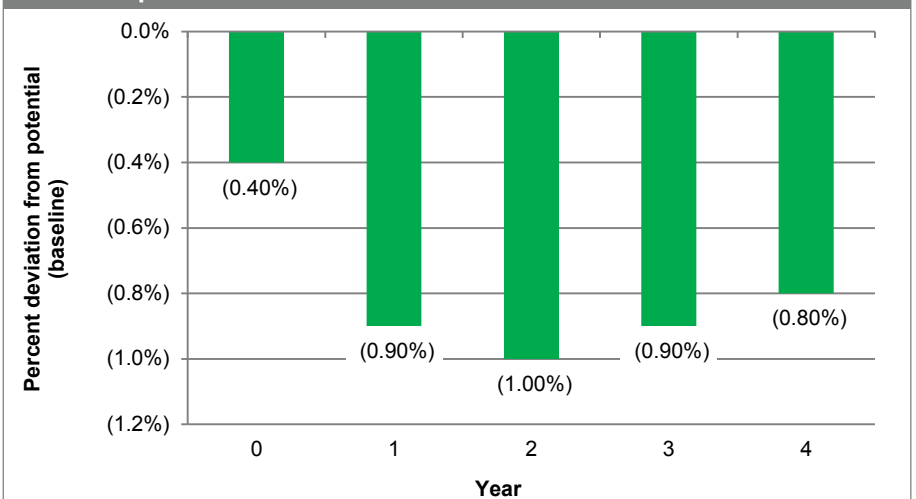
Impact of less efficient diversity case on real disposable income per household



Source: IHS Markit © 2017 IHS Markit

Figure 21

Impact of less efficient diversity case on private consumption at constant prices



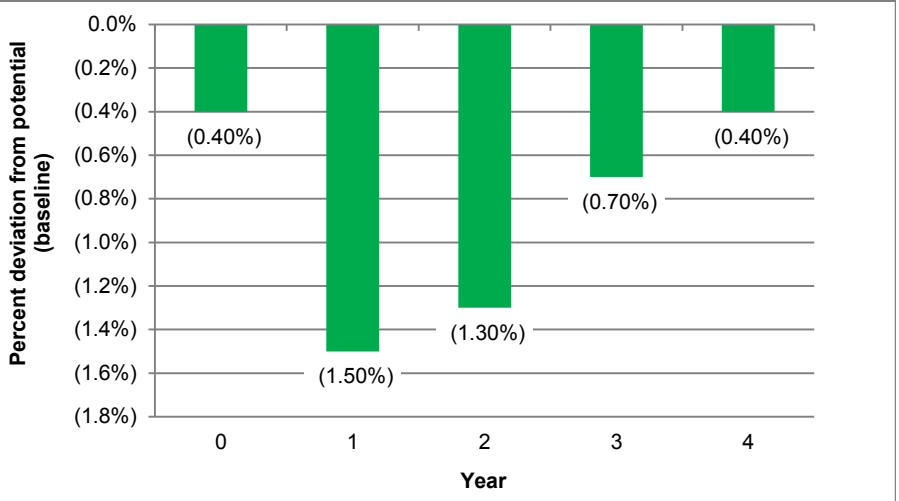
Source: IHS Markit © 2017 IHS Markit

The impact on durable goods is the largest but also the shortest-lived, suggesting that in response to a price increase, consumers will simply delay purchases. The US macroeconomic simulations also predict moderate delays in housing starts and light vehicle sales, ostensibly because of consumers trying to minimize their spending. Nondurable goods recover most slowly, implying that the equilibrium effect of long-term higher electricity prices will have the largest effect here.

Investment

Figure 22

Impact of less efficient diversity case on private fixed investment at constant prices



Source: IHS Markit © 2017 IHS Markit

Following an initial setback relative to the baseline, investment will recover by the end of the forecast horizon (see Figure 22). In dollar terms, the impact on investment is far smaller than on consumption, as investment is a smaller component of GDP. However, in relative terms, residential fixed investment in particular will fall far more, 2.7% below the baseline. Fixed investment in nonresidential structures will also fall in absolute terms, reaching a gap of 1.9% below the potential level in the baseline scenario. Investment in equipment and software will also suffer, quickly falling 1.6% below the baseline but rebounding rapidly as delays in equipment and software purchases moderate a few years after the electric price shock.

In the longer term, if current trends cause the less efficient diversity case to materialize within the next decade, then the premature closure and replacement of existing power plants would shift billions of dollars of capital from alternative deployments in the US economy.

Current electricity sector policy at a critical juncture

Comparing the expected electric industry performance in the less efficient diversity portfolio case with the actual industry performance in recent years quantifies what is at stake if nothing is done to arrest the erosion in the cost-effectiveness, resilience, and reliability of the current US power supply mix. A comparison of the current US electric supply portfolio outcomes from 2014 to 2016 with analyses of the expected outcome from the less efficient diversity portfolio case indicates that

- The current diversified US electric supply portfolio **lowers the cost of electricity production by about $114 billion per year and lowers the average retail price of electricity by 27%** compared with the less efficient diversity case.
- Avoiding the consumer adjustment to the higher retail prices in the less efficient diversity case preserves current levels of electric consumption and **avoids an annual $98 billion loss in consumer net benefits** from electricity consumption.
- The resilience of the current diversified US electricity portfolio to the delivered price risk profile of the fuel inputs to electric generation **reduces the variability of monthly consumer electricity bills by about 22%** compared with the less efficient diversity case.
- Preventing the erosion in reliability associated with a less resilient electric supply portfolio **mitigates an additional $75 billion per hour** cost associated with more frequent power supply outages that add to the current US average expected outage rate of 2.33 hours per year.

Comparing the broader economic impacts of the less efficient diversity case with the IHS Markit baseline simulations of the US economy indicates the following US macroeconomic impacts within three years of the retail price increase:

- The 27% retail power price increase associated with the less efficient diversity case causes a **decline of real US GDP of 0.8%, equal to $158 billion** (2016 chain-weighted dollars).
- Labor market impacts of the less efficient diversity case involve a reduction of **1 million jobs**.
- A less efficient diversity case r**educes real disposable income per household by about $845 (2016 dollars) annually**, equal to 0.76% of the 2016 average household disposable income.

Awareness is growing regarding the accumulating costs of the lack of harmonization between federal and state policy initiatives and wholesale electricity market operations. Former Secretary of Homeland Security Tom Ridge warned that, "Only a grid built on diverse and stable sources of energy can withstand evolving threats and keep the lights on throughout America."[20]

On 2–3 May 2017, FERC conducted a technical conference to garner input on possible approaches to reconcile state electricity policy initiatives with the federal objective of maintaining efficient market operations.

On 14 April 2017, the US Secretary of Energy, Rick Perry, asked for an assessment of the impact of current electricity market conditions on the efficiency and reliability of US power supply.[21] In August 2017, the DOE released the Staff Report to the Secretary on Electricity Markets and Reliability. Secretary Perry's press release on the study noted,

> It is apparent that in today's competitive markets certain regulations and subsidies are having a large impact on the functioning of markets, and thereby challenging our power generation mix. It is important for policy makers to consider their intended and unintended effects.[22]

The DOE report included policy recommendations and identified areas for further research, in particular, to

- Expedite FERC and RTO/ISO efforts to reform wholesale energy price formation.
- Define and support utility, grid operator, and consumer efforts to enhance system resilience.
- Conduct further research into reliability and resilience with resource diversity assessments.
- Conduct further research into market structure and pricing with assessments of the underrecognized contributions from base-load power plants.

This IHS Markit study responds to these growing concerns and to the DOE Staff Report recommendations for further research to support reforms in wholesale price formation, to identify resilience attributes, and to conduct resource diversity assessments.

The challenge of maintaining reliable, resilient, and efficient power supply currently puts the US power sector at a critical juncture. Doing nothing likely results in higher and more varied monthly power bills in the decades ahead, compared with doing something that preserves a more cost-effective US electric supply portfolio for consumers in the future.

20. Tom Ridge, "Keep nuclear in the nation's energy mix," Philly.com, 9 August 2017, retrieved 24 August 2017.

21. Secretary of Energy Rick Perry, Memorandum to the Chief of Staff, 14 April 2017, Subject: Study Examining Electricity Markets and Reliability.

22. Secretary of Energy Rick Perry, Press Release, 23 August 2017, retrieved 24 August 2017.

Actions to preserve the consumer net benefits of grid-based power supply range from the elimination or phaseout of market distortions and reforming market rules to implementing market interventions that offset the consequences of market distortions. Regardless of the approach, the objective is to achieve the reliability, resilience, technology, and fuel diversity and environmental profile expected from an undistorted efficient market outcome. To do this requires implementing appropriate operating and planning rules and standards at the federal, state, and RTO/ISO levels. Together, these changes can help preserve the net benefits to US consumers of a reliable, resilient, and cost-effective power supply portfolio.

Appendix I: US electric energy demand analyses

Quantification of US electric energy demand involves analysis of cross-sectional state-level data (50 states plus Washington, DC) for each consumer sector (residential, commercial, and industrial) in 2014.

Residential consumer electric energy demand

The specification of the residential consumer electric energy demand function is shown in Equation 1.

Equation 1:

$$Y_i = \beta_o + \beta_1 X_{1i} + \beta_2 X_{2i} + \beta_3 X_{3i} + \beta_4 X_{4i} + e_i$$

Where

i is the geographic region (state or Washington, DC).

Y_i is the natural log of the 2014 annual electricity consumption per residential customer (kilowatt-hours per customer).

β_0 is the intercept.

β_1 is the estimate of the long-run price elasticity of energy demand.

X_1 is the natural log of a five-year lagging average real price of electricity (2014 cents per kilowatt-hour).

β_2 is the estimate of the long-run income elasticity of energy demand.

X_2 is the natural log of the median household income (2014 dollars).

β_3 is the estimate of the temperature elasticity of energy demand.

X_3 is the natural log of the population-weighted average temperature (degrees Fahrenheit).

β_4 is the estimate of the net investment in ratepayer-funded efficiency programs' elasticity of energy demand.

X_4 is the natural log of the lagging 10-year accumulated net investment in ratepayer-funded efficiency programs per nonindustrial customer (2014 dollars per customer).

e is the error term.

Residential regression results

Since all variables are expressed as natural logs, the regression coefficients can be interpreted directly as elasticities of demand. Because price and income differences among states are long standing, the x-sectional approach provides estimates of long-run elasticities. In addition, since the state of technology changes through time, the x-sectional approach also holds the state of technology constant because it analyzes the variance in residential electric energy demand across states in a single year—an interval approximating a constant state of technology.

The adjusted R-squared statistic indicates that the four independent variables and the constant term forming the estimated equation together explain a high proportion (78%) of the observed variation among the states in residential electric energy consumption. The F-statistic indicates that the estimated equation provides statistically significant explanatory power because the probability that no relationship exists between the dependent variable and the independent variables is less than 1%. The multiple-R statistic indicates a high degree of correlation between the dependent variables' actual values and the values predicted by backcasting the estimated equation for the base year.

The signs and magnitudes of all the regression coefficients conform to expectations:

- **Price.** Rational utility-maximizing consumers subject to a budget constraint produce a downward-sloping aggregate demand curve and, thus, create the expectation of a negative price elasticity of demand. The estimated long-run price elasticity of demand is negative and falls within the range defined by other studies. An analysis of 36 studies published between 1971 and 2000 yielded 125 estimates of the long-run residential price elasticity of demand and found estimates ranging from –0.04 to –2.25 with a mean of –0.85 and a median of –0.81.[23]

  The estimated price coefficient is statistically significant based on conventional metrics. The null hypothesis is that no relationship exists with the dependent variable because the true value of the coefficient is zero. The T-statistic indicates that the probability of a type I error—rejecting this null hypothesis when it is true—is less than 1%.

- **Income.** Rational utility-maximizing consumers produce a positive-sloping aggregate Engel curve for a normal good or commodity and, thus, create the expectation of a positive income elasticity of demand. In addition, since the United States is a developed economy, the expectation is that the income elasticity will be in the inelastic range.

  The estimated income elasticity of demand is positive and inelastic. The null hypothesis is that no relationship exists with the dependent variable because the true value of the coefficient is zero. The T-statistic does not allow rejection of the null hypothesis based on conventional metrics employing a 5% or less probability of a type I error (rejecting this null hypothesis when it is true). As the upper and lower 95% probability ranges of the coefficient estimate indicate, there is about a 30% probability that the true value of the coefficient is less than or equal to zero. A priori expectations of the relationship between household income and residential electric consumption lead to the conclusion that a specification retaining the income variable and coefficient is preferable to dropping them from the estimated demand equation.

- **Average temperature.** Electricity demand is linked to heating and cooling requirements, and in the United States the seasonal cooling impacts are more powerful than seasonal heating impacts. As a result, the expectation is for a positive coefficient on the average temperature variable.

  The estimated coefficient is positive and statistically significant based on conventional metrics. The null hypothesis is that no relationship exists with the dependent variable because the true value of the coefficient is zero. The T-statistic indicates that the probability of a type I error (rejecting this null hypothesis when it is true) is less than 1%.

23. James A. Espy and Molly Espy, "Turning on the Lights: A Meta-Analysis of Residential Electricity Demand Elasticities," *Journal of Agricultural and Applied Economics* 36, no. 1 (2004).

- **Net investment in ratepayer-funded efficiency programs.** Initiatives to increase efficiency investments beyond what consumers choose to do otherwise result in lower electric energy consumption. As a result, the estimated coefficient is expected to be negative.

  The estimated coefficient is negative and statistically significant based on conventional metrics. The null hypothesis is that no relationship exists with the dependent variable because the true value of the coefficient is zero. The T-statistic indicates that the probability of a type I error (rejecting this null hypothesis when it is true) is less than 1%.

Commercial consumer electric energy demand

The specification of the commercial consumer electric energy demand function is shown in Equation 2.

Equation 2:

$$Y_i = \beta_o + \beta_1 X_{1i} + \beta_2 X_{2i} + \beta_3 X_{3i} + \beta_4 X_{4i} + e_i$$

Where

i is the geographic region (state or Washington, DC).

Y_i is the natural log of the 2014 annual electricity consumption per commercial customer (kilowatt-hours per customer).

β_0 is the intercept.

β_1 is the estimate of the long-run price elasticity of energy demand.

X_1 is the natural log of the five-year lagging average real price of electricity (2014 cents per kilowatt-hour).

β_2 is the estimate of the long-run production elasticity of energy demand.

X_2 is the natural log of the gross state product per commercial consumer by state (million 2014 dollars per customer).

β_3 is the estimate of the temperature elasticity of energy demand.

X_3 is the natural log of the population-weighted average temperature (degrees Fahrenheit).

β_4 is the estimate of the net investment in ratepayer-funded efficiency programs' elasticity of energy demand.

X_4 is the natural log of the lagging 10-year accumulated net investment in ratepayer-funded efficiency programs per nonindustrial customer (2014 dollars per customer).

e is the error term.

Commercial regression results

Since all variables are expressed as natural logs, the regression coefficients can be interpreted directly as elasticities of demand. Because differences in electric prices among states are long standing, the x-sectional approach provides estimates of long-run elasticities. In addition, since the state of technology

changes through time, the x-sectional approach also holds the state of technology constant because it analyzes the variance in commercial electric energy demand across states in a single year.

The adjusted R-squared statistic indicates that, together, the three independent variables and the constant term in the estimated equation explain a high proportion (82%) of the observed variation among the states in commercial electric energy consumption. The F-statistic indicates that the estimated equation has statistically significant explanatory power because the probability that no relationship exists between the dependent variable and the independent variables is less than 1%. The multiple-R statistic indicates a high degree of correlation between the dependent variables' actual values and the predicted values from the estimated equation.

The signs and magnitudes of all the regression coefficients conform to expectations:

- **Price.** A rational profit-maximizing commercial firm produces a downward-sloping derived demand curve for electric energy and, thus, creates the expectation of a negative price elasticity of demand.

  The estimated long-run price elasticity of demand is negative. The estimated coefficient is statistically significant based on conventional metrics. The null hypothesis is that no relationship exists with the dependent variable because the true value of the coefficient is zero. The T-statistic indicates that the probability of a type I error (rejecting this null hypothesis when it is true) is less than 1%.

- **Gross state product per customer.** Electricity is an input into most production functions in the economy. Therefore, an expectation exists for a positive coefficient.

  The estimated coefficient is positive and statistically significant based on conventional metrics. The null hypothesis is that no relationship exists with the dependent variable because the true value of the coefficient is zero. The T-statistic indicates that the probability of a type I error (rejecting this null hypothesis when it is true) is less than 1%.

- **Average temperature.** Electricity demand is linked to heating and cooling requirements, and in the United States the seasonal cooling impacts are more powerful than seasonal heating impacts. As a result, the expectation is for a positive coefficient on average temperature variable.

  The estimated coefficient is positive and statistically significant based on conventional metrics. The null hypothesis is that no relationship exists with the dependent variable because the true value of the coefficient is zero. The T-statistic indicates that the probability of a type I error (rejecting this null hypothesis when it is true) is less than 1%.

- **Net investment in ratepayer-funded efficiency programs.** Initiatives to increase efficiency investments beyond what consumers choose to do otherwise result in lower electric energy consumption. As a result, the estimated coefficient is expected to be negative.

  The estimated coefficient is negative and statistically significant based on conventional metrics. The null hypothesis is that no relationship exists with the dependent variable because the true value of the coefficient is zero. The T-statistic indicates that the probability of a type I error (rejecting this null hypothesis when it is true) is less than 1%.

Industrial consumer electric energy demand

The industrial consumer electric energy demand function is shown in Equation 3.

Equation 3:

$$Y_i = \beta_0 + \beta_1 X_{1i} + \beta_2 X_{2i} + e_i$$

Where

i is the geographic region (state or Washington, DC).

Y_i is the natural log of the 2014 annual electricity consumption per industrial customer (kilowatt-hours per customer).

β_0 is the intercept.

β_1 is the estimate of the long-run price elasticity of energy demand.

X_1 is the natural log of the trailing five-year average real price of electricity (2014 cents per kilowatt-hour).

β_2 is the estimate of the long-run production elasticity of energy demand.

X_2 is the natural log of the gross state product per industrial customer (million 2014 dollars per customer).

e is the error term.

Industrial regression results

Since all variables are expressed as natural logs, the regression coefficients can be interpreted directly as elasticities of demand. Because differences in electric prices among states are long standing, the x-sectional approach provides estimates of long-run elasticities. In addition, since the state of technology changes through time, the x-sectional approach also holds the state of technology constant because it analyzes the variance in commercial electric energy demand across states in a single year.

The adjusted R-squared statistic indicates that, together, the two independent variables and the constant term in the estimated equation explain a high proportion (61%) of the observed variation among the states in industrial electric energy consumption. The F-statistic indicates that the estimated equation provides statistically significant explanatory power because the probability that no relationship exists between the dependent variable and the independent variables is less than 1%. The multiple-R statistic indicates a high degree of correlation between the dependent variables' actual values and the predicted values from the estimated equation.

The signs and magnitudes of all the regression coefficients conform to expectations:

- **Price.** A rational profit-maximizing industrial firm produces a downward-sloping derived demand curve for electric energy and, thus, creates the expectation of a negative price elasticity of demand.

  The estimated long-run price elasticity of demand is negative. The magnitude of the coefficient aligns with previous research. A survey of the literature for the US DOE by Carol Dahl in 1993 found a wide disparity in estimates for both commercial and industrial price elasticities, ranging from –1.03 to –1.94. The estimated coefficient is statistically significant based on conventional metrics. The null hypothesis is that no relationship exists with the dependent variable because the true value of the coefficient is

zero. The T-statistic indicates that the probability of a type I error (rejecting this null hypothesis when it is true) is less than 1%.

- **Gross state product per customer.** Electricity is an input into most production functions in the economy. Therefore, an expectation exists for a positive coefficient.

  The estimated coefficient is positive and statistically significant based on conventional metrics. The null hypothesis is that no relationship exists with the dependent variable because the true value of the coefficient is zero. The T-statistic indicates that the probability of a type I error (rejecting this null hypothesis when it is true) is less than 1%.

The industrial consumer electric energy demand equation specification excludes a net investment in ratepayer-funded efficiency programs because these programs are focused primarily on the nonindustrial consumer segments. The specification also does not include population-weighted average temperature as an independent variable because space conditioning is not a major electric end use in the industrial sector.

Appendix II: Electricity storage paradox

Advances in the cost and performance of electric storage technologies are often expected to improve the cost-effectiveness of intermittent renewable technologies versus conventional generation technologies. However, comparing the costs of combining storage with intermittent and conventional generation produces the paradox that the availability of cost-effective electric storage can free intermittent resources from integration with conventional generation without improving the cost position of intermittent generating technologies versus conventional generating resources.

A simple example illustrates the electricity storage paradox by comparing the cost to meet an increment of power demand with combinations of storage and generating technologies. Suppose a power system has an increase of 1 MW of demand at time of peak with a system load factor of 57%. As a result, the increase in electric energy demand associated with the increase in the peak demand is 5,000 MWh.

Table 12 provides cost and performance characteristics for the conventional generation and wind technologies employing The National Academies of Sciences, Engineering, and Medicine estimates of LCOE for new power supply. The wind capacity derate factor employs the ERCOT wind capacity derate factor.

Table 12

Electricity storage paradox: Cost and performance characteristics for conventional generation and wind technologies

Attributes	Conventional generating technology	Wind turbine
Annual fixed cost per MW	$68,182	$212,500
Capacity derate at time of peak	10%	90%
Annual variable cost per MWh	$50/MWh	$0/MWh
Plant factor	0–90%	30%
Annual average stand-alone levelized $/MWh cost	$65/MWh	$85/MWh

Source: IHS Markit; The National Academies of Sciences, Engineering, and Medicine © 2017 IHS Markit

Without an economic storage technology, meeting an increase of 1 MW of demand reliably and producing 5,000 MWh involves building 1.1 MW of firm conventional flexible dispatchable generation and utilizing this capacity at the 52% annual plant factor.

An alternative involves building wind capacity integrated by conventional flexible dispatchable generating technology. In this example, the 1 MW of incremental demand is met by 1 MW of wind capacity along with enough conventional flexible dispatchable generating capacity to produce 1 MW of firm capacity along with generating energy to back up and fill in for the intermittent wind in order to produce the required 5,000 MWh. In this integrated technology case, building 1 MW of wind will provide 0.1 MW of firm capacity at time of peak, and, therefore, the wind resource requires integration with 1 MW of the conventional flexible dispatch technology to reliably meet the peak demand. The 1 MW of wind running at the 30% plant factor produces 2,628 MWh across the year. Therefore, the conventional flexible dispatchable generating technology runs at a 27% plant factor to generate the remaining 2,372 MWh to satisfy the power system energy requirements. The end result involves a 52% renewable generation share.

Table 13 provides a comparison of the cost to meet an increment of power demand from the alternative electric supply options.

The cost and performance of the current state of electric energy storage technologies results in limited electric energy storage in electric power systems beyond what is available from natural endowments such as reservoir hydroelectric resources. As a result, the most cost-effective way to meet the ups and downs of power system net load involves building additional generating capacity beyond what is needed to produce the annual energy requirement.

Electric inventory is cost-effective if it can meet the ups and downs in net load at a lower cost than employing the conventional flexible dispatchable load following generating technologies. Therefore, an assessment of the impact of cost-effective electric storage incorporates a cost of a battery technology that can charge and discharge to meet the ups and downs in net load at a fixed cost that is lower than the fixed cost of the flexible dispatchable generating technology. For example, the impact of economic electric storage technology can involve a technology scenario in which a battery technology can substitute for load following generating technologies at a 10% lower fixed cost per megawatt than conventional flexible dispatchable generating capacity. In the case of available cost-effective battery technology to meet the ups and downs of power system net load, the increment in power system demand can be satisfied by either integrating battery storage with the conventional generating technology or with the wind turbine technology.

Table 13

Electricity storage paradox: Cost to meet an increment of power demand from the alternative electric supply options

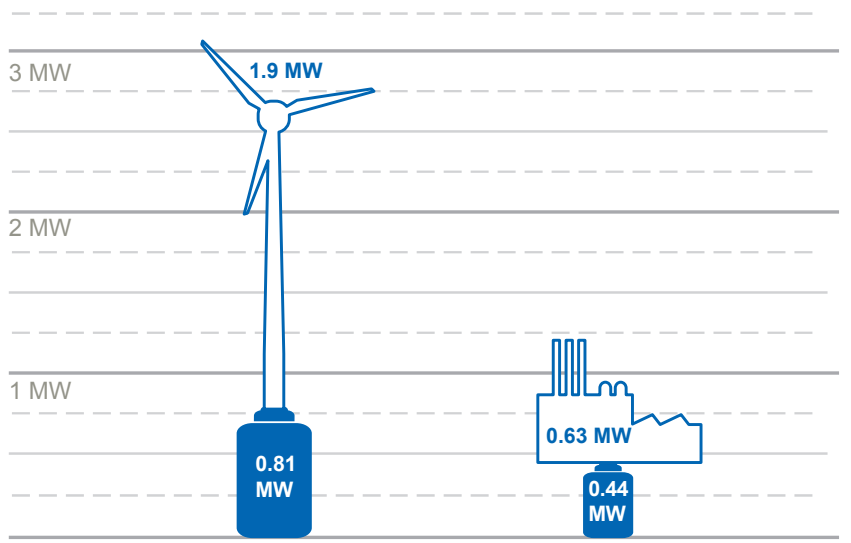
Costs to meet incremental power demand	1.1 MW conventional flexible dispatchable generating technology	1 MW wind turbine technology integrated with 1 MW conventional flexible dispatchable generating technology
Annual fixed cost	$75,000	$280,682
Annual variable cost	$250,000	$118,600
Total annual generating cost	$325,000	$399,282
Total cost per MWh	$65/MWh	$79.86/MWh
Cost ratio to conventional flexible dispatchable generating technology	1.00	1.23

Source: IHS Markit © 2017 IHS Markit

Storage can complement either conventional or wind generating technologies in meeting a 1 MW and 5,000 MWh increment of electric demand. On the one hand, the conventional generating technology can produce the annual energy requirement with the maximum utilization of 0.63 MW generating capability throughout the year. Therefore, meeting the peak demand with a firm megawatt of capacity requires a battery with 0.44 MW of discharge capacity. On the other hand, the wind technology can produce the annual energy requirement with a maximum utilization of 1.9 MW of capacity throughout the year. Therefore, meeting the peak demand with a firm megawatt of capacity requires a battery with 0.81 MW of discharge capability (see Figure 23).

Figure 23

Energy storage: 1 MW of demand with 5,000 MWh of energy



Source: IHS Markit © 2017 IHS Markit:1695666

Table 14 compares the cost to meet a 1 MW and 5,000 MWh increment of electric demand with an integration of cost-effective battery technology with conventional versus wind generating technologies.

In this simple example, the relative cost of integrated wind increased from 1.23 to 1.42 times the cost of the conventional generation technology alternative when wind integration shifted from cost-effective conventional flexible dispatchable generation technology to cost-effective storage technology.

Table 14

Electricity storage paradox: Cost to meet an increment of power demand from the alternative electric supply options

Costs to meet incremental power demand	0.63 MW conventional generating technology integrated with 0.44 MW battery	1.9 MW wind turbine technology integrated with 0.81 MW battery
Annual fixed cost	$69,954	$453,454
Annual variable cost	$250,000	$0
Total annual generating cost	$319,954	$453,454
Total cost per MWh	$63.95/MWh	$90.69/MWh
Cost ratio to conventional flexible dispatchable generating technology	1.00	1.42

Source: IHS Markit

The storage paradox is that the integration of cost-effective electric storage is not likely to increase the penetration of intermittent generating technologies in meeting an increment of power system electric demand owing to the relative costs of the alternative of integrating storage with high-utilization conventional generating technologies.

The impact of cost-effective inventory on electric production is not an anomaly. Market forces typically create consumer benefits by driving producers in a wide range of industries to lower costs by running factories at high utilization rates and using cost-effective inventory levels to manage variations in consumer demand through time.

The potential for cost-effective inventory to favor high-utilization generating technologies is a paradox because interest in expanding electricity storage reflects the technology-specific objective of increasing the penetration of intermittent renewable technologies by reducing the intermittency of output patterns. However, this technology-specific perspective creates a blind spot regarding the potential impact of cost-effective storage. From the technology perspective, integration of cost-effective storage can achieve the objective of mitigating the intermittency of wind or solar generation. By contrast, from the consumer perspective, the objective is not to maximize the impact of storage on a particular technology but rather to maximize the impact of storage in the overall electricity supply portfolio. As a result, from a consumer perspective, the impact of cost-effective electricity storage in favoring the integration of inventory with high-utilization production technologies is not a paradox.

Appendix III: Wholesale market distortions in ERCOT, PJM, and California

Subsidies and mandates of intermittent wind and solar resources result in installed capacity levels beyond the cost-effective level and intermittent generation shares beyond their cost-effective generation shares. Consequently, electricity supply costs are higher than they need to be. These market distortions suppress market-clearing wholesale prices from the levels expected in an undistorted electricity market outcome and, as a result, disrupt timely and efficient power supply investment and decrease power system resilience to risk factors in the power system operating environment. Power system examples in ERCOT, PJM, and California illustrate these impacts.

ERCOT

Texas provides an example of state policies that mandated and subsidized renewable resources to push wind generation shares beyond the cost-effective level.

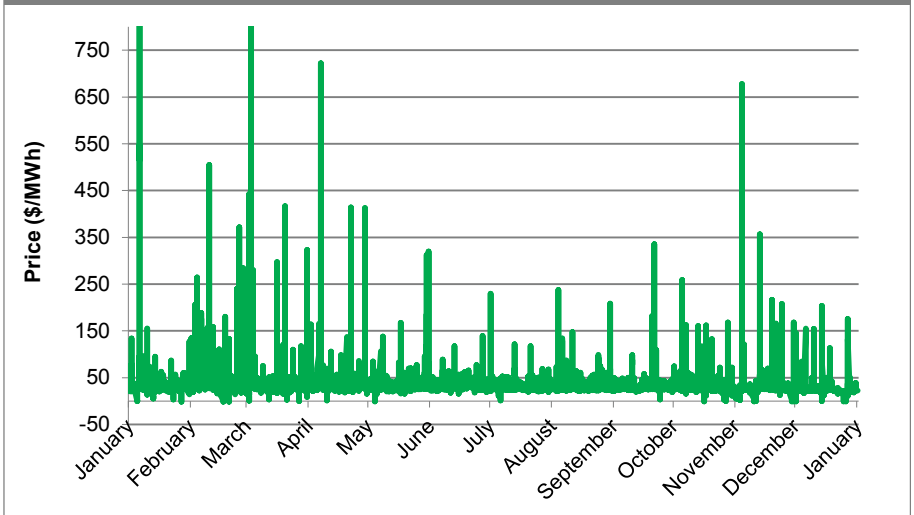
The EIA estimates that the unsubsidized levelized cost for wind entry in the United States is between $41/MWh (2015) and $71/MWh (2015). The above-average wind conditions in Texas put the unsubsidized levelized cost of ERCOT wind entry at the low end of this range, but these cost assessments do not include any incremental transmission costs, such as the $6.3 billion invested in CREZ transmission in Texas to accommodate wind output.

ERCOT wholesale market-clearing prices do not cover the unsubsidized cost of wind entry. For example, Figure 24 shows that the average ERCOT hourly price was $36.49/MWh in 2014.

A comparison of the pattern of wind output in ERCOT shown in Figure 25 to the pattern of aggregate consumer demand shown in Figure 26 indicates that wind output is disproportionately off peak, when market-clearing prices are lower. This misalignment of wind output to consumer demand led to the

Figure 24

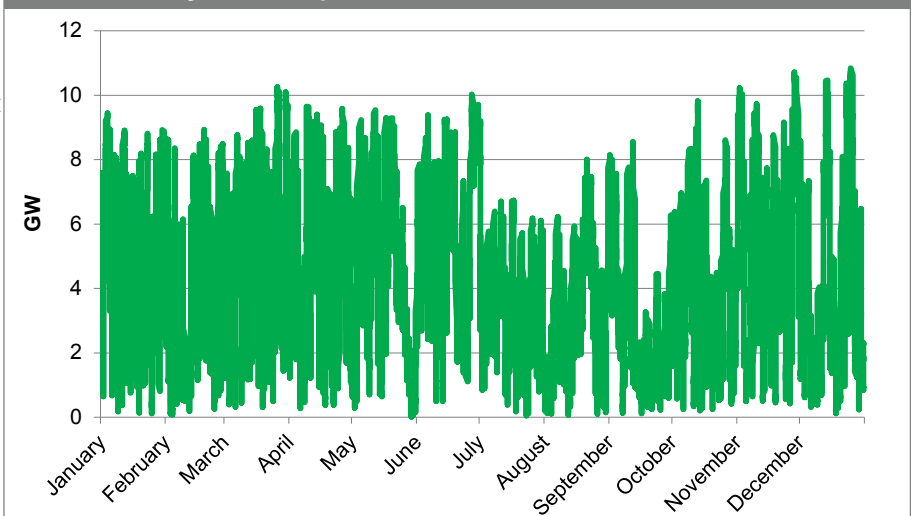
ERCOT: $36/MWh average price, 44 hours of negative prices, 2014



Source: IHS Markit, ERCOT © 2017 IHS Markit

Figure 25

ERCOT hourly wind output, 2014

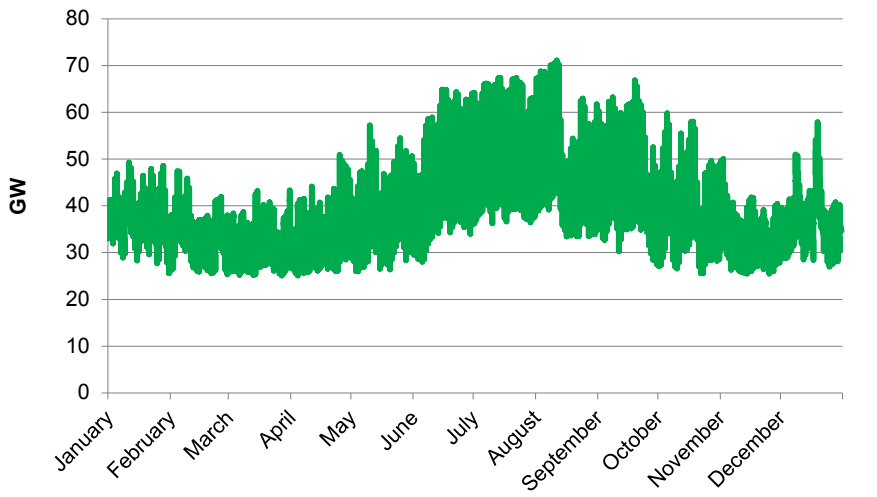


Source: IHS Markit, ERCOT © 2017 IHS Markit

overgeneration conditions that produced the negative ERCOT wholesale prices shown in Figure 24. The bottom line is that the shortfall in ERCOT wholesale market-clearing prices covering the entry costs of unsubsidized wind are even greater when the realized average price reflects price levels when the wind blows or when the incremental generation costs of transmission are also included. The implication is that the ERCOT wind resource generation share exceeds the cost-effective level.

Figure 26

ERCOT aggregate hourly demand, 2014



Source: IHS Markit © 2017 IHS Markit

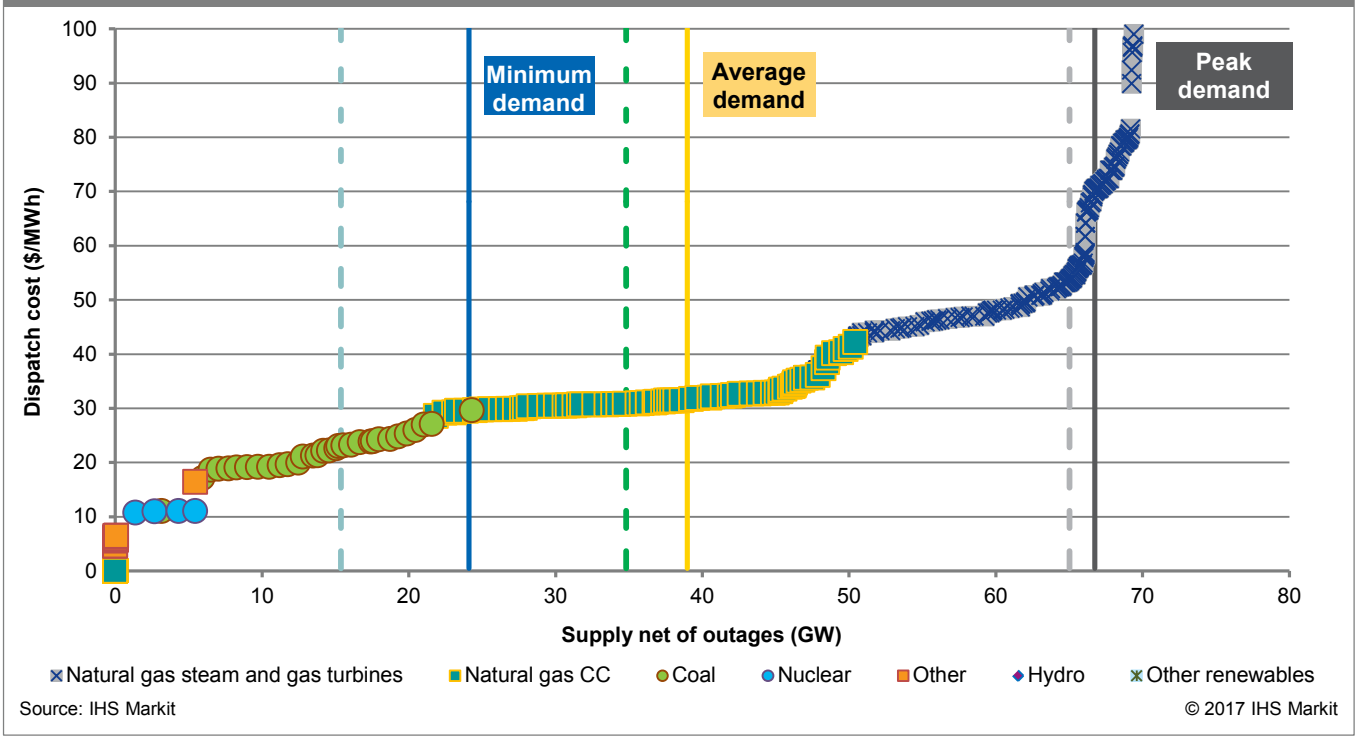
The difference between ERCOT aggregate consumer hourly load and the hourly wind output is the ERCOT net load. Although the wind generation share exceeds the cost-effective level, the majority of ERCOT net load is still a stable, constant base net load. Therefore, the current cost-effective ERCOT power supply portfolio still includes a relatively large share of resources that are the most cost-effective technologies and fuel sources operating in a high-utilization mode of operation to serve the base net-load segment of power system demand.

ERCOT wind output suppresses ERCOT wholesale market-clearing prices. This wholesale price suppression can be graphically illustrated for recent interactions between ERCOT supply and demand curves. Figure 27 shows the ERCOT wholesale market supply curve as an aggregation of price-sensitive power supply from rival generators that want to dispatch resources when the market price is above the SRMC. On the demand side, the impact of wind entry can be analyzed as reducing the market demand curve from aggregate load to aggregate net load (aggregate load minus wind generation).

Figure 27 shows a demand curve leftward shift at time of peak that is about 1 GW, and this is consistent with the 8.7% effective load-carrying capability that ERCOT assigned to the 11 GW of 2014 installed wind. As a result, ERCOT wind output reduced the market-clearing wholesale price by about one-third during the 2014 peak-demand period. In that year, the ERCOT market did not have surplus firm nonwind generating supply. However, the impact of the wind output postponed the market investment price signal.

In ERCOT, the simple-cycle CT technology is the least-cost option for supplying the peak-demand segment of aggregate consumer demand. The 2014 CT utilization rate in ERCOT was 16.4%. At this utilization rate, the LRMC (LCOE) of the ERCOT peaker technology was about $111/MWh. The 2014 ERCOT market-clearing prices over the top 16.4% of 2014 hours averaged $77.87/MWh. The 2014 peak-period graphical interaction of the ERCOT market demand and supply curves shows that wind output changed the intersection of the demand and supply curves enough to lower prices by about one-third. The implication is that without the policy-driven wind supply, the market-clearing price in the ERCOT market would have been about one-third higher—closing most of the gap between market-clearing prices and the cost of new entry (CONE).

Figure 27



The 2014 ERCOT example illustrates that the policy-driven expansion of wind resources postpones the point in time when demand and supply adjustments achieve long-run market balance and the wholesale price reflects the CONE.

A mechanism exists in ERCOT to prevent underinvestment in capacity when new firm capacity is needed. ERCOT has an ORDC designed to close the gap to the CONE when the capacity reserve reaches a critical level of scarcity.

ERCOT wind output wholesale price suppression around the average load segment of consumer demand is relatively modest because the supply curve is relatively flat. However, wind entry lowers the load factor for remaining electric supply and, thus, increases the average costs associated with the reoptimization of the resource portfolio to include less investment in production efficiency compared with the market outcome without wind generation in excess of the cost-effective share. In addition, operating costs increase as wind entry increases the frequency of load following power plant starts and stops and ramps up and down for net load–following power plants.

ERCOT wind output price suppression has a big impact in off-peak hours. Wind can account for about 40% of supply during some off-peak hours. Therefore, lower prices squeeze cash flows and cause investment to shift toward less efficient generating technologies compared with the unfettered market outcome that produces prices that support high-utilization generating technologies cost-effectively aligned with power system base net load.

PJM

Many states within the PJM electric system mandated renewable generation shares beyond what is cost effective, causing market price distortions. The majority of renewable resource development in PJM involves wind technologies.

Selling wind output in PJM during 2015 at market-clearing prices yielded an average wind output weighted wholesale price of $34.40/MWh. The EIA estimates that the unsubsidized levelized cost for wind entry in the United States is between $41/MWh (2015) and $71/MWh (2015). The 2015 PJM market monitor report indicates that PJM wind entry costs are at the high end of the EIA range and that PJM wind entry is typically uneconomic without subsidies.[24]

Figure 28

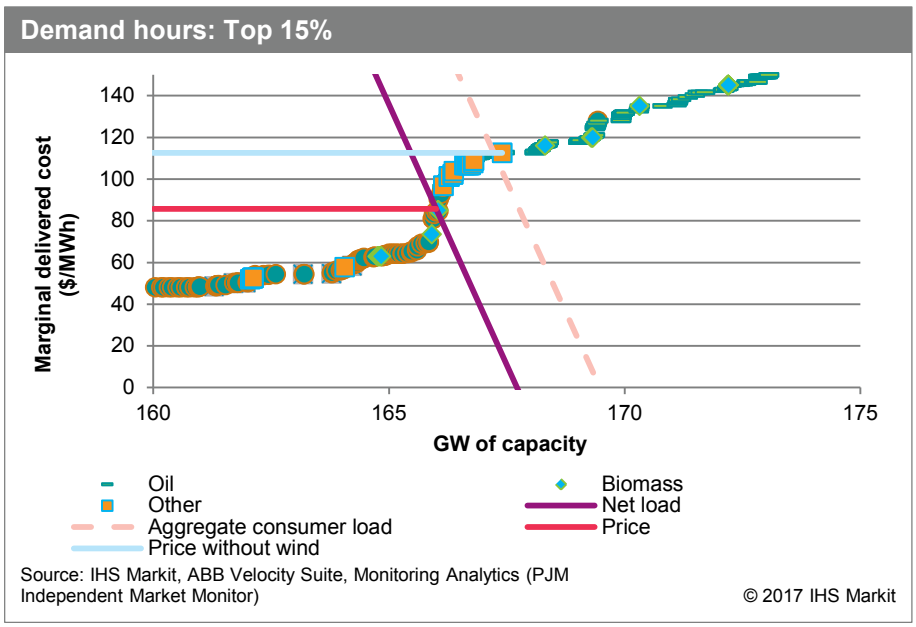
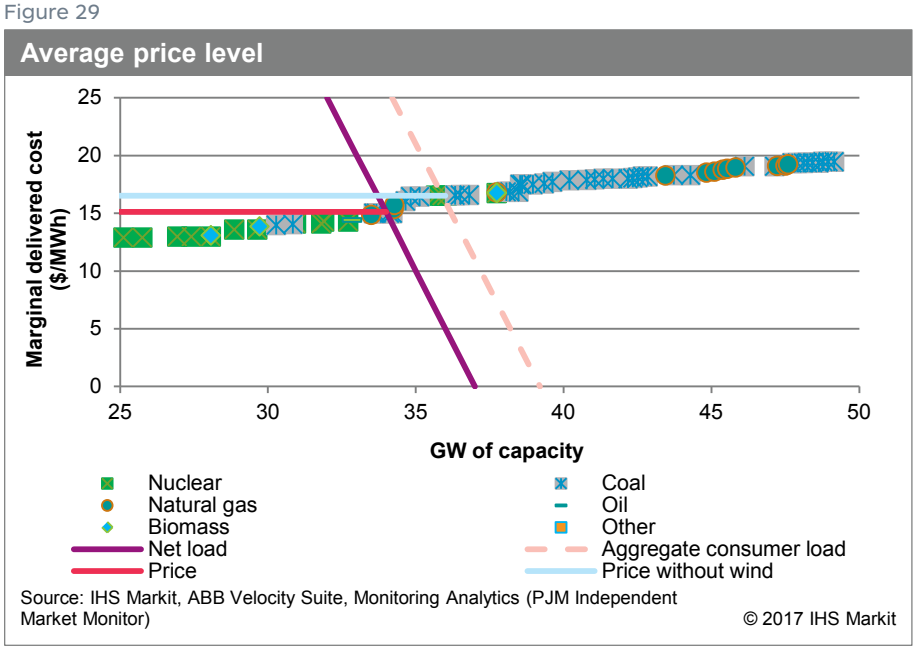


Figure 29



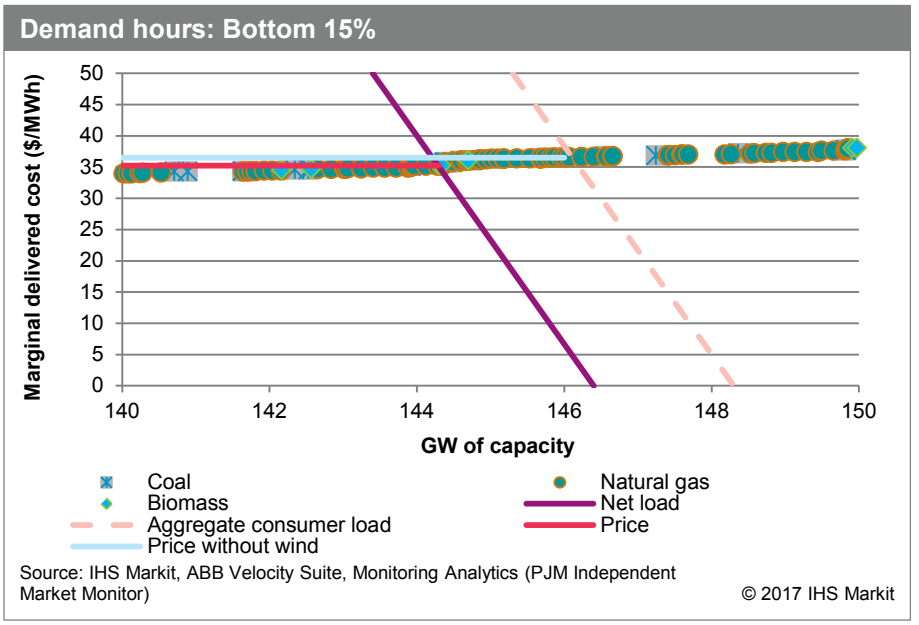
Mandates of subsidized wind and solar generation shares beyond the cost-effective shares in states within the PJM power system suppress wholesale energy prices. This wholesale price suppression can be graphically illustrated by the recent interactions of PJM supply and demand curves. Figures 28–30 shows the intersection of the 2015 PJM electricity market demand and supply curves during three different demand intervals and with two market demand curves reflecting aggregate consumer load and net load (aggregate consumer demand less wind output). The supply curve is the cumulative, ordered incremental generating costs (including average zonal transmission congestion costs) of the derated (based on typical forced outage rates) nonwind installed generating capacity.

The market demand and supply interactions show that wind output suppressed prices by about 24% during the 15% of the maximum 2015 net-load hours when rival peaking technologies were setting the price. Wind output suppressed prices by about 4% during the 15% of hours around average net load and by around 9% during the minimum net-load interval.

24. Monitoring Analytics, *2015 State of the Market Report for PJM*, Volume II, Section 7 ("Net Revenue"), 2016, retrieved 24 August 2017.

Wind output suppressed 2015 PJM energy market cash flows to generators. Price suppression lowered cash flow from the revenue side. On the cost side, generators incurred less production efficiency and higher O&M costs owing to the need to start and stop output and ramp output up and down more frequently to compensate for the impact of wind on the sequential hourly net-load pattern.

Figure 30



As long as subsidized mandates for renewables delay market adjustments to a long-run demand and supply balance, wholesale price suppression currently affects all generators in PJM. However, the impacts on the PJM generator cash flows eventually differ by technology type in the generation portfolio when the market achieves balance in the long run.

The technologies that cost-effectively align with the variable segments of consumer demand face delayed recovery of wholesale prices to support the net cost of new entry (net CONE) due to mandates for renewables postponing market balance. A capacity market is designed to clear at a price level that, in conjunction with the energy price level, fully covers the LRMC of a peaking technology. The LRMC is described as the CONE, and the CONE minus the costs covered by the margins in the energy market is the net CONE. A well-structured capacity market drives prices to the net-CONE level when the market is in long-run balance. Therefore, if market demand and supply adjustments eventually accommodate the policy-driven renewable supply additions and reach long-run balance, then even with continued wholesale energy price suppression during the peak demand period, capacity markets should produce an offsetting increase in the market-clearing price of capacity to cover the higher net CONE of the least-cost peaking technology.

The electric generating technologies that are cost-effectively aligned with the base-load segment of consumer demand do not have an offsetting mechanism like the capacity market to close the gap to the CONE in the long run. Instead, when market demand and supply for capacity are in balance, continued wholesale energy price suppression and negative prices will still arise during the overgeneration periods when net load is below the sum of wind output, inflexible generation, out-of-merit order dispatch (network security constraint-driven dispatch), and minimum operating spinning reserves required to back up intermittent resources.

Periods of overgeneration and negative market-clearing prices expose an underlying flaw in electricity market price formation. Such conditions caused 25 hours of negative PJM market-clearing energy prices in 2015. During these periods, production cost minimization requires reducing supply or increasing net load from the least-cost options during periods of overgeneration. However, wind-on-wind competition to avoid curtailment involves the opportunity cost of losing the volume-based subsidy. Consequently, the renewable bids reflecting this subsidy generate curtailment bids that lead to more expensive resource curtailment and negative market-clearing prices. Under these conditions, the market-clearing prices

do not reflect the positive SRMC of the resources running to provide the security-constrained dispatch for the power system. Such results aggravate the existing problem that adjustments to market-clearing wholesale prices to accommodate the security constraints of generation dispatch do not fully reflect the marginal costs of generating resources operating to satisfy system requirements.

California

California provides an example of a political process generating policies to increase subsidized wind and solar generation shares beyond cost-effective levels. California began mandating wind and solar generation in 2002 and ratcheted up the mandates five times to the current requirement that 50% of power supply come from renewable resources by 2030.

Governor Jerry Brown signed Senate Bill (SB) 350—The Clean Energy and Pollution Reduction Act of 2015—into law in December 2015 and thereby increased the renewable generation requirement for California retail electric suppliers to 50% by 2030. Senator Kevin de León and Senator Mark Leno formulated SB 350 based on a renewable cost assessment utilizing simple, LCOE comparisons that ignored the effect of time dimension of balancing electricity demand and supply. The authors of SB 350 asserted that the substitution of wind and solar power for conventional electric generating technologies would reduce GHG emissions at no additional cost because of the perceived cost parity of wind and solar technologies versus conventional electric generating technologies. The authors observed that

> Renewable energy is as cost-effective as fossil fuels and produces much less pollution. According to the International Renewable Energy Agency, renewable power generation costs in 2014 were either as cheap as or cheaper than coal, oil, and gas-fired power plants—even without financial support and despite drops in oil prices. Solar-powered energy has had the largest cost decline, with solar PV (rooftop solar) being 75 percent less expensive than it was in 2009.[25]

California electricity policy involves continued ratcheting up of renewable energy mandates despite accumulating evidence of the importance of the time dimension on the cost of balancing electric system demand and supply. In 2013, the major California utilities sponsored a study led by Nancy Ryan, a former commissioner at the California Public Utilities Commission, to analyze the consequences of operating the CAISO with the ratcheting up of the renewable power mandate to a 33% generation share.[26] The study report, submitted to the Western Conference of Public Service Commissioners, indicated that significant cost consequences resulted from the impact of intermittent generation on the power system net load (aggregate consumer electricity demand less intermittent wind and solar output). The graphic illustrating this mounting challenge showed how the shape of net load changed as the generation share of intermittent renewables increased. Subsequent versions of this curve—as illustrated in Figure 31—showed that as the generation share of renewables increased, the electric system net-load shape increasingly resembled the shape of a duck, and, as a result, the chart became known as the "duck curve."

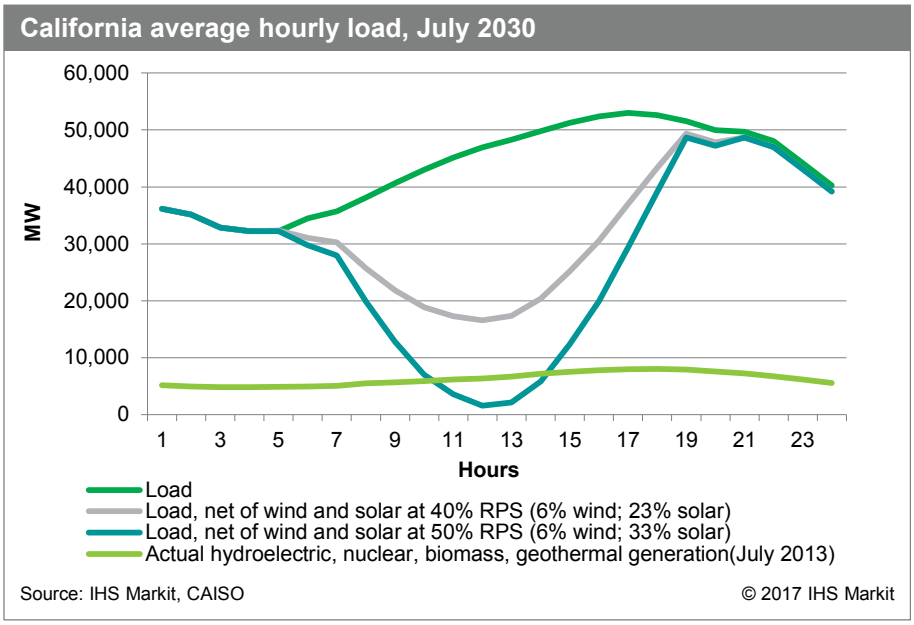
The duck curve illustrates the mounting operational challenges posed by the increasing ramping requirements imposed on the flexible, dispatchable generating resources to fill in generation as solar intensity and thus generation declines. The power system operational consequences of the California renewable mandates caused California to expand its flexible natural gas–fired generating technologies by 30% between 2002 and 2016 to back up and fill in for the intermittent generating resources. As a result, California increased its in-state generation share for fossil fuels from 52% to 62%.[27]

25. SB 350: Golden State Standards, retrieved 24 August 2017.

26. Energy and Environmental Economics, *Investigating a Higher Renewables Portfolio Standard in California*, January 2014, retrieved 24 August 2017.

27. California Energy Commission, Energy Almanac, retrieved 31 August 2017.

Figure 31



Currently, intermittent wind and solar resources account for 16% of the electricity generated in California. Already, the intermittent output patterns of wind and solar result in some hours when wind and solar output supply exceed 50% of the state's aggregate consumer demand. Consequently, mandates of wind and solar output increased the frequency and duration of overgeneration conditions where net-load levels fall below the output of hydroelectric, biomass, and geothermal resources as well as nuclear and dispatchable resources running at minimum load for security of supply requirements. Under these conditions, the variability of wind and solar output and the variability of hydroelectric output result in significant curtailments of renewable output and spilling of hydroelectric resources.

Suppressed wholesale prices and the increased frequency of overgeneration conditions producing negative market-clearing prices reduced market-based cash flows for electric generation in California. The CAISO Department of Market Monitoring reported a chronic shortfall of cash flow for the existing capacity that provided the operational flexibility to integrate large volumes of intermittent generation.[28]

Chronically suppressed wholesale electricity market cash flows contributed to the decisions to prematurely close the San Onofre and Diablo Canyon nuclear power plants. The closure of the San Onofre nuclear power plant in 2012 removed 8% of non–carbon-emitting generation from the California in-state supply portfolio and caused a 30% increase in the carbon intensity of in-state generation. An impact assessment from the Energy Institute at the Haas School of Business at the University of California, Berkeley, found that the San Onofre closure caused an increase in California in-state natural gas–fired generation and did not provide savings to consumers because the closure caused an estimated 15% increase in California electric generation costs by contributing to the 31% increase in wholesale power prices in 2013 versus 2012.[29]

Although the rationale for California renewable mandates involved reducing electricity sector CO_2 emissions, the outcome of expanded natural gas use and the uneconomic retirement of nuclear power plants was that California in-state electric generation CO_2 emissions did not trend downward from 2002 to 2015.

The California experience indicates that the objective to increase wind and solar generation shares is not the same as the objective to lower power system CO_2 emissions and that power systems likely reach

28. CAISO Department of Market Monitoring, *2013 Annual Report on Market Issues and Performance*, 28 April 2014, retrieved 24 August 2017.

29. Lucas Davis and Catherine Hausman, "Market Impacts of a Nuclear Power Plant Closure," *American Economic Journal: Applied Economics* 8, no. 2 (April 2016): 92–122.

significant operational limits with wind and solar generation shares well before these intermittent resources make up a majority share of annual generation in the supply mix.

The market interventions in California contributed to the California retail electricity price increasing by 33% from 2005 to 2015 compared with the US average retail price increase of 26%, causing the current California average retail electricity price to move to 50% above the US average.

IHS Markit Customer Care

CustomerCare@ihsmarkit.com
Americas: +1 800 IHS CARE (+1 800 447 2273)
Europe, Middle East, and Africa: +44 (0) 1344 328 300
Asia and the Pacific Rim: +604 291 3600

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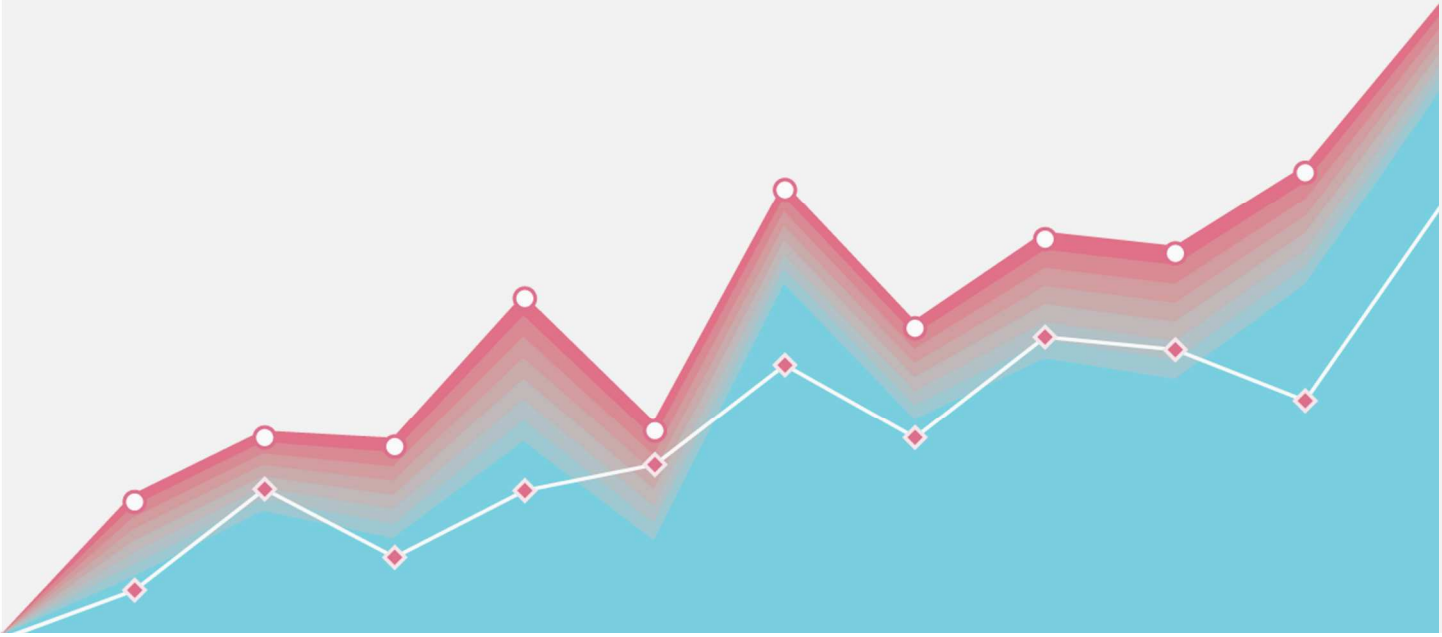
Attachment 3: PA Consulting Group, "The Contribution of the Coal Fleet to America's Electricity Grid"

THE CONTRIBUTION OF THE COAL FLEET TO AMERICA'S ELECTRICITY GRID

Prepared for the American Coalition for Clean Coal Electricity

August 2017



PA Regional Office:
PA Consulting Group
1700 Lincoln Street
Suite 1550
Denver, CO 80203
USA
Tel: +1 720 566 9920
Fax: +1 720 566 9680
www.paconsulting.com

Version no: 1.0

Prepared by: PA Consulting Group, Inc.

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EXECUTIVE SUMMARY

The U.S. electricity grid is rapidly evolving due to the low-cost supply of natural gas and the increasing penetration of grid-scale and behind-the-meter intermittent renewable generation. Innovation and cost reductions in battery storage and other technologies mean that this pace of change is likely to continue. These changes have sparked a debate over the need for what have historically been referred to as "baseload" electricity generation resources, such as coal-fueled and nuclear power plants. These resources have traditionally operated around-the-clock, continually providing reliable electricity generation at a stable price, as well as contributing to overall grid resilience. As explained in this report, these traditional resources—including coal-fueled generation—provide attributes that will remain critical to the grid as it continues to evolve.

There is broad agreement that the electricity system should be reliable and resilient, and that electricity prices should be affordable. A reliable electric system minimizes the likelihood of disruptive electricity outages, while a resilient system acknowledges that outages will occur, prepares to deal with them, and is able to restore service quickly. In pursuing these commonly-held goals, policy makers, utility executives, and grid operators are required to make decisions that take into consideration both near-term and longer-term economic, policy and technology trends. These decisions ultimately lead to a determination of the most appropriate mix of electricity resources that reflect the diversity of the U.S. electric grid (e.g., different market structures, physical features, and policy preferences).

This report highlights three ways in which the United States' existing coal fleet benefits the electricity system:

Coal-fueled generation provides many attributes that are critical for grid reliability and resilience. A variety of attributes are required to maintain a reliable and resilient grid, and no one technology can do it all. Different resources provide these attributes to varying degrees, and coal provides many critical attributes. As the electric sector becomes increasingly reliant on natural gas and as renewable penetration grows, market structure changes may be required to properly price and value the contribution of all types of generation to ensuring both reliability and resilience.

Resource diversity is critical in maintaining a reliable and resilient electricity system. The coal fleet plays an important role in helping to maintain resource diversity. The impact of unpredictable low-probability, high-impact events that challenge grid resilience is magnified as the electricity system evolves. For example, natural gas has historically been prone to supply disruptions and price shocks, while intermittent renewable and demand response resources are generally not dispatchable[1] to meet unforeseen fluctuations in electricity demand. The U.S. coal fleet benefits from stable commodity pricing, multiple means of delivery, and an ability to stockpile fuel. Diversity in fuel supply improves the resilience of the grid and mitigates the impact of fuel supply disruptions.

The coal fleet provides stable pricing as a hedge against natural gas price volatility. The price of natural gas has an outsized impact on the price of electricity in most markets. Today's natural gas prices are at near-historic lows, which has resulted in natural gas-fired combined-cycle plants being *the* favored technology to replace retiring generation and meet expected load growth.

[1] Dispatchable generation can be scheduled ahead of time, and adjust power output by command (within physical time constraints).

Retaining existing coal-fueled power plants can help insulate ratepayers against rising and possibly volatile natural gas prices.

The essential attributes provided by different resources to grid reliability, resilience and affordability are shown in Table ES-1 below. Each attribute is described in Section 1.1. The table is not intended to demonstrate which resource is "better," or to rank the resources. However, the comparison highlights two important facts: (i) all the attributes listed are needed for grid reliability and resilience; and (ii) no single resource by itself exhibits all the attributes needed for reliability and resilience—however, coal-fueled generation provides many of these attributes. Note that the table is not intended to be a complete list of either resource types or attributes, but it illustrates the most common electricity resources.

Table ES-1: Qualitative Comparison of Grid Reliability and Resilience Attributes by Fuel Type[2]

Attribute	Coal	Natural Gas	Wind/Solar	Nuclear	Demand Response
Dispatchability	✓	✓		✓	
Inertia	✓	✓	✓(wind)	✓	
Frequency Response	✓	✓	✓[3]		
Contingency Reserves	✓	✓			✓
Reactive Power	✓	✓		✓	
Ramp Capability	✓	✓			✓
Black Start		✓			
Resource Availability	✓	✓		✓	
On-Site Fuel Supply	✓			✓	✓
Reduced Exposure to Single Point of Disruption	✓		✓	✓	✓
Price Stability	✓		✓	✓	✓

Regulators and policy makers should recognize and appropriately value the attributes of each electricity resource and fuel type, including coal-fueled generation, to maintaining grid reliability, resilience and affordability.

[2] Source: PA Consulting Group analysis.

[3] Although most wind does not provide frequency response, newer vintage wind resources with integrated storage can do so. Some solar depending on the type of inverter also supports frequency response.

CONTENTS

1 A DIVERSE MIX OF GENERATION RESOURCES IS IMPORTANT FOR GRID RELIABILITY

In recent years, many industry participants have qualitatively and quantitatively evaluated the benefits of different generation technologies and fuel sources. These findings can be controversial and require the appropriate context and framing. For example, a single type of power generating resource that meets "all" the identified attributes of a resilient and reliable resource cannot alone meet all of the grid's generation needs, since there are system-wide resiliency risks associated with relying on any one technology or fuel type. Such findings tend also to focus on the contributions of various technologies to normal grid operations, while discounting an uncertain future that will invariably feature low-probability, high-impact events (such as the Polar Vortex winter event that occurred in 2014). Planning for a grid that is both reliable and resilient requires a focus on such unlikely events.

This section begins with a discussion of attributes of different types of generation to set the context of how baseload generation (including coal) fits into the current mix of U.S. generation technologies that collectively contribute to a reliable grid and low-cost electricity. It then frames the discussion in the broader context of the regional variations in market structures and policies that shape generation mixes. Chapter 2 will discuss how baseload generation contributes to resilience.

1.1 The attributes of a resilient and reliable electricity grid

A resilient and reliable electricity grid is good for the United States. However, translating this truism into an understanding of the roles different power generation technologies serve within the appropriate fuel mix, including coal, is more challenging. For example, the Brattle Group recently wrote a report suggesting that baseload generation is no longer needed.[4] Such views may oversimplify the complexity and heterogeneity of the modern grid.

Collectively, the mix of generation on the grid needs to provide the following attributes, at a minimum, in order to satisfy the goals of a reliable, resilient and affordable electricity system:

Dispatchability. The operation of baseload power plants can be scheduled well in advance to meet predicted load, with minimal need to forecast factors which affect many other generation technologies. Over shorter time-frames, baseload power can be adjusted to increase or decrease output as necessary, providing flexibility in meeting fluctuations in demand.

Frequency response provides active control to maintain a constant 60 Hz—this is the frequency that must be maintained to keep the grid, and all connected equipment, operating safely and reliably. This can only be provided through active generating resources and fast response storage, which must respond to moment-to-moment dispatch instructions to maintain the grid's frequency. Baseload plants with Automatic Generation Control ("AGC") can provide frequency regulation in all hours of the day, including in overnight hours when wind penetration is typically the greatest. Frequency regulation requirements are increasing in parts of the country where there is significant

[4] Advancing Past "Baseload" to a Flexible Grid, The Brattle Group, June 26, 2017

renewable penetration, as the intermittency of renewables requires frequency adjustment more often.

Inertia. By their nature, baseload power plants consist of large electric machines rotating at a frequency of 60 Hz. As the load on the grid increases, the rotation of connected machines begins to slow down, reducing the grid frequency; alternatively, a reduction in load causes faster rotation and an increase in frequency. However, when such load changes occur rapidly in a system with baseload power, the inertia provided by these heavy rotating machines resists the changes in frequency, helping the grid ride through disturbances. Additionally, the short time frame of this inertial response buys time for other grid control systems to take action to address the root cause of such disturbances.

Contingency reserves. Baseload plants are able to provide spinning reserves to provide backup power in case of system disruptions (e.g., a generator tripping offline) at short notice (often ten to thirty minutes). This is accomplished by holding back capacity from the energy market, without the risks associated with starting up from a cold state or a fuel supply disruption. Offline reserves are typically provided by fast-starting peaking plants.

Reactive power. Changing characteristics of load and generation on the grid—even when supplying constant power—can result in fluctuations in the voltage level, which may damage electric loads, generators, or transmission and distribution equipment. Baseload generators can supply reactive power to counteract these fluctuations both on command and through AGC.

Ramp capability. Resources which can quickly increase or decrease their power output—"ramping" up or down—are needed on the grid in order to quickly adjust to system shocks such as momentary increases or decreases in renewable energy output, load spikes, or generator outages elsewhere on the system. Ramp capability is one of the most critical requirements for grid flexibility.

Black start capability. Several types of generators require an active electric connection in order to supply power to the grid, and will disconnect whenever the grid fails or moves outside of set operating limits. After such a failure or a blackout, generators with "black start" capability are necessary to re-start the grid and give other generators a signal to synchronize to. These resources typically include hydro-electric, diesel generators, and combustion turbines.

Resource availability. Generators need to be available to provide a relatively constant supply of electricity when it is needed under a variety of system conditions, seasons, and times of day. Wind and solar resources are by their nature intermittent, while many demand response resources are seasonal. Conversely, coal, natural gas and nuclear generators can run uninterrupted for very long periods of time.

On-site fuel supply. Resources with on-site fuel supply contribute to grid resilience by minimizing the potential for fuel supply disruptions. Natural gas supplies for generating plants are generally scheduled on a daily basis ("just in time"), with almost no opportunity for on-site storage. This leaves them vulnerable to upstream supply issues, whether from pipeline constraints or from supply failures (some are capable of burning oil to insulate against this risk), while hydroelectric generation may have limited "fuel" availability due to reservoir limitations or other natural constraints. During periods when the electricity system is stressed, on-site fuel supply contributes to increased grid resilience.

Reduced exposure to single point of disruption. Many grid resources rely on external systems to ensure they operate reliably. For example, natural gas generators require a constant external fuel supply that is be supplied only by a network of pipelines, compressor stations, storage, and LNG

facilities. Resources utilizing “free” fuel supplies, such as the wind and the sun, have reduced exposure to external factors, as do the majority of coal-fueled generating stations, which maintain on-site fuel stockpiles and have multiple means of fuel delivery as a resource class.

Stable, predictable pricing. Generators with stable pricing can be freely dispatched by system operators without the risk of incurring high costs for customers, or operating losses for generators. Because marginal costs are based on variable costs, which largely reflect fuel costs, resources with volatile fuel costs like natural gas can result in unstable power prices. Baseload generation has traditionally had relatively high fixed costs, but low and predictable variable costs.

1.2 The role of baseload generation in supporting grid reliability

Baseload generation typically refers to low-variable cost resources that operate around-the-clock to meet minimum system demand. By its nature, baseload power provides resilience and long-term affordability, while its rotational inertia contributes to ancillary services that ensure essential reliability services, such as frequency control, contingency (spinning) reserves, and reactive power. Arguments that baseload generation is an artifact of traditional resource planning miss two key realities about the current electricity system and the continued relevance of baseload resources within it.

First, while the growth in renewables in some markets drives a need for ramping ability, those attributes provided by baseload generation remain critical to the reliable, resilient and affordable operation of the grid, and in some ways are magnified by the growth in renewables. Second, the pace of change of the electric grid across the United States has not been uniform, and the need for retaining baseload power reflects the various market structures and regional variation in existing generating resources. In short, there is not a one-size-fits-all answer.

Wholesale electricity markets are slowly recognizing that a greater need to value baseload resources for these attributes may be appropriate. For example, PJM is currently considering several reforms to improve price formation and reduce the "pernicious effect" of issues such as negative pricing. PJM states that this need is critical because the distorting price signals "erod[e] revenue streams… of thermal generation, whose continuing operation is needed to meet capacity requirements and provide reliability services to accommodate for the intermittency of renewable generation".[5]

1.3 The lack of market uniformity

The importance of the benefits provided by baseload coal is further highlighted by differences in regional market structures. In the excitement over new technologies and visions for how the future may unfold, it is easy to forget that the grid is not a uniform system. In some regions there have been rapid advances in the integration of new generation technologies, which has spurred new challenges for system operators. In other regions with limited renewable resources, the challenges are largely unchanged from a generation ago. Due to these regional distinctions, solutions that work for one part of the country may not work for another. The two key ways in which regions differ are: (i) current electricity market structures; and (ii) existing regional generation supply. While not the only factors, these two critical factors are often overlooked in the debate regarding the role of existing coal-fueled plants. Policy prescriptions should therefore appropriately reflect the needs and goals of individual regions.

Different market structures

For most of the last century, the U.S. electricity grid was dominated by vertically-integrated utilities that controlled the majority of the electricity value chain, from the generation of electricity at power plants to its

[5] PJM White Paper, "Energy Price Formation and Valuing Flexibility", June 15, 2017. Available at: http://www.pjm.com/~/media/library/reports-notices/special-reports/20170615-energy-market-price-formation.ashx

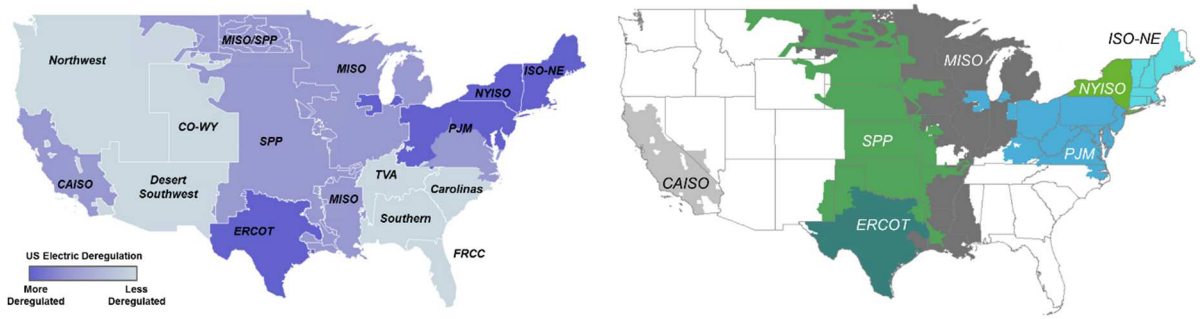
delivery to homes and businesses. These state-regulated monopolies and public power entities were viewed as the most effective way to safely provide affordable and reliable electricity to the public.

However, the paradigm shifted in the mid-1990s and early-2000s, as electric market deregulation swept across the United States. At its core, deregulation was intended to increase competition in the electric sector and thereby lower costs for customers. However, the issue of whether an unfettered competitive market will adequately address policy and reliability goals without regulatory guidance is debatable, along with whether the markets provide appropriate compensation to achieve desired levels of reliability and resilience.

Electric deregulation has progressed differently across the United States, with states in the Northeast, Mid-Atlantic, and Texas generally being the most deregulated, and states in the Southeast and much of the Midwest and West generally being less deregulated. Some regions of the country have evolved further, forming Independent System Operators ("ISOs") or Regional Transmission Operators ("RTOs") (see Figure 1-1), such as PJM, New England, and New York. These regions have created independent oversight of the wholesale markets, and feature more competitive markets when compared with regions such as the Southeast and most of the West (excluding California). In these competitive markets, locational market pricing ("LMP") prices reflect energy, transmission congestion and losses every five minutes at thousands of separate locations on the grid, which accurately inform dispatch signals that reflect least-cost outcomes.

Figure 1-1: United States Deregulation and Electricity Markets[6]

Level of Deregulation **Major U.S. Electricity Markets**



Today, over half of U.S. states have adopted some form of electric deregulation, with much of the competition occurring within seven distinct electricity markets. In these markets, power plants owned by competitive generators are expected to enter (or exit) the market based on their ability to earn (or fail to earn) a profit. This dynamic shifts the risk associated with changing market forces from the captive electricity customer to the power plant investor.

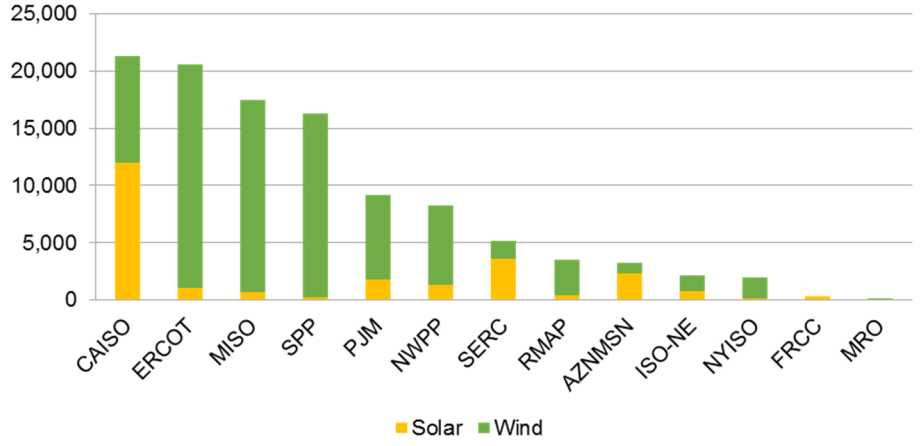
However, outside of these electricity markets (and to some extent within them), vertically integrated utilities under state regulatory control exist. Where such utilities are the norm, changes to market dynamics that impact the cost of electric generation are generally borne directly by the electric customer. As such, vertically integrated utilities and the regulatory bodies governing them typically focus on long-term planning, and carefully weigh how altering the power generation supply may impact customers over the long-term. This includes weighing the financial implications to the customer of prematurely retiring existing generation that provides a natural hedge against future reliability, resilience, and market risks.

[6] Source: ABB's Energy Velocity suite.

Regional variation in generation supply

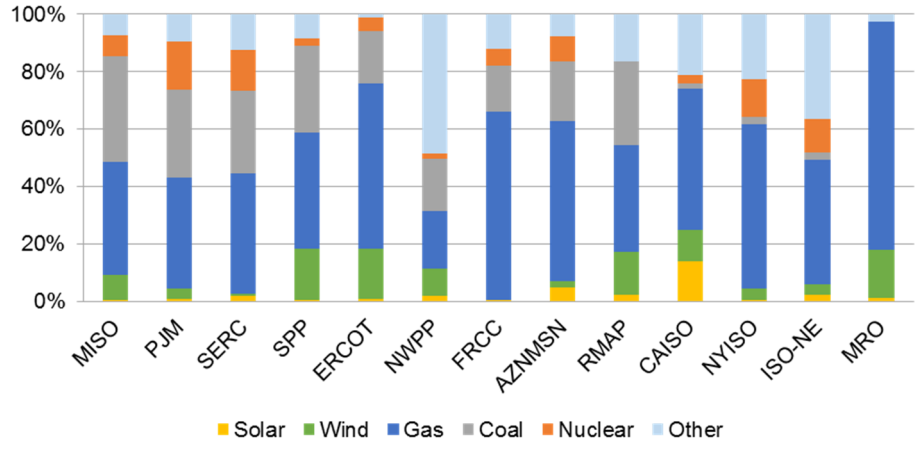
The growth of new energy technologies has not occurred uniformly across the United States. In regions where there has been more adoption of renewables, markets have evolved to accommodate these changes in the resource mix. While this market evolution is necessary in places like California, not all states will reach (or have the potential to reach) high levels of wind and solar penetration as quickly. The uneven geographic distribution of growth in wind and solar capacity (illustrated in Figure1-2) has two principal drivers. The first is state-level policies, including specific renewable energy targets, which have subsidized these resources and disproportionately encouraged growth in certain states. The second is the differing quality and availability of solar and wind resources across the United States.

Figure 1-2. Installed Solar and Wind Capacity (MW) by Electricity Region[7]



Moreover, even in regions that have relatively high intermittent renewable penetration, such as in the ERCOT electricity market of Texas, these newer resources still make up a small component of the overall existing fuel mix (see Figure 1-3).

Figure 1-3. Installed Capacity (% of Nameplate MW) by Electricity Region[8]



[7] Source: SNL Energy.

[8] "Other" includes oil, hydro-electric, biomass, and waste-to-energy. Source: SNL Energy.

1.4 The role of coal-fueled generation

Renewable energy has in recent years become an important part of most grids in the United States. Its role has grown in response to state policies, consumer preferences and declining costs. However, intermittent renewable energy by itself cannot create a reliable and resilient power grid, since system operators require dispatchable generation to meet load and provide the aforementioned attributes critical to maintaining the grid. This need highlights a central challenge of wind and solar generation. When the sun does not shine and the wind does not blow, these renewable technologies are unable to provide electricity to the grid. This intermittency is not just limited to predictable factors, such as the rising and setting of the sun, or seasonal variability; there are also localized challenges associated with passing clouds and storm systems that can prevent expected generation from materializing during the day.

To reliably integrate renewables—particularly at high penetrations—regions with significant renewable capacity will increasingly need generation resources providing flexibility attributes which fast ramping natural gas-fired generation supply. Regions that currently have significant existing coal-fueled generation within the fuel mix (especially those with limited levels of renewable generation) do not currently have the same need for flexibility as those with significant amounts of intermittent generation. In such areas, low-marginal cost thermal resources such as coal-fueled generation play an important role in maintaining an affordable, reliable, and resilient electricity grid through the operational and electrical attributes which they provide. Furthermore, even in markets where the need for flexibility is heightened, the attributes provided by baseload resources are still relevant (and in the case of frequency response magnified). Care must be taken to ensure that they are adequately valued.

2 THE IMPORTANCE OF GRID RESILIENCE

Electricity system planners evaluate both reliability and resilience in designing and operating the grid. This helps ensure safety (by maintaining access to critical infrastructure and services), a favorable business and investment climate, and a desirable quality of life. Unlike reliability, which seeks to minimize the likelihood of disruptive outages on the system, "*a resilient system is one that acknowledges that such outages can occur, prepares to deal with them, minimizes their impact when they occur, is able to restore service quickly, and draws lessons from the experience to improve performance in the future.*"[9]

Electricity is still difficult and costly to store in most circumstances. As a result, the grid is operated in real-time and requires constant management and adjustment of system operations to ensure this reliable supply. Furthermore, the electric system operates in an environment where equipment failures, extreme weather, natural disasters, malicious attacks, and other events can occur suddenly and unexpectedly. These types of low-probability, high-impact events can significantly compromise reliability and can lead to fuel supply disruptions for electric generators. As such, ensuring fuel diversity is critical to maintaining the resilience of the electricity system.

While natural gas is an efficient fuel that allows for fast-ramping generation, the complex nature of the natural gas production, transmission, and distribution system, "just-in-time" delivery, relatively limited storage capability, and competing high-priority end uses make natural gas-fired generators more prone to supply disruptions. Renewable energy contributes towards fuel diversity and resilience, but due to its intermittent nature, it must often be balanced with thermal (coal, natural gas, and nuclear) generation in order to ensure that load is reliably served. Because of its unique characteristics, including on-site fuel stores and multiple modes of transportation, existing coal-fueled generation has an important role to play in maintaining fuel diversity, reliability, and resilience of the grid.

2.1 The focus on grid resilience

Ensuring grid resilience goes beyond the traditional view of power system reliability. It encapsulates how the power grid as a system will react to large-scale catastrophic events including natural disasters, malicious attacks, and large-scale system failures. With concern about how the grid is changing in an age when new types of threats to the grid are being recognized, NERC and the RTOs/ISOs are paying increased attention to resilience. For example, PJM in its "Grid 20/20" series of stakeholder meetings for 2017 has been examining resilience in terms of fuel mix, diversity of resources, and security.[10] In PJM's recent study examining its evolving resource mix, the grid operator identified fuel risk, fuel assurance, and frequency response as potential issues if natural gas and renewables replace coal in the current generation portfolio mix.[11] Similarly, NERC looks at resilience from a number of perspectives, including single points of disruption and the risks of dependence primarily on natural gas-fired generation.[12]

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[9] Source: The National Academy of Sciences, Engineering, and Medicine, Enhancing the Resilience of the Nation's Electricity System (prepublication copy), 2017, p. 1-6.

[10] "Grid 20/20: Focus on Resilience (Fuel Mix Diversity & Security)." PJM, April 19, 2017.

[11] PJM looked at a number of alternative scenarios including where 25%, 50%, 75%, and 100% of the existing coal fleet is retired. *PJM's Evolving Resource Mix and System Reliability*, PJM Interconnection, March 30, 2017.

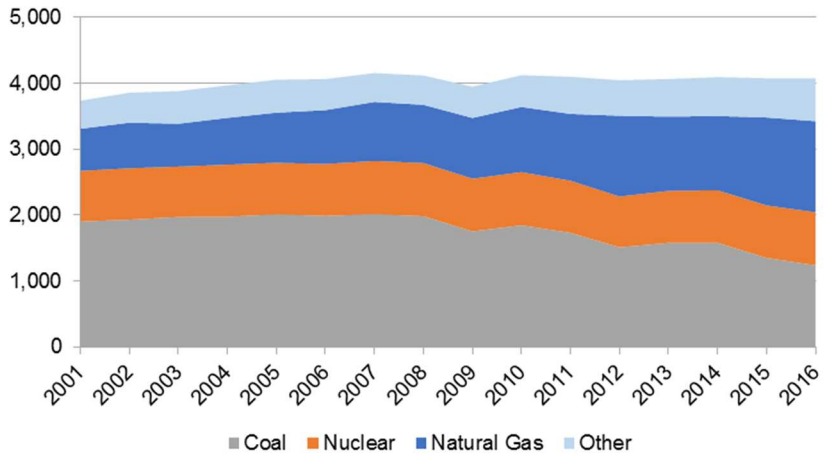
[12] *State of Reliability 2017*, North American Electric Reliability Corporation, June 2017.

2.2 Fuel mix and diversity of resources contributes to resilience

It is not possible to protect the electric system against every possible disruption, and outages are bound to occur. This feature is noted by the National Academy of Sciences, who state that "*While utilities work hard to prevent large-scale outages, and to lessen their extent and duration, such outages do occur and cannot be eliminated.*"[13] Because of the inevitability of low-probability, high-impact events, electric system planners increasingly seek resilience alongside reliability.

Two components that contribute to electric system resilience are: (i) diversification of the fuels used, and (ii) ensuring adequate and consistent fuel supply to electric generators. The fuel supply mix has shifted over the past fifteen years. Coal and nuclear generation today provide approximately half of total utility-scale electricity generation (down from 72% in 2001), while natural gas-fired generation has risen to nearly 34% (up from 17% in 2001). From 2001 to 2016, natural gas-fired generation grew from 639 TWh to 1,380 TWh, a 116% increase, while total electricity generation grew by only 9%.[14] See Figure 2-1.

Figure 2-1. U.S. Electricity Generation by Fuel Type, 2001-2016 (TWh)[15]



There is no single "perfect" fuel upon which to rely for a reliable and resilient electricity system. Rather, a diversity of fuels helps the system maintain reliability and quickly bounce back after low-probability, high-impact events by allowing operators to maximize the benefits of each individual fuel type while offsetting each fuel's drawbacks. As a fuel with unique reliability and resilience benefits, coal plays an important role in this diverse generation mix.

The electricity system is more resilient when generation is sourced from a variety of fuels and technologies. A common argument made in favor of state-level renewable portfolio standards ("RPS") is that these standards help ensure fuel diversity on the grid. For instance, the Council of State Governments has noted that one of the main objectives of state RPS is "*to diversify the state's electricity supply*,"[16] and most states allow a variety of renewable energy technologies (e.g., wind, solar, biomass,

[13] Source: The National Academy of Sciences, Engineering, and Medicine, Enhancing the Resilience of the Nation's Electricity System (prepublication copy), 2017, p. 1-3.

[14] Source: EIA, Electric Power Monthly, accessed July 27, 2017.

[15] Source: Ibid.

[16] Source: The Council of State Governments, Overview of State Renewable Portfolio Standards, December 2008.

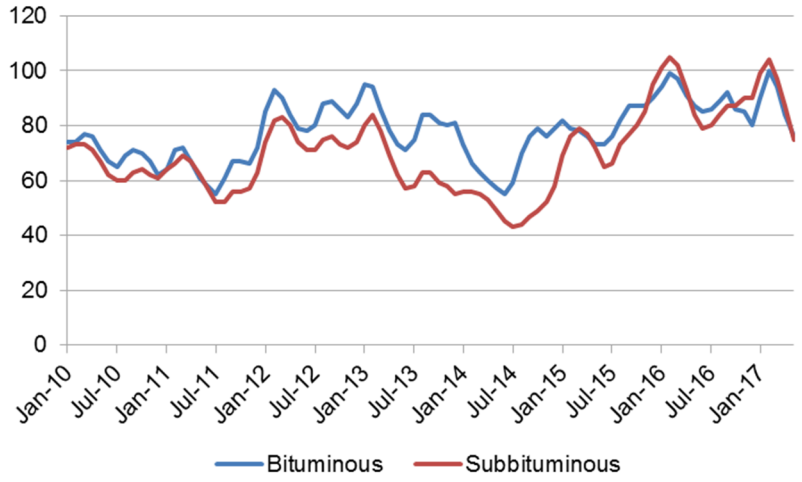
waste-to-energy, etc.) to qualify for renewable energy credits. This acknowledges that there is an inherent benefit to diversity, regardless of fuel supply. However, many of these renewable energy technologies are not dispatchable, meaning the electric system must have dispatchable generation to balance their intermittency. Dispatchable generation includes coal, natural gas, and, to some extent, nuclear and hydroelectric power. However, if the electric system has an over-reliance on dispatchable natural gas fired generation, it reduces diversification from a critical sub-class of generation that has unique reliability and resilience attributes compared to natural gas.

2.3 Coal-fueled generation contributes to system resilience with an on-site fuel supply

While coal-fueled plants are not free from outage risks, they have unique attributes that contribute to grid resilience, including a secure fuel supply. First, the vast majority of coal consumed in the United States is used for electricity generation (93% in 2016)[17] and does not compete with higher-priority uses. This practically eliminates the risk that coal deliveries to generators would need to be forcibly curtailed in order to serve other uses. In contrast, natural gas is also used for residential space heating, and flows on the same pipelines as natural gas provided to power generators.

Second, coal is an energy-dense solid that is relatively easy for generators to stockpile on site, mitigating exposure to supply disruptions. As of May 2017, a representative sample of coal-fueled plants had approximately 76 days and 75 days of bituminous and subbituminous coal stockpiled at their facilities, respectively. Over the last five years, coal-fueled plants had an average of approximately 82 days and 73 days of readily accessible bituminous and subbituminous coal stockpiled at their facilities.[18] See Figure 2-2. Because lignite coal is generally consumed at mine-mouth power plants (all but two lignite coal-fueled plants source their coal from mines within 30 miles of the plant),[19] it is also relatively insulated from supply shocks.

Figure 2-2. Days of Stockpiled Coal Burn[20]



[17] Source: EIA, Quarterly Coal Report, accessed July 27, 2017.

[18] Source: EIA, Electricity Monthly Update, accessed July 27, 2017.

[19] Source: ABB's Energy Velocity Suite.

[20] Source: EIA, Electricity Monthly Update, accessed July 27, 2017.

Furthermore, unlike natural gas, coal can be shipped through a variety of transportation methods, including rail, truck, and barge. In contrast, a disruption to a major natural gas pipeline or prolonged excessive demand that stresses pipeline infrastructure, particularly in regions with limited underground storage, could substantially reduce access to natural gas for an extended period of time. The diversity in transportation methods makes coal supply infrastructure as a whole far less vulnerable to single points of disruption than natural gas.

This is not meant to imply that natural gas is a poor fuel choice for electricity generation. Rather, it is meant to demonstrate that each fuel used to generate electricity has its own unique benefits and drawbacks, and ensuring a diverse mix of fuels creates a more reliable and resilient electricity system.

This dynamic has been noted frequently by system planners. For instance, NERC has stated that "*overdependence on a single fuel type increases the risk of common-mode or single-point-of-failure disruptions as experienced during recent extreme weather events…*"[21] and that "*maintaining fuel diversity provides inherent resilience to common-mode risk*."[22] Similarly, PJM has highlighted that "*resource diversity can be considered a system-wide hedging tool that helps ensure a steady, reliable supply of electricity*,"[23] and that "*PJM recognizes that the benefits of fuel mix diversity include the ability to withstand equipment design issues or common modes of failure in similar resource types, fuel price volatility, fuel supply disruptions, and other unforeseen system shocks*."[24] Furthermore, ISO-NE identifies specific fuels that are particularly helpful in maintaining reliability and resilience, stating that "*the lights stay on during extremely cold periods with a combination of these fuels: nuclear, coal, oil and LNG*."[25]

2.4 Gas-fired generation has limitations

Despite its status as a dispatchable fuel, natural gas supply is not as physically secure as other thermal generation fuels, particularly coal. Among generation technologies, natural gas is unique in that, similar to electricity, it relies on a complex production, transmission, and distribution network for just-in-time fuel delivery, often over long distances. This interconnected system of production wells and pipelines, while capable of smooth operation under normal circumstances, is exposed to disruptions during low-probability, high-impact events. For example, natural gas systems pose fuel supply risk from disruptions during earthquakes "*given the long supply chain and vulnerability of pipelines*."[26] Additionally, as natural gas and electric transmission and distribution systems are increasingly interdependent, natural gas compressor stations on gathering lines and along major pipelines are often vulnerable to electric system outages.[27]

While storage is possible, natural gas must be stored at high pressure to be volumetrically efficient, which is both physically challenging and costly at the small scale of individual generators. Instead, natural gas is

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[21] Source: NERC, Short-Term Special Assessment: Operational Risk Assessment with High Penetration of Natural Gas-Fired Generation, May 2016, p. v.

[22] Source: NERC, 2016 Long-Term Reliability Assessment, December 2016, p. 20.

[23] Source: PJM, PJM's Evolving Resource Mix and System Reliability, March 30, 2017, p. 3.

[24] Source: Ibid p. 6.

[25] Source: Gordon van Welie, ISO-NE, State of the Grid: 2017 (presentation), January 30, 2017, p. 19.

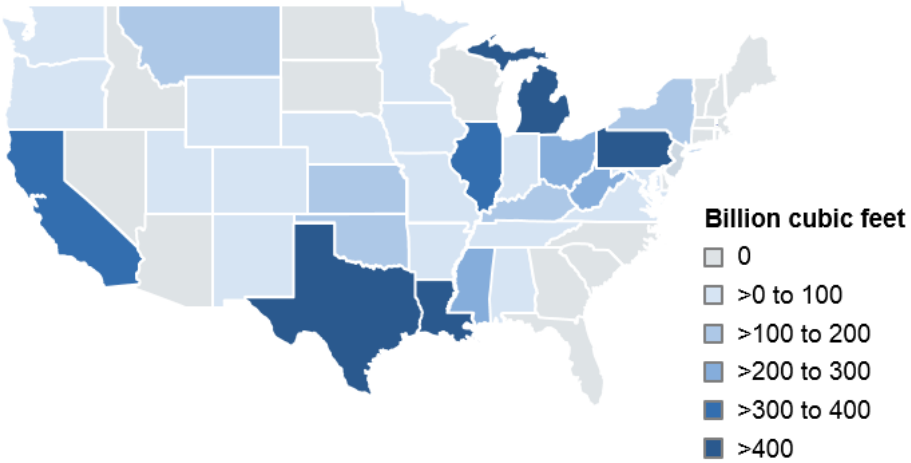
[26] Source: The National Academy of Sciences, Engineering, and Medicine, Enhancing the Resilience of the Nation's Electricity System (prepublication copy), 2017, p. 3-5.

[27] Source: Department of Energy, QER Report: Energy Transmission, Storage, and Distribution Infrastructure (Chapter 2), April 2015.

typically stored in large-scale, centralized underground storage facilities, which include depleted oil and natural gas fields, salt caverns, and aquifers. As of November 2016, the total demonstrated maximum working gas capacity of underground storage in the continental United States was 4,373 Bcf. This capacity is an important balancing mechanism for the natural gas market. Demand in the winter often exceeds daily production, while the opposite is true in the summer, so storage is typically built up in the summer in anticipation of winter use. In order to keep storage levels within an acceptable band that will provide security in the winter, seasonal prices move to encourage or discourage consumption from price-sensitive demand sources. However, this capacity is not designed to provide long-term natural gas reserves. In 2016, nearly 27,500 Bcf of natural gas was consumed in the United States, meaning that there is only about 60 days of natural gas supply in storage reserves, not accounting for geographic concentration and pipeline constraints that limit actual deliverability.

Additionally, because effective underground natural gas storage is dependent on favorable geology, it is highly concentrated in certain geographies. Notably, over 50% of the working gas storage capacity is located in just five states – Michigan, Texas, Louisiana, Pennsylvania, and California. Furthermore, 18 states in the continental United States have no material storage capability, including all of New England and four Atlantic coast states in the Southeast[28] (see Figure 2-3). This means that access to natural gas continues to rely on long-distance pipeline infrastructure, even to access stored gas.

Figure 2-3. Working Natural Gas Storage Design Capacity by State (November 2016)[29]



Furthermore, the demand for natural gas storage will likely increase in the future as the penetration of intermittent renewable generation increases. Natural gas firming generation which is used to respond to fluctuations in renewable energy supply, relies at least in part on stored gas, since it is difficult to ramp natural gas delivery quickly enough to fuel natural gas firming generators when additional output is called for. This places additional stress on physically limited stored natural gas supply, and increases the potential impact of risks such as rapid demand increases and large storage leak events. Furthermore, natural gas storage capacity is difficult to expand, due to factors like limited geology and challenging economics with recently low summer and winter gas price spreads.

[28] Source: EIA, Underground Natural Gas Working Storage Capacity, accessed July 27, 2017.

[29] Source: Ibid.

In addition to physical limitations, natural gas-fired generators face unique contractual and regulatory fuel supply restrictions. First, many generators directly interconnected with interstate and intrastate pipelines do not have firm gas supply arrangements, which are typically more costly than non-firm arrangements. Unlike firm arrangements, suppliers are not obligated to deliver natural gas under all circumstances under non-firm arrangements, including emergency events. This is particularly true in less regulated regions with competitive centralized wholesale markets, where electricity prices do not incorporate the benefits that are associated with more expensive firm transportation.

Second, some generators are not served directly by large pipelines, and instead receive gas service through a local distribution company ("LDC"). Because LDCs also serve other, higher-priority end uses such as residential heating, they hold the right to interrupt gas supply to electric generators if needed.

Although direct information on the amount of natural gas-fired generation capacity that has firm versus interruptible gas supply arrangements is not publicly available, nor the amount that is supplied through LDCs, it is clear that the amount of natural gas delivered on an interruptible basis is significant in several less-regulated markets. For example, in ISO-NE, MISO, NYISO, and PJM, PA estimates that at least 30% of the natural gas delivered to power plants in 2016 from pipelines was delivered on an interruptible basis.[30] PA further estimates that, nationwide, 10-20% of gas-fired generators receive service through an LDC.[31]

Third, the Natural Gas Policy Act of 1978[32] authorizes the Department of Energy to direct the allocation of natural gas supplies by interstate pipelines and LDCs to "*high-priority users*" if the President declares a natural gas emergency. High-priority users under the Act specifically include residential customers, smaller commercial establishments, and buildings with critical operations, like schools and hospitals. Therefore, due to the lack of firm supply agreements and the potential curtailment of natural gas deliveries to generators ahead of high-priority users during emergency events, natural gas-fired generators face certain supply risks that may prevent them from operating during certain low-probability, high-impact events.

While low-probability, high-impact events on the electric system are bound to occur, fuel diversity can improve the reliability and resilience of the grid, and coal-fueled generation has several unique attributes that contribute to reliability and resiliency. Coal-fueled generation does not compete for fuel supply with other demand, unlike natural gas generation which often faces fuel supply curtailment risk due to competition with higher-priority demand and the lack of firm supply arrangements. Coal is also easy to stockpile on-site in quantities large enough to ensure that coal-fueled plants can continue operating for several months even in the event of a supply disruption.

On the other hand, natural gas is difficult to store except in large, geologically appropriate underground storage facilities that remain vulnerable to critical failures. Additionally, gas from storage facilities still must be transported to natural gas generators, often over long distances, and is vulnerable to the same contractual and physical disruptions that are discussed above. Coal can also be transported through several means, while natural gas relies on just-in-time delivery through a complex web of production wells,

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[30] More specifically, PA estimates that the percentage of gas delivered to power plants on firm transportation arrangements in 2016 was approximately 35-45% for ISO-NE, 45-55% for MISO, 35-45% for NYISO, and 60-70% for PJM. PA's analysis of firm versus interruptible gas supply is based on a review of EIA Form 923 data for natural gas-fired generators, and the U.S. Environmental Protection Agency's Emissions & Generation Resource Integrated Database ("eGRID").

[31] PA's analysis of LDC gas delivery is based on a review of EIA Form 860 data for natural gas-fired generators.

[32] Public Law 95-621, 95th Congress, Natural Gas Policy Act of 1978, November 9, 1978.

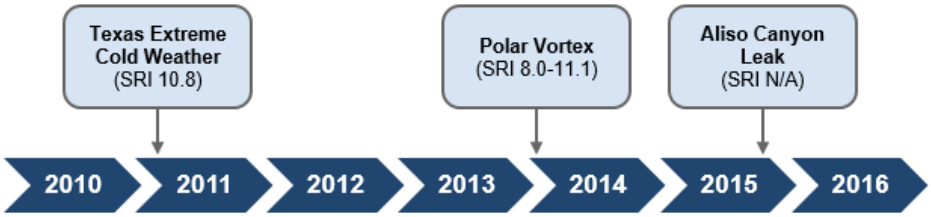
transmission, and distribution lines. These unique characteristics make coal-fueled generation critical to the continued reliability and resilience of the electric system.

2.5 The recent instances of low-probability, high-impact events

Low-probability, high-impact events on the electric system have occurred recently with notable frequency, despite their unpredictability. The North American Electric Reliability Corporation ("NERC"), the primary authority responsible for monitoring and enforcing electricity reliability on the U.S. system, calculates a daily Severity Risk Index ("SRI") to measure the reliability performance of the bulk power system. The SRI includes generation, transmission, and load loss components, and accounts for unplanned generation outages, high-voltage transmission system outages, and load lost on the distribution system as a result of upstream events. In its most recent *State of Reliability* report, NERC notes that days with a SRI rating that exceeds 5.0 "*are often memorable and may provide lessons learned opportunities*."[33]

From 2010 to 2016, there were two outage events driven at least partially by generator fuel supply issues in which the SRI rating equaled or exceeded 5.0, indicating widespread and sustained generator outages and/or loss of load. There was one additional event that did not lead to immediate outages, but was noted by NERC as creating substantial future reliability risks due to fuel supply constraints[34] (see Figure 2-4).

Figure 2-4. Timeline of Memorable Fuel Supply Constraint Events[35]



Texas extreme cold weather event

The first memorable event since 2010 was an extreme cold front that hit the Southwest United States during the first week of February 2011. Temperatures remained below freezing for several days across the region, causing a large number of generators to trip offline, suffer significant output declines, or fail to start. The ERCOT region in Texas was most heavily affected, where 193 generating plants either failed or had significant declines in output. Combined with scheduled outages, this led to the unavailability of approximately one-third of the total ERCOT fleet.

In their report on this cold weather event, FERC and NERC noted that electric and natural gas interdependency contributed to the outages. Freezing temperatures, along with rolling blackouts caused by the initial wave of generator outages (which were driven largely by weather-related issues like equipment failures), drove substantial production declines at natural gas wells throughout the region. FERC and NERC determined that natural gas supply shortfalls contributed to approximately 1.3 GW of generator outages and derates in ERCOT.[36] For comparison, this was approximately half of ERCOT's spinning reserve requirement.

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[33] Source: NERC, State of Reliability 2017, June 2017, p. 13.

[34] Note that there were 10 total days in which SRI met or exceeded 5.0 from 2010 to 2016, but two of these days were associated with the same event as another memorable SRI day (the Polar Vortex and Superstorm Sandy).

[35] Source: NERC, State of Reliability 2017, June 2017; NERC, State of Reliability 2015, May 2015.

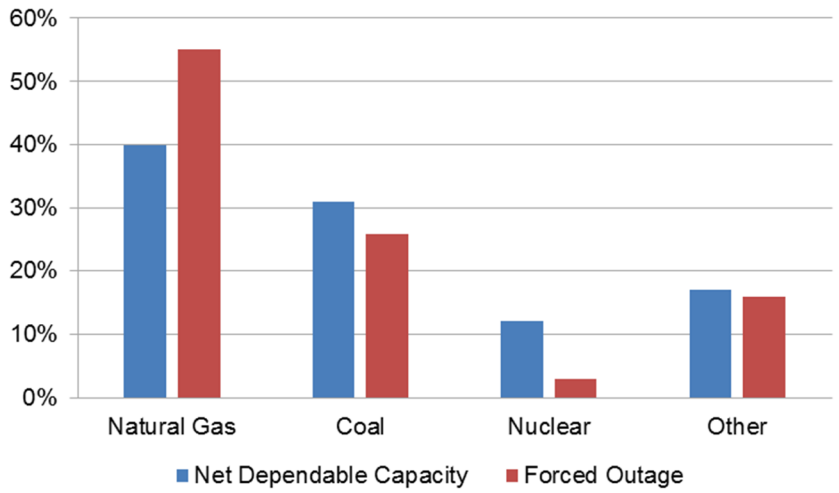
[36] Source: FERC and NERC, Report on Outages and Curtailments during the Southwest Cold Weather Event of February 1-5, 2011, August 2011.

The Polar Vortex

The second low-probability, high-impact event that caused fuel supply issues for electric generators since 2010 was the Polar Vortex, which caused sustained, extremely cold temperatures across the East Coast, Midwest, and South Central regions of the United States in early January 2014. These extremely cold temperatures increased demand for natural gas for both space heating and electricity. This strained gas transmission and distribution infrastructure in regions that relied heavily on gas for power generation. Due to the lack of firm gas supply agreements at many generators, and LDC and pipeline responsibility to serve heating demand before power generation, natural gas supply for a substantial share of generators was curtailed or interrupted.

Across affected regions, generator forced outages caused by interruptions to fuel supply totaled over 19 GW, largely comprised of natural gas supply disruptions.[37] Across the Eastern and ERCOT interconnections, natural gas-fired generation comprised 55% of forced outages. Coal and nuclear, on the other hand, represented only 26% and 3% of forced outages, respectively.[38] See Figure 2-5. On this dynamic, NERC noted that, "One of the largest issues impacting gas-fired generation was the curtailment or interruption of fuel supply."[39]

Figure 2-5. Polar Vortex Net Dependable Capacity vs. Forced Outage Percentage[40]



Aliso Canyon leak

Although not reflected in NERC's SRI metric, as it did not lead to an immediate generation outage, another low-probability, high-impact event with implications for the electric power system was the failure of the Aliso Canyon natural gas storage facility in Southern California in October 2015. Aliso Canyon is one of the largest gas storage facilities in the country, and was an essential supplier to nearly 10 GW of natural gas-fired generating capacity in the Los Angeles basin. However, a leak that occurred from

[37] While not simultaneous across regions, fuel supply interruptions during the Polar Vortex impacted 820 MW in MRO, 3,296 MW in NPCC, 10,700 MW in RF, 2,050 MW in SERC, 150 MW in SPP, and 2,309 MW in TRE.

[38] Source: NERC, Polar Vortex Review, September 2014.

[39] Source: Ibid, p. 2.

[40] Source: Ibid.

October 2015 through February 2016 led to the loss of over 70 Bcf (more than 80%) of its gas storage capacity.[41] California energy regulators placed an extended moratorium on new injections into the facility, a moratorium which was only recently lifted in July 2017, and only partially. In a risk assessment of high penetrations of natural-gas fired generation across several electricity regions, NERC noted that this shortage of gas storage capacity presented a significant electricity system reliability risk in the summer of 2016.[42]

It is also important to note that the leak at Aliso Canyon is not the only memorable natural gas storage leak in recent memory, and that significant natural gas storage infrastructure remains at risk of failure. In January 2001, a leak at the Yaggy underground natural gas storage field in Kansas caused multiple explosions resulting in two deaths and caused the loss of approximately 143 MMcf of gas. In August 2004, a wellhead fire and explosion at the Moss Bluff storage facility in Texas caused the release of approximately 6 Bcf of gas. Furthermore, additional natural gas storage facilities potentially remain at risk of leaks or other single points of failure. In its report on *Ensuring Safe and Reliable Underground Natural Gas Storage,* the U.S. Department of Energy noted that *"about 80% of natural gas storage wells with known completion years were drilled before 1980, and many predate modern materials and technology standards. These wells have been subject to environmental processes and mechanical stresses from injection and withdrawal of natural gas across multiple decades."*[43]

[41] Source: NERC, State of Reliability 2017, June 2017.

[42] Source: NERC, Short-Term Special Assessment: Operational Risk Assessment with High Penetration of Natural Gas-Fired Generation, May 2016.

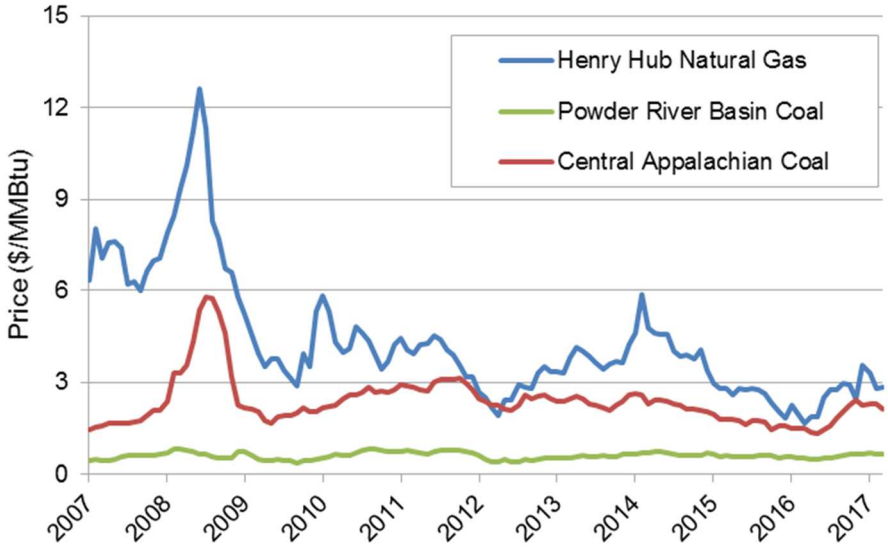
[43] Source: U.S. Department of Energy, Ensuring Safe and Reliable Underground Natural Gas Storage: Final Report of the Interagency Task Force on Natural Gas Storage Safety, October 2016, p. 54.

3 EXISTING COAL-FUELED GENERATION PROVIDES A HEDGE AGAINST POTENTIAL NATURAL GAS PRICE INCREASES

Seventy-seven gigawatts of natural gas-fired power plants have been built since 2009. While the decision to build these new plants is partially driven by load growth, it is predominantly driven by capacity retirements. Expanding supplies of low-cost shale natural gas mean natural gas-fired plants are currently the favored replacement form of capacity. While this boom provides near-term benefits, retaining coal resources provides an insurance policy against unforeseen volatility and increases in natural gas prices.

The current investment boom in natural gas-fired plants is driven in part by an expectation of continued low natural gas prices of approximately $3-4/MMBtu. Historically, however, natural gas prices have been volatile and subject to system shocks due to both market forces and extreme weather. Over the last decade, monthly average prices have repeatedly seesawed between approximately $3/MMBtu to above $12 (see Figure 3-1). During the Polar Vortex, prices at times reached $100/MMBtu in some markets. Preserving operating coal-fueled plants creates an insurance policy against the impacts of volatile natural gas prices.

Figure 3-1: Natural Gas and Coal Commodity Prices, 2007-2017 ($/MMBtu)[44]



[44] Source: ABB's Energy Velocity Suite.

3.1 An over-focus on short-term price signals

In electricity markets, the energy price typically reflects the marginal cost of producing power, which for thermal plants mostly reflects fuel costs. Natural gas-fired plants are cycled to meet intermediate and peaking load needs, such as in response to moment-by-moment changes in demand or supply (for example, to respond to forced outages or balance intermittent renewable generation). These fuel costs often make natural gas-fired plants the "marginal unit" in a market, providing the last incremental megawatt of power and setting the price paid for electricity in the wholesale market. Therefore, throughout the United States, the power price is closely linked to the price of natural gas.

Long-term investment decisions, however, reflect the total cost, rather than the marginal cost, of operating a power plant. The total costs include recovering fixed operating costs that are incurred regardless of whether a plant runs (for example, keeping a plant staffed) and a return on invested capital. When energy prices rise above the marginal cost of a power plant, these additional revenues provide them with a means to recover their fixed costs. However, price signals from the energy markets alone are generally not sufficient for full cost recovery because of market distortions.

For example, when wind units are marginal, production subsidies result in negative pricing for all generators, including baseload generators that are unwilling or unable to turn off for short periods of time. In many regions, regulators require planning reserve margins that mandate levels of supply beyond what an energy-only market would provide, while energy prices are often capped at $1,000/MWh or so, well below the perceived cost to a supply interruption known as the "Value of Lost Load".[45] Since power prices reflect the marginal cost, rather than the total cost of generation, baseload power plants are unable to recover their fixed costs during most hours, and rely on price spikes for this cost recovery. When power prices can't reach their natural highs during these spikes, baseload resources cannot recover their full costs from markets.

In competitive electricity markets, some ISOs operate capacity markets designed to provide this "missing money." These markets generally have time horizons of one year or less, with only two (PJM and ISO-NE) providing a three year outlook. As a result, there is limited price visibility for competitive power generators, which puts limits on the amount and tenor (i.e., time to maturity) that debt markets are willing to finance. Typically, debt markets finance thermal power plants built in competitive power markets over a seven to ten year timeframe, which is far less than the life-cycle of a thermal power plant. This mismatch in turn creates an implicit bias towards technologies with lower upfront capital costs that can recover costs in the short-run compared with technologies that may rely on a longer time frame for cost recovery.

In vertically-integrated markets, regulators are tasked with taking a long-term perspective, and overseeing a process by which regulated utilities also adopt a long-term perspective on investments in generation. This perspective not only includes ensuring reliability and keeping costs down, but also providing predictable electricity pricing to ratepayers. As natural gas prices rise, regulated utilities can turn to their baseload coal and nuclear fleet for power, while reducing reliance on more expensive natural gas-fired generation.

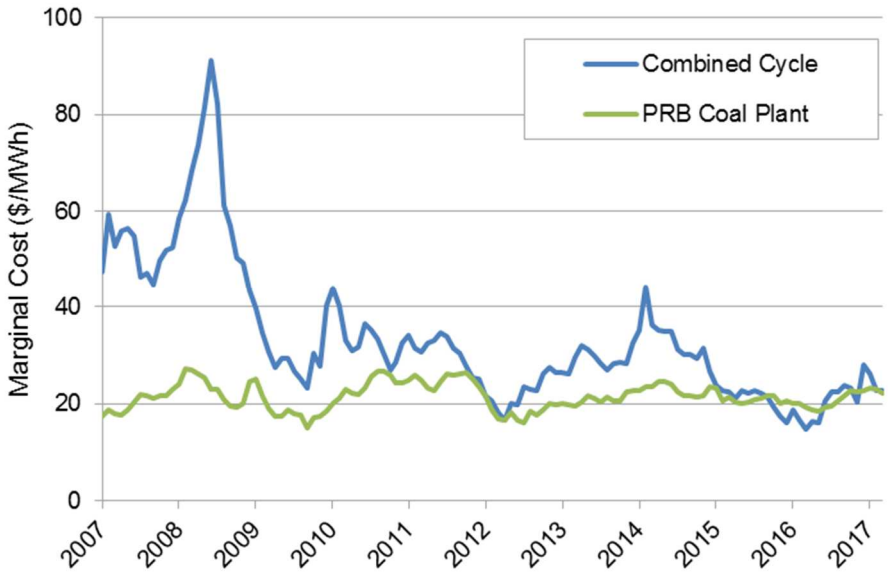
[45] This amount varies significantly by market and by customer class, but is generally accepted to be multiple thousands of dollars per MWh.

3.2 Natural gas prices are projected to rise

Over the last decade, monthly natural gas commodity prices have fluctuated on average between $2 and $12/MMBtu. Near-term movement often reflects drivers such as cold weather increasing demand, storage levels, and pipeline constraints. Long-term drivers include the expansion of fracking technologies that have opened up previously unrecoverable shale plays in the Marcellus region of Pennsylvania and elsewhere. However, while the expansion of fracking has driven gas prices to historic lows, natural gas prices have been volatile.

Over the last decade, coal pricing has been much more stable, reflecting far fewer supply and demand shocks. Over 80% of coal is purchased through multi-year contracts[46] for both the commodity and transportation, whereas natural gas is typically purchased on-demand and as-available. This is because contracting for long-term firm natural gas supply is expensive, and hedging against price volatility can be complicated, requiring a trading desk or going through a marketer. Additionally, gas purchased on an interruptible basis is subject to further daily volatility. For these reasons, the marginal cost of a power plant burning Powder River Basin ("PRB") coal is historically very stable (approximately $20-$30/MWh) compared to a representative combined cycle burning natural gas ($15-$90/MWh), as shown in Figure 3-2.

Figure 3-2: Illustrative Marginal Cost of a Natural Gas-Fired Combined Cycle Plant vs PRB-Burning Coal Plant ($/MWh)[47]



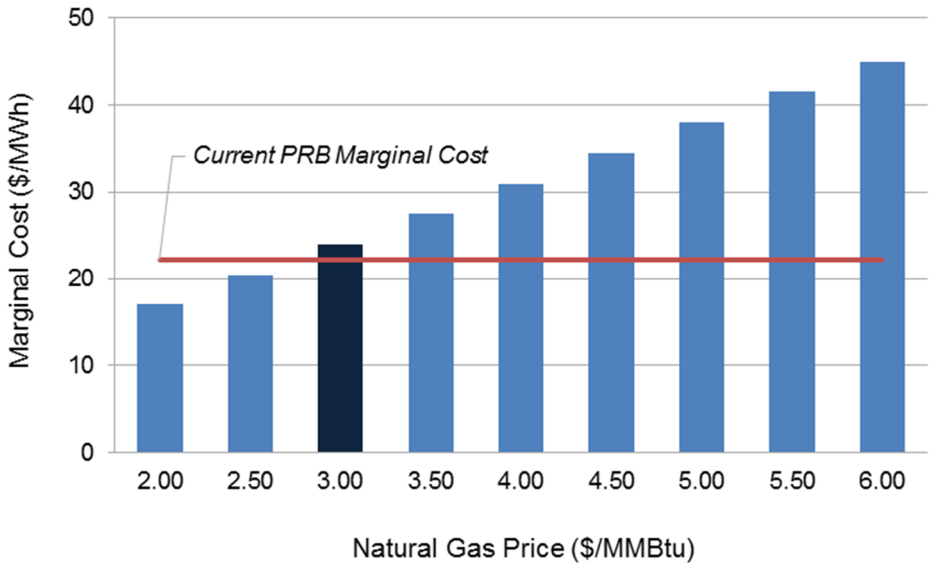
Natural gas-fired generation has been competitive with coal since late 2014. This is unusual, since coal plants have historically dispatched ahead of natural gas-fired plants. However, it would not take a significant rise in natural gas prices for coal-fueled generators to once again be advantaged relative to most natural gas combined cycle generators. Consensus forecasts for natural gas price recovery to these levels (i.e. above $4/MMBtu) is generally three to five years away, driven by higher power sector demand

[46] The length of an average coal purchase contract is over two years.

[47] Combined cycle reflects Henry Hub natural gas, a 7,000 Btu/kWh heat rate and $3/MWh variable operations & maintenance ("VOM") cost. PRB coal plant reflects a 10,000 Btu/kWh heat rate and $6/MWh VOM. Source: ABB's Energy Velocity Suite.

and increasing natural gas exports, including to Mexico via pipelines and globally in the form of Liquefied Natural Gas ("LNG").[48] This timeline is beyond the near-term horizon of wholesale markets, but well within the useful life of the average existing coal-fueled plant.

Figure 3-3: Marginal Cost of Illustrative Combined Cycle Plant at Different Natural Gas Prices[49]



When natural gas prices rise above $4/MMBtu, coal is poised to return to its traditional role as an infra-marginal baseload resource (see Figure 3-3), providing stable and low-cost power for ratepayers. Prudently retaining this coal-fueled capacity would provide significant hedge value against rising natural gas prices.

[48] In its most recent 2017 Annual Energy Outlook, EIA forecasts $4.90/MMBtu Henry Hub in 2020.

[49] Source: PA Consulting Group analysis.

4 CONCLUSION

This report has highlighted the benefits that existing coal-fueled generation provides to our current and future electricity system, and how these resources can be effectively leveraged to ensure the system remains reliable and resilient and prices remain stable. As the electricity system evolves, many of these requirements will take on greater importance. These requirements include reliability attributes such as inertia and frequency response, resiliency attributes advanced by diversity in technology and fuel supply, and stable pricing via reduced exposure to volatile natural gas prices.

Coal is well-positioned to provide many of these system attributes:

- Coal-fueled plants contribute to reliability through the rotational inertia of spinning generators that provide essential ancillary services, including frequency response, spinning reserves, and reactive power.
- Coal-fueled plants utilize a low-cost, domestically available fuel which can be stockpiled, is available for purchase on long-term contracts, and is used almost exclusively for electricity generation. These factors combine to make coal one of the most reliable generating resources, and its inclusion in the diverse mix of generating resources results in a more resilient grid.
- Coal-fueled generation contributes to long-term stable and low-cost power prices.

While often overlooked, these benefits should be part of the conversation when objectively weighing the contributions that various technologies make toward a reliable, resilient, and affordable electricity system. This conversation should furthermore acknowledge the varied regional market structures and generation mixes that shape policy. We encourage regulators and policymakers to recognize the value of a diverse mix of resources to ensure grid reliability and resilience.

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United States headquarters
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405 Lexington Avenue
New York, NY 10174
USA
+1 212 973 5900

Corporate headquarters
123 Buckingham Palace Road
London SW1W 9SR
United Kingdom
+44 20 7730 9000

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