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Ensuring resilient and efficient PJM electricity supply

The value of cost-effective nuclear resources in the PJM power supply portfolio

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About the report

The *Ensuring resilient and efficient PJM electricity supply: The value of cost-effective nuclear resources in the PJM power supply portfolio* report 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 of current PJM wholesale market distortions that increase the probability of uneconomic closure and replacement of PJM nuclear generating resources. This report is made up of two volumes. Volume 1 contains the main report, and Volume 2 contains the appendixes. This research was supported by Nuclear Matters.

The authors are exclusively responsible for all analysis and content.

Executive summary

PJM faces the potential loss of cost-effective nuclear resources that provide valuable resilience to the disruptive events that can affect normal power system operating conditions. This problem exists because ongoing wholesale market distortions are increasing the likelihood of uneconomic closures of existing PJM nuclear resources and the subsequent replacement by the fuel and technology mix in the current PJM new power supply pipeline (15% renewables and 85% natural gas–fired technologies). This analysis indicates that if nothing is done to prevent uneconomic nuclear closures and replacements, then the 65 million consumers relying on PJM grid-based power supply face

- **Less resilient PJM capacity availability.** This follows from the loss of the inherent resilience created by the weak correlation between nuclear and nonnuclear capacity availability risk factors, most recently observed during the polar vortex and bomb cyclone disruptive winter events. Since inherent resilience is costless to consumers, the associated increase in the cost to achieve PJM reliability levels to compensate for uneconomic nuclear closures means that an efficient trade-off between reliability benefits with costs results in a lower level of power system reliability.

- **Less consumer net benefits from electricity consumption.** The uneconomic retirement and replacement of PJM nuclear power plants reduces the consumer annual net benefit from PJM grid-based electricity. Since consumers value electricity more than what they pay for it, the net benefit of electricity purchases declines by $5–12 billion per year owing to higher retail prices and lower consumption levels. The loss in consumer net benefits is about 3 cents per kWh produced by existing PJM nuclear resources.

- **Less affordable electricity.** Annual PJM electricity supply costs increase the average retail price for electricity to consumers by 9–18% because nuclear resources are lower cost to continue to operate than they are to replace.

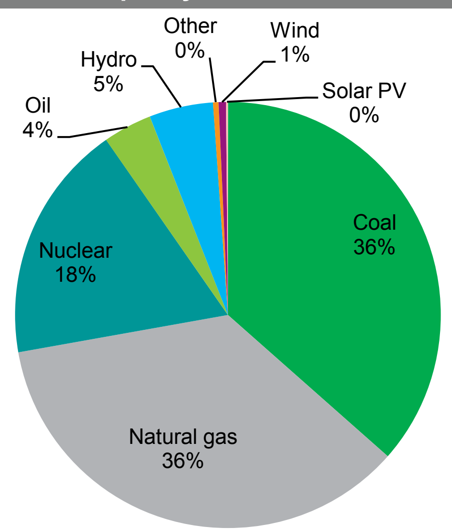
- **Less resilient PJM electric production costs.** Month-to-month variation (as measured in terms of standard deviation) in consumer monthly production costs increases by roughly 53% owing to the loss of the inherent electric production cost resiliency provided by the nuclear contribution to the current fuel diversity in the PJM electricity supply portfolio. Since monthly production costs represent about one-third of consumer monthly power bills, the variation in monthly consumer electricity bills is about 18% greater. Replacing the production cost resilience from nuclear resources with financial hedging instruments would involve an annual cost of about $714 million.

- **Less environmentally responsible PJM power supply.** PJM nuclear resources provide 88% of the PJM non–carbon dioxide (CO_2)–emitting electric production. If these nuclear resources close prematurely, then the net effect on PJM electric greenhouse gas (GHG) emissions is an annual increase of about 100 million metric tons of CO_2. PJM nuclear closures would remove 12 times more CO_2-free power supply than currently produced by all the wind and solar resources in PJM. To put this into perspective, the potential annual increase in PJM CO_2 emissions equals the CO_2 emissions produced each year by two-thirds of the vehicles on the road in PJM. The potential annual increase in CO_2 emissions imposes an annual environmental cost of about $4.3 billion based on the $43 per metric ton midrange estimate of the social cost of incremental CO_2 emissions.

The bottom line is that efficient power supply is diverse because no single fuel or technology is the lowest-cost source of supply to meet the base-load and variable segments of consumer demand and the uneconomic loss of the nuclear contribution to the PJM power supply portfolio caused by market distortions is a lose-lose proposition. The outcome involves both higher power production costs as well as higher CO_2 emissions. Since environmental responsibility requires making efficient environmental cost and benefit trade-offs, uneconomic PJM nuclear closures and replacements are not environmentally responsible.

Figure 1

PJM installed generation capacity, December 2016: 182 GW



Note: PV = photovoltaics.
Source: IHS Markit, PJM

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Electricity consumers reveal a preference for resilience to disruptive events affecting both power supply availability and electric production costs. The 19 PJM nuclear power plants are a cost-effective source of electric energy and capacity in the current diverse PJM power supply portfolio (see Figure 1).

PJM nuclear resources supply net dependable capacity to meet power system real-time demand levels, and PJM dispatches nuclear resources to cost-effectively align energy output with the steady 24/7 base-load segment of consumer demand that accounts for 60% of annual PJM electric load. The uneconomic retirement and replacement of PJM nuclear power plants would have reduced the consumer annual net benefit from PJM grid-based electricity by about $8 billion per year over 2013–16. This translates into a consumer net benefit per kilowatt-hour of PJM nuclear generation of about 3 cents per kWh.

PJM consumers benefit from efficient power supply diversity because it inherently increases the ability of grid-based power supply to withstand and reduce the magnitude and/or duration of disruptive events on both power supply availability and costs. Efficient power supply diversity exists because no single fuel or technology is the lowest-cost source of supply to meet the base-load and variable segments of consumer demand. As a result, cost-effective power supply under expected operating conditions involves employing an efficient mix of fuels and technologies in the power supply portfolio. However, expected operating conditions are subject to disruptions because all fuels and technologies have performance and cost risks. Since many of the key electric generation fuel and technology risk factors are not highly correlated, the cost-effective diversity in a power supply portfolio results in "not having all the eggs in one basket" and, thus, ***inherently*** mitigates the impact of disruptions from expected operating conditions.

In particular, the nuclear power plants in the PJM power supply portfolio provide consumers with inherent resilience in both power supply availability and affordability because the PJM nuclear capacity availability and production cost risk factors are not highly correlated with the risk factors of the other resources in the PJM power supply portfolio.

The value of the inherent capacity diversity provided by nuclear resources in the PJM power supply portfolio became apparent during recent deviations from expected winter operating conditions. During the deviation from normal winter conditions known as the polar vortex in January 2014, PJM hit a record wintertime peak demand of 141.8 GW. This severe cold snap did not reduce available nuclear capacity below its expected net dependable level. However, the severe cold snap did reduce available natural gas–fired capacity by 27% from the expected net dependable level.

The polar vortex episode revealed the inherent resilience arising from the lack of correlation between natural gas–fired capacity availability risk factors and the risk factors associated with nuclear, oil-fired, and coal-fired power plants. This lack of correlation allowed these resources that did not depend on natural gas to back up and fill in for the disproportionate limitations on natural gas–fired capacity availability during the polar vortex. Looking back, if the PJM net dependable nuclear had been replaced by an equivalent amount of net dependable natural gas–fired capacity along with an expanded natural gas supply infrastructure capable of providing the same natural gas–fired capacity availability (ratio of available capacity to net dependable rating) experienced during the polar vortex, then the available capacity on 7 January 2014 would have been 9.3 GW lower. Under these conditions, PJM would have had to fully exercise the remaining emergency operating procedures that provided an estimated equivalent of 2.7–3.7 GW of firm capacity and, therefore, would likely have been pushed beyond its limits and forced to shed some load during the polar vortex.

PJM responded to the lessons of the polar vortex by changing capacity performance rules. However, these changes did not eliminate the exposure of PJM power supply to natural gas–fired generation risk factors. The continued vulnerability of PJM to the availability of natural gas–fired capacity became apparent when PJM faced another significant deviation from normal winter operating conditions during the "bomb cyclone" event during the winter of 2017/18. The bomb cyclone cold snap was not as severe as the polar vortex episode. Yet the bomb cyclone was severe enough to reduce natural gas–fired capacity and constrain natural gas supply to PJM generators. As a result, the 35% of installed PJM capacity consisting of natural gas–fired resources accounted for 59% of the PJM capacity outages that drove the 7 January 2018 PJM installed capacity forced outage rate to 12.1%.

The inherent diversity of the PJM power supply portfolio reduced the magnitude and duration of the disruptions to expected PJM operating conditions during the cold snap known as the bomb cyclone. But the implication was clear—if the PJM net dependable nuclear capacity had been replaced by an equivalent amount of net dependable natural gas–fired capacity and the gas supply infrastructure had also been proportionately expanded to provide the same natural gas–fired capacity availability factor as experienced during the bomb cyclone, then the available PJM capacity on 7 January 2018 would have been 5.2 GW lower. Under these conditions, PJM would have had to exercise all emergency operating procedures and would likely have been pushed beyond its limits and forced to shed load during the bomb cyclone.

PJM natural gas–fired capacity availability appeared better during the bomb cyclone than during the polar vortex owing in part to the significant costs that natural gas–fired generators incurred to improve capacity availability in response to the PJM capacity performance rule changes. This cost to increase capacity resilience stands in stark contrast to the costless resilience inherently provided by the efficient fuel and technology diversity of a cost-effective PJM power supply portfolio. The cost implication is clear—if uneconomic closure and replacement of PJM nuclear resources results in the loss of inherent PJM power supply portfolio resilience, then restoring that lost resilience will impose additional costs on consumers.

The costly loss of inherent capacity availability and production cost resilience is one of the predictable negative impacts resulting from the uneconomic closure and replacement of PJM nuclear resources. This analysis quantified the potential impacts from the closure and replacement of nuclear capacity and energy in the PJM generating portfolio with an analysis of the closure and replacement of PJM nuclear resources under the operating conditions experienced from 2013 through 2016.

The findings of negative impacts from PJM nuclear power plant closure and replacement indicate that premature closure and replacement of existing PJM nuclear resources is not the result of efficient market dynamics generating cost-effective resource turnover. In an undistorted marketplace, effective cost-based competition sorts out the most efficient suppliers. Under these conditions, the exit of an unprofitable supplier benefits consumers. But to make this happen, existing suppliers would not exit the marketplace and be replaced by costlier alternatives.

The results of this study indicate that retiring existing PJM nuclear resources would trigger replacement by costlier alternatives. Such an outcome is inconsistent with an efficient market outcome and consistent with the results in a distorted marketplace that does not count all costs in the cost-based competition. Under competitive conditions with missing costs, market forces do not sort out the most efficient suppliers. Instead, market price signals support the operation of less cost-effective suppliers while more cost-effective suppliers are driven out of business.

PJM wholesale electric energy markets distortions arise from missing costs because price formation rules reprice security constrained market-clearing prices below power system marginal generating costs. In addition, current subsidies and mandates for some but not all non–CO_2-emitting competitive generators shift costs to taxpayers and alter PJM market demand and supply interactions resulting in lower market-clearing prices, at some times, enough to produce negative price levels. These energy market distortions disproportionately reduce cash flows for higher-utilization power supply resources. In addition, current uneven internalization of the full cost of CO_2 emissions among rival generators disproportionately impacts higher-utilization power resources with lower CO_2 emissions per megawatt-hour compared with the CO_2 emission intensity of the generating units whose short-run marginal cost (SRMC) bids are setting the market-clearing price.

PJM wholesale electricity capacity market distortions arise from federal and state environmental policies that subsidize and mandate capacity development and, thus, override market price–driven capacity entry, thereby delaying the point in time when electricity market demand and supply achieve long-run balance and suppressing capacity market-clearing prices.

PJM market distortions have a significant impact on competitive generator cash flows. The track record of persistent cost recovery shortfalls and bankruptcies of competitive generators, including natural gas–fired generators, indicate the magnitude of the problem. Other power systems provide examples of unresolved discord between public policies and market operations leading to market distortions that eliminated nuclear generation shares like current PJM nuclear generation shares within a dozen years. Consequently, the uneconomic closure of PJM nuclear resources is a plausible result from current market distortions. The recent FirstEnergy Solutions announcements to prematurely deactivate more than 4,000 MW of PJM nuclear resources are the leading edge of the potential loss of cost-effective PJM nuclear resources.

The most straightforward solution to the problem of uneconomic nuclear retirements involves reforming price formation rules to close gaps between marginal costs and market-clearing prices, along with putting an appropriate price on CO_2 emissions for all rival generators in PJM rather than subsidizing and mandating generation shares for some but not all non–CO_2-emitting generating technologies. However, since policy and market discord is entrenched, the probability is low that policy formulation will reverse course and quickly eliminate the underlying root causes of market distortions. Therefore, PJM market distortions are likely to persist. Under these conditions, other feasible policy options are under consideration to augment cash flows for cost-effective generating resources and produce outcomes closer to the results expected in an efficient market end state. These options involve providing compensation for attributes—such as cost-effective contributions to resilient capacity availability, contributions to resilient electric production costs, contributions to flexible operating capabilities, or contributions to lowering power system CO_2 emission levels.

Looking ahead, unresolved market distortions create inefficiencies that make PJM grid-based electricity supply less affordable, less reliable, less resilient, and less environmentally responsible. The implication is that the FERC Resilience Docket AD18-7-000 provides the opportunity to do something to address PJM market distortions and to avoid the consequences of uneconomic PJM nuclear power plant closures and the resulting significant declines in the consumer net benefit from PJM grid-based power supply.

Since PJM is the largest electricity market on earth and widely regarded as a model for electricity policy formulation and market design, actions to preserve the inherent resilience to electric availability and production cost levels provided by current cost-effective nuclear resources in the power supply portfolio have the potential to not only benefit electric consumers in PJM but also produce a highly influential example for other power systems to follow in addressing the consequences of market distortions arising from the lack of harmony between public policies and market operations.

Overview

This study focuses on the resilience impacts from the uneconomic closure and replacement of PJM nuclear resources for two reasons. First, current PJM market distortions disproportionately reduce cash flows for high-utilization and low–CO_2-emitting resources and make the premature loss of PJM nuclear resources a plausible scenario. Second, the inherent resilience provided from cost-effective nuclear in the PJM power supply portfolio is significant and expensive to replace.

Power system operating conditions are subject to disruptive events that can decrease the availability and increase the cost of grid-based power supply to consumers. As a result, consumers reveal preferences for cost-effective resilience in both power supply availability and electricity production costs.

Wholesale electric market operations can produce outcomes that meet consumer demands for electric supply resilience when public policies and wholesale operations are harmonized. However, resilience in power supply has become a strategic concern in the US power sector because the current lack of harmony between public policies and market operations is causing wholesale electricity market distortions and reducing power supply resilience. At the individual power plant level, market distortions are lowering cash flows and causing underinvestment in the resilience of power plant operations. At the power system level, market distortions are producing price signals that shape less efficient fuel and technology diversity in the power supply portfolio that decreases the inherent ability of an efficient power supply portfolio to withstand and reduce the magnitude and/or duration of disruptive events to expected operating conditions. The combination of plant and power system impacts creates an electricity system with less resilience compared with the level of resilience expected from an undistorted, efficient wholesale electricity market outcome.

The link between policy and market discord, market distortions, and resilience losses is not appreciated by some industry observers who believe that wholesale electricity markets are currently working well with subsidies that favor some rival generators and not others, with policies that count some costs but not others in the marginal cost–based competition to generate electric energy, and with rules that generate persistent gaps between power system marginal generating costs and market-clearing energy prices.

The blind spot to market distortions supports assessments that insufficient nuclear power plant cash flows are the result of existing nuclear plants being uncompetitive with natural gas–fired competitors that gained a competitive advantage from downward pressure on natural gas prices due to development of shale natural gas resources. Such assessments reflect the perception that nuclear closures are simply the result of the "creative destruction" in an efficient marketplace.[1] From this perspective, there is no distinction between economic and uneconomic nuclear power plant retirements. Further, the blind spot to market distortions fails to reconcile with the financial track record of the competitive natural gas–fired generators across the past 15 years, where the rule rather than the exception was inferior risk-adjusted returns to broader capital market benchmarks, significant asset write-downs, and periodic bankruptcy reorganization. The implication is that these natural gas–fired competitive power generators are not "winning" in the marketplace but instead are also being impacted by market distortions suppressing cash flows below levels expected in an undistorted market outcome.

Resilience in power supply is a strategic concern for the PJM wholesale electricity market because PJM operates the world's largest competitive wholesale electricity market and coordinates the power system security-constrained movement of wholesale electricity in all or part of 13 states (Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, and West Virginia) and the District of Columbia. PJM centrally dispatches generation through a bid-based competitive process that determines power system security-constrained locational market prices in day-ahead and real-time electric energy markets as well as determines prices in capacity and ancillary service markets.

This study analyzes the resilience impacts from the perspective of the 65 million consumers who rely on PJM for affordable, reliable, resilient, and environmentally responsible grid-based power supply. From this perspective, the power system objective is to cost-effectively meet the multiple dimensions of consumer demand by efficiently integrating a reliable and resilient mix of fuels and technologies to supply consumers with the electricity that they want, whenever they want it, at prices that reflect all the costs of the grid-based security-constrained economic dispatch of the power supply portfolio.

Consumers reveal preferences for resilient electric supply availability

Electric system operating conditions are uncertain because the availability of all generating fuels and technologies are vulnerable to disruptions from mechanical or software failures, accidents, political interventions, overloading network pathways, regulatory changes, extreme weather events, and physical or cyber attacks.

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

Resilience in grid-based power supply provides the ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such events.[2]

Consumers benefit from resilient electric supply availability that reduces the magnitude and duration of electric service outages. Estimates of total annual power outage costs for US consumers exceed hundreds of billions of dollars per year.[3] Of course, consumer outage impacts vary depending on the size, timing, and duration of an outage, but available estimates of actual annual outage costs and durations indicate that electric service disruptions in the United States result in about $75 billion per hour of electric service interruption costs.[4] This cost translates into a $170/kWh incremental outage cost.

Estimates of the value of lost load are more than 100 times greater than the price consumers pay for electricity. These value of lost load estimates align with the high valuations consumers reveal when they choose to purchase backup generation resources to provide uninterrupted power supply to critical electrical applications. US grid-based power supply is typically available 99.97% of the time, and 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 US average price of 12.6 cents per kWh that households pay for grid-based power supply.

Consumer choices to invest in backup generation reveal high valuations for avoiding incremental grid-based outages. Many commercial and industrial customers—especially customers with critical electric applications in hospitals and data centers—choose to install backup generation. On the residential side, more than 1 million US residential consumers have chosen to invest in emergency backup generation systems. Within PJM, a surge of residential consumer investments in backup generation followed the Hurricane Sandy outages in 2012, even though the PJM electricity supply is available over 99% of the time.[5]

Consumers chose to back up supply for some, but not all, electric loads. These choices reveal that consumers weigh the costs and benefits of improving electric reliability across all electric end uses and determine that making a power system 100% reliable for all applications is not cost effective. These consumer choices reveal that consumers recognize reducing the probability of grid-based electric supply outages to zero will cost far more than the high, but not unlimited, value that they place on unserved electric load. Therefore, from a consumer perspective, cost-effective grid-based power supply meets their preferences for resilience in power supply availability by achieving a level of reliability that balances the marginal costs and benefits of reliability investments.

Current value of lost load estimates put the benefit of avoiding an additional hour of electricity outages in PJM at about $12.5 billion. PJM is responsible for maintaining mandatory reliability standards in grid operations and network planning established by the North American Electric Reliability Corporation and approved by the Federal Energy Regulatory Commission (FERC). To meet reliability obligations, PJM establishes a forward demand curve for capacity designed to produce capacity price signals that pace investment in power supply to achieve a target loss of load probability for the power system.

2. National Infrastructure Advisory Council, *Critical Infrastructure Resilience Final Report and Recommendations,* 8 September 2009, https://www.dhs.gov/sites/default/files/publications/niac-critical-infrastructure-resilience-final-report-09-08-09-508.pdf, retrieved 21 February 2018.

3. 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.

4. 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, https://emp.lbl.gov/publications/updated-value-service-reliability, retrieved 29 August 2017.

5. Ken Belson, "Power Grids Iffy, Populous Areas Go for Generators," *New York Times,* 24 April 2013, http://www.nytimes.com/2013/04/25/business/energy-environment/generators-become-must-have-appliances-in-storm-battered-areas.html, retrieved 21 February 2018.

PJM consumers benefit from efficient power supply diversity because it inherently increases the ability of grid-based power supply to withstand and reduce the magnitude and/or duration of disruptive events on power supply availability. Efficient power supply diversity exists because no single fuel or technology is the lowest-cost source of supply to meet the base-load and variable segments of consumer demand. As a result, cost-effective power supply under expected operating conditions involves employing an efficient mix of fuels and technologies in the power supply portfolio. However, expected operating conditions are subject to disruptions because all fuels and technologies have performance risks. Since many of the key electric generation technology risk factors are not highly correlated, the cost-effective diversity in a power supply portfolio results in "not having all the eggs in one basket" and, thus, ***inherently*** mitigates the impact of disruptions from expected operating conditions.

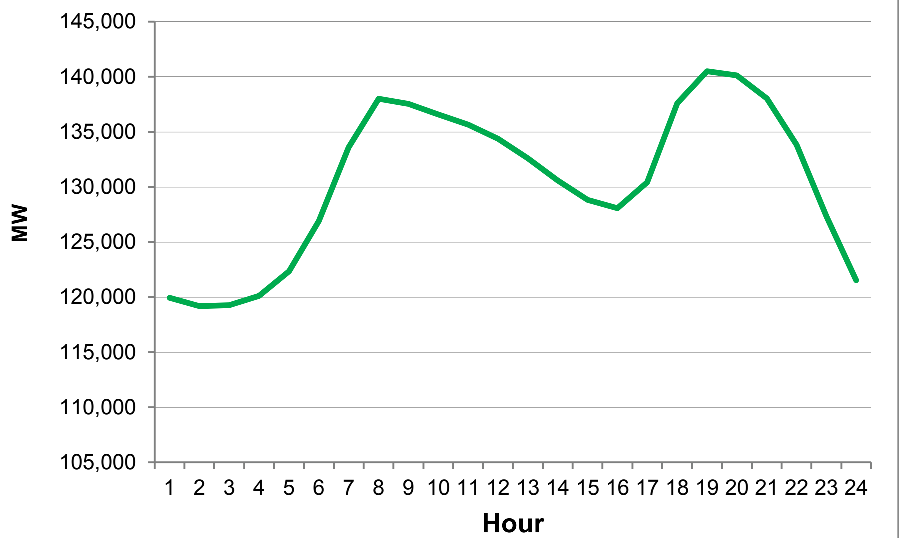
The uneconomic closure of PJM nuclear capacity results in the loss of inherent resilience in PJM capacity availability. Since cost-effective nuclear generation in the PJM supply portfolio provides consumers with inherent resilience in capacity availability, this resilience comes at zero cost to consumers. Consequently, achieving the same level of power system reliability following uneconomic PJM nuclear closure and replacement requires incurring additional costs. As a result, if PJM meets consumer preferences to balance the costs and benefits of reliability investments, then the result of uneconomic nuclear closures and replacements will be a lower cost-effective level of power system reliability and higher expected outage costs for consumers.

Recent disruptive events to expected winter operating conditions in PJM illustrate the benefits of the resilience provided by the diverse technology and fuels in the electric supply portfolio, and the responses to these winter episodes indicate the cost associated with increasing the resilience of electric capacity availability.

The polar vortex was a recent disruptive event involving a significant deviation from normal winter conditions during January 2014. Figure 2 shows the aggregate consumer hourly load on 7 January 2014, when the polar vortex caused PJM to hit a record wintertime peak demand of 141.8 GW.

Figure 2

PJM hourly load on 7 January 2014



Source: IHS Markit, PJM © 2018 IHS Markit

On the supply side, polar vortex conditions in the PJM power system caused significantly higher-than-expected unavailability from natural gas–fired generating units linked, in many cases, to abnormally high natural gas pipeline supply constraints. Although the polar vortex did not reduce electric supply just from natural gas–fired resources, the natural gas–fired resources were nevertheless the hardest-hit supply resource. Table 1 reports the actual PJM installed capacity in January 2014 and the associated net dependable ratings by technology and fuel type.[6] Net dependable capacity measures the

6. Monitoring Analytics, LLC, *State of the Market Report for PJM (2014)*, 12 March 2015, http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2014/2014-som-pjm-volume2.pdf, retrieved 27 February 2018.

Table 1

PJM polar vortex capacity

Generator fuel type	Installed capacity (MW)	Available firm capacity factor	Net dependable capacity (MW)	Total actual outages on 7 January 2014 (MW)	Actual firm capacity on 7 January 2014 (MW)	Ratio of actual firm to net dependable capacity (MW)
Coal	75,545	77.2%	58,320	13,700	61,845	1.06
Gas	53,395	87.9%	46,956	19,000	34,395	0.73
Nuclear	33,077	92.3%	30,530	1,400	31,677	1.04
Hydro	8,107	88.0%	7,134	N/A	N/A	N/A
Oil	11,314	92.3%	10,443	N/A	N/A	N/A
Wind1	872	100%	872	N/A	N/A	N/A
Solar1	84	100%	84	N/A	N/A	N/A
Other	701	100%	701	N/A	N/A	N/A
Not classified				8,512	12,567	
Total	183,095		155,041	42,612	140,483	0.91

1. PJM calculates solar and wind installed capacity by reducing nameplate capacity by 62% and 87%, respectively.

Source: IHS Markit, PJM

expected capacity available from a resource under expected peak demand power system conditions. In PJM, the net dependable capacity of renewable solar and wind resources is typically 13% and 38%, respectively, of the capacity rating associated with operation under favorable conditions. Natural gas–fired generating units have a net dependable rating of 85–90% of the nameplate capacity, and existing PJM nuclear capacity has a net dependable rating of 92% of nameplate capacity. The table also shows the actual outage rates experienced during the polar vortex on 7 January 2014 and the associated actual firm capacity available by technology and fuel type.[7] Resilient capacity availability is a concern because disruptions to expected conditions during peak demand conditions can cause correlated outages for power plants relying on the same fuels or technologies and thus cause the actual overall capability of a class of generating resources to fall short of the expected aggregate net dependable capacity.

The polar vortex experience revealed that a severe cold snap disproportionately constrained the actual available capacity relative to the net dependable capacity of natural gas–fired generating resources. The polar vortex experience also revealed that the lack of correlation between the risk factors associated with natural gas–fired generating resources and the risk factors associated with other resources allowed nuclear, oil-fired, and coal-fired power plants to offset some of the disproportionate limitations on natural gas–fired resources.

A retrospective analysis of the polar vortex provides important resilience lessons because, as a July 2017 National Academies of Sciences, Engineering, and Medicine report notes, a process of continual learning from past events is essential for enhancing the resilience of the grid.[8]

PJM was in a fortunate position that a surplus of installed capacity was present in 2014 when the reported systemwide reserve margin was 22.5% rather than the long-run reserve margin target of about 16%. Analysis of PJM operating under polar vortex conditions shows that as capacity reserves decline, PJM approaches the point at which further reductions in available supply would likely produce increasingly large outage costs. Table 2 shows that as additional net dependable nuclear capacity is removed from the PJM supply portfolio and replaced by equal amounts of net dependable natural gas–fired capacity, the expected consumer outage costs

7. In the May 2014 report *Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events*, PJM quantified power supply reserves available to its system during the peak period on 7 January 2014, including 500 MW of 10-minute synchronized reserves, 1,167 MW of 10-minute nonsynchronized reserves, and 1.1–2.0 GW of temporary voltage reduction. Although other actions may have been available, such as purchasing additional emergency energy or recalling shared reserve obligations from neighbors, this analysis does not include the potential for PJM to purchase additional energy or recall additional obligations that PJM provided to neighbors.

8. National Academies of Science, Engineering, and Medicine, *Enhancing the Resilience of the Nation's Electricity System*, National Academies Press, Washington, DC, 2017, p. 3, https://doi.org/10.17226/24836, retrieved 13 December 2017.

under polar vortex conditions rose at an increasing rate from $153 million to $6.7 billion.

The polar vortex episode indicates that if the PJM nuclear net dependable capacity had been replaced by an equal amount of net dependable natural gas–fired generating capacity and the gas supply infrastructure had also expanded in proportion to provide the same forced outage rate of natural gas–fired generation during the polar vortex, then the firm capacity available on 7 January 2014 would have been 9.3 GW lower. The results indicate that replacing PJM nuclear capacity with natural gas–fired capacity reduces the risk diversification in the PJM power supply portfolio. Since nuclear net dependable capacity risk factors are not highly correlated with natural gas–fired net dependable risk factors, the expected overall available capacity is higher with a combination of nuclear and natural gas–fired capacity compared with the same amount of capacity consisting entirely of natural gas–fired resources. Therefore, the increase in correlation to risk factors within a generation portfolio results in an increase in the overall power system loss of load probability. Under the conditions of closure and replacement of PJM nuclear net dependable capacity with an equivalent amount of net dependable natural gas–fired capacity, PJM would likely have been pushed beyond the power system supply limits and thus forced to shed load during the polar vortex operations even if PJM employed the remaining emergency operating procedures that provided an estimated equivalent of 2.7–3.7 GW of firm capacity.

Table 2

2014 polar vortex scenario analysis to determine the resiliency value of the existing diverse power supply portfolio

	31 December 2016 capacity	**31 December 2016 capacity less Oyster Creek and Three Mile Island (1.47 GW)**	**31 December 2016 capacity less Oyster Creek, Three Mile Island, Davis-Besse, Perry, and Beaver Valley (5.5 GW)**
Hours of outage	3	5	11
Average shortfall (MW)	301	1,386	3,586
Total shortfall (MWh)	903	6,930	39,443
Cost per unserved MWh (dollars)	170,000	170,000	170,000
Total cost of shortfall (million dollars)	**153**	**1,178**	**6,705**

Source: IHS Markit

The polar vortex experience led PJM to examine the poor generator capacity availability. The examination exposed the lack of clarity in the PJM capacity market regarding the definition of the capacity commodity. PJM responded by developing capacity performance rules for its capacity marketplace designed to provide larger capacity payments for the most available resources, including performance bonus payments for overperforming participants as well as higher penalties for nonperformers. FERC approved PJM's rule changes in June 2015.

Since the polar vortex, 8,922 MW of coal-fired capacity and the 608 MW Oyster Creek, 837 MW Three Mile Island, 908 MW Davis-Besse, 1,268 MW Perry, and 1,872 MW Beaver Valley nuclear plants announced plans for closure. In addition, PJM added 11,715 MW of natural gas–fired generating capacity by the end of 2016. As a result, the exposure of PJM electric supply to the risks in the natural gas supply chain increased because the PJM electric supply portfolio became more natural gas dependent.

Implementing the PJM capacity performance rules showed that increasing PJM power supply resilience from natural gas–fired resources came at a cost. PJM surveyed 100 units (62 GW of the 93 GW) of the generators that committed to the capacity performance auction for the 2016/17 delivery year to understand the costs being incurred to comply with the new capacity performance requirements.[9] Table 3 summarizes the types

9. "Capacity Driven Performance Investments," PJM, October 2016, http://www.pjm.com/-/media/committees-groups/committees/mc/20161024-webinar/20161024-item-03-resource-investments-in-response-to-capacity-performance-requirements.ashx, retrieved 27 March 2018.

Table 3

Capacity performance investments in PJM

Investments	Description	MW	Percentage of total surveyed	Low (million dollars)	High (million dollars)	Average (million dollars)
Increased staffing per station	Staff generators 24 hours per day, 7 days per week to ensure unit readiness and decrease notification time	424	1%	$1	$1	
Generator infrastructure	Long-term maintenance upgrades (winterization and major unit overhauls)	17,991	29%	$2	$100	
Firm fuel supply	Gas generators procuring firm transportation services; upgrades to dual-fuel capability; installation of on-site oil storage tanks	10,110	16%	$30	$100	
Multiple unit investments	Two or more of the above	3,554	6%	N/A	N/A	
Environmental investments	Emission control upgrades to optimize megawatt-hour output while staying within emissions limits	2,150	3%	N/A	N/A	$32

Source: IHS Markit

of investments the PJM generators reported along with the range of costs for each type of investment and the associated capacity involved in each response.

PJM capacity performance rule changes and the increased reliance on natural gas–fired resources altered the exposure of PJM power supply to natural gas–fired generation risk factors. The current vulnerability of PJM to the availability of natural gas–fired capacity became apparent when PJM faced another significant deviation from normal winter operating conditions during the bomb cyclone event during the winter 2017/18. The bomb cyclone cold snap was not as severe as the polar vortex episode, yet natural gas–fired capacity availability was again disproportionately reduced. The bomb cyclone conditions drove the 7 January 2018 PJM installed capacity forced outage rate to 12.1%, and the 35% of installed PJM capacity that consists of natural gas–fired resources accounted for 59% of the PJM capacity outages.

The bomb cyclone episode indicates that if the PJM net dependable nuclear capacity had been replaced by an equivalent amount of net dependable natural gas–fired capacity and the gas supply infrastructure had also been proportionately expanded to provide the same natural gas–fired capacity availability factor as experienced during the bomb cyclone, then the available capacity on 7 January 2018 would have been 5.2 GW lower. Under these conditions, PJM would have had to exercise the remaining emergency operating procedures and would likely have been pushed beyond its limits and forced to shed load during the bomb cyclone.

The 2014 polar vortex and the 2017/18 bomb cyclone events show that replacing the net dependable PJM nuclear capacity with an equivalent amount of net dependable natural gas–fired capacity results in a higher loss of load probability and a lower level of reliability. The costs incurred to increase resiliency in response to the PJM capacity performance rules indicate that if unresolved PJM market distortions lead to uneconomic nuclear power plant closures, then replacing the lost resiliency provided by these resources in the generation portfolio will involve significant costs. Since cost-effective nuclear resources in the PJM supply portfolio provide inherent capacity resilience, replacing this source of zero-cost capacity resilience results in higher power bills for consumers.

Since the uneconomic closure of PJM nuclear capacity increases the cost of achieving the equivalent level of capacity resilience, adjustments to the PJM capacity demand curve are likely to replace only some of the lost resilience because a rebalancing of the costs and benefits of capacity resilience results in a lower level of cost-effective resilience.

The bottom line is that uneconomic PJM nuclear retirements will result in higher costs of capacity resilience, lower levels of cost-effective reliability, and higher expected annual consumer outage costs.

Consumers reveal preferences for affordable electric supply with production cost resilience

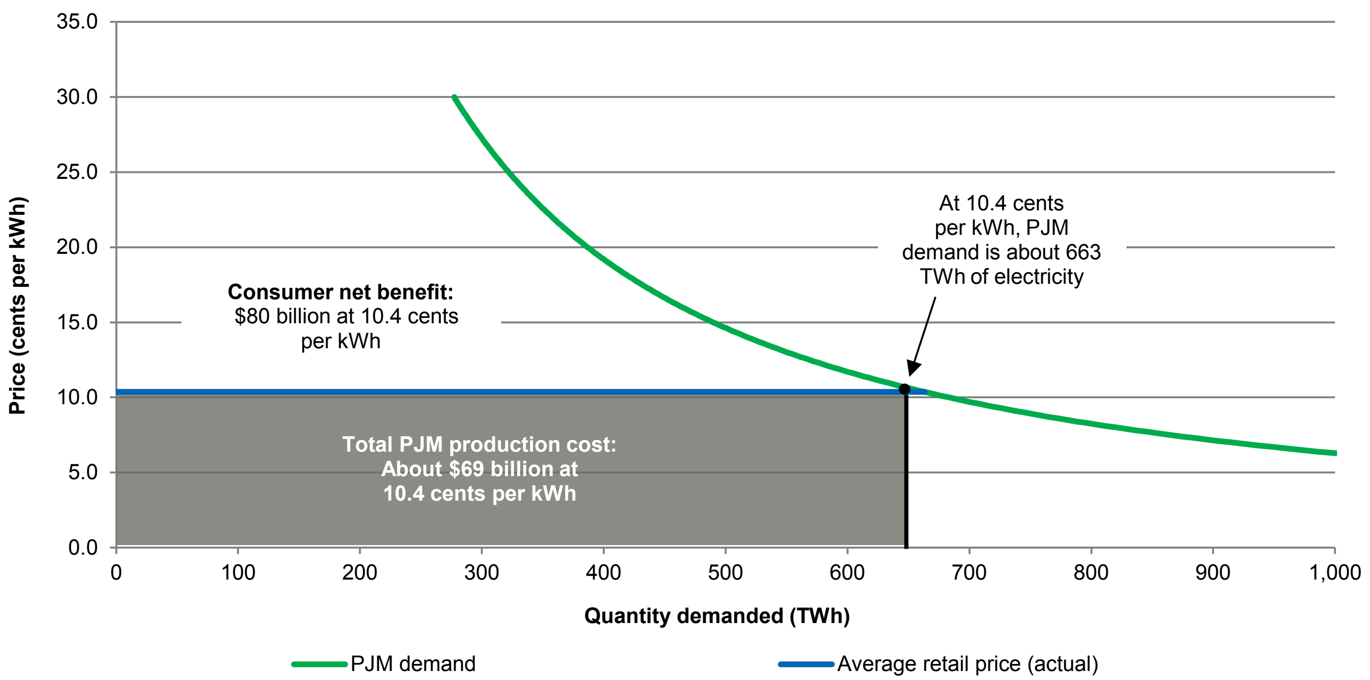
Consumers reveal a preference for affordable electric service. In 2016, electricity consumers within PJM purchased 663 billion kWh of grid-based power and paid an average retail price of 10.4 cents per kWh. These consumers had a choice to purchase electricity from the grid or to generate their own electricity off the grid. Self-generation is typically far more expensive than grid-based electricity supply because regional power grids can integrate a cost-effective mix of fuels and technologies that exploit available economies of scale that are well beyond the scale of self-generation. Therefore, the choices of most households and businesses to purchase grid-based electricity reveals a preference not to pay more than is necessary for electricity service.

Consumers also reveal that they value grid-based electricity more than what they pay for it. Consumers reveal the value that they place on different amounts of grid-based electricity purchases through 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, but not all, of the electricity that they purchased at the lower price. This change in consumption indicates that the value of the forgone electricity consumption was not worth the higher price and, conversely, that the value of the new level of electric consumption is greater than or equal to the new higher price.

Analyses of consumer behavior allows for the estimation of the relationship between the amount of electricity consumers purchase at different price levels—a relationship illustrated by the 2016 aggregate PJM grid-based electricity demand curve shown in Figure 3. Appendix A explains the statistical analyses of the long-standing differences in electricity retail price and consumption levels across states and consumer segments.

Figure 3

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



Source: IHS Markit

The area under the PJM demand curve from the origin to the actual consumption level in 2016 provides an estimate of the total value consumers in PJM put on electricity consumption. In 2016, a conservative estimate of the total value consumers in PJM put on electricity consumption was $149 billion. The estimate is conservative because it measures only the area under the PJM demand curve below the 30 cents per kWh level. The 30 cents per kWh price is the highest observed retail price in the United States, and limiting the price range in this assessment aligns with the statistically reliable demand curve estimated across the range of observed retail price levels in the United States.

Figure 3 also shows the observed 2016 average retail price (10.4 cents per kWh) and the corresponding observed level of aggregate consumer electricity consumption on the demand curve (663 billion kWh). The shaded area of the rectangle defined by the average retail price times the level of electricity consumption shown in Figure 3 indicates the $69 billion direct cost of grid-based electricity to PJM consumers in 2016.

Electricity consumption produces a net benefit for consumers equal to the value they place on their electricity consumption minus the direct cost of the electricity. Economic textbooks describe this value of consumption over what consumers pay as the "consumer surplus."

Table 4 shows that the 2016 PJM consumer net benefit from grid-based electricity consumption was about $80 billion along with estimates of the consumer net benefit from consumption of PJM grid-based power supply in 2013 through 2015. The implication is clear—consumers in PJM valued the electricity that they consumed over the recent past more than twice the amount that they paid for it.

Table 4

PJM consumer net benefits, 2013–16
(billion dollars, nominal)

Year	Revealed consumer electricity valuation	Consumer direct retail electricity supply cost	Consumer net benefit	Ratio of electricity value versus cost
2016	$149	$69	$80	2.2
2015	$148	$69	$78	2.1
2014	$148	$68	$80	2.2
2013	$145	$66	$80	2.2

Source: IHS Markit, Energy Information Administration (EIA) © 2018 IHS Markit

With this consumer benefits to cost ratio, it is not surprising that consumers complain when electric service restoration from an outage is slower than expected, even though a continuing outage lowers the consumer's power bill.

Analysis of consumer net benefits from grid-based electricity consumption indicates that maximizing consumer net benefits requires efficient electricity production. Since consumers demand different amounts of grid-based electricity at different points in time, an efficient electric supply portfolio involves a diverse mix of fuels and technologies that reflect a cost-effective alignment of available alternative electric generating resource performance characteristics to the pattern of aggregate consumer demand through time.

Nuclear resources are part of the cost-effective PJM fuel and technology power supply mix because nuclear output cost-effectively aligns with the steady 24/7 base-load segment of consumer demand that accounts for 60% of annual PJM electric load. As a result, replacing existing PJM nuclear resources with costlier power supply alternatives is uneconomic. The implication is that if uneconomic nuclear power plant closures and replacements make PJM grid-based electricity more expensive than it needs to be, then consumers lose quantifiable net benefits from electricity consumption.

Consumer net benefits from electricity consumption are uncertain because electricity production costs are uncertain. Power supply cost risk factors include the uncertainty in relative fuel prices for power generation caused by multiyear fuel price cycles, strong seasonal price movements, and periodic episodes of extreme price spikes reflecting the impact of disruptions in normal operating conditions in the fuel supply chain.

The shale natural gas revolution continues to benefit the US economy and to make natural gas–fired generating resources a major component of cost-effective power supply portfolios. Natural gas–fired resources are part of the cost-effective PJM power supply mix, particularly as a flexible resource to meet the variable segment of PJM aggregate consumer demand. This role for natural gas–fired resources results in the delivered cost of natural gas disproportionately affecting the cost of PJM electricity to consumers. Rival natural gas–fired generators' SRMC supply bids set the market-clearing wholesale electric energy price in response to changing demand levels in the PJM marketplace most of the time. As a result, the natural gas–fired share of marginal generation is greater than the natural gas–fired share of overall generation. Thus, the marginal costs of natural gas–fired resources exert a disproportionate influence on overall PJM wholesale price setting.

PJM natural gas–fired generators face long-run natural gas price cycles. The expected operating lifetime of a natural gas–fired power plant spans several decades. This links the input fuel price and fuel availability at these power plants to the long-run dynamics of the natural gas business landscape. A brief review of the dramatic changes in the natural gas industry landscape across the past several decades illustrates how several factors—disharmony between market forces and regulatory processes, consumer and producer recognition and adjustment lags, and changes in technology—combine to create dynamic natural gas price cycles in the long run.

- In the 1970s, the oil embargoes generated historically high oil prices and competitive forces drove the substitution of natural gas for oil in many energy end-use applications in the US economy, including in the generation fuel input mix for electric generation. However, at that time, disharmony between the regulatory process and competitive forces created disconnects between demand and supply trends and caused a failure to provide a sufficient price signal to incentivize development of the needed additional natural gas supply. The resulting shortages not only produced historically high price levels but also forced natural gas curtailments to consumers and ultimately generated legislated restrictions for the use of natural gas. These conditions led to contractual commitments between consumers and producers focused on security of supply, which later proved expensive as the natural gas industry moved into an era of deregulation and lower prices.

- In the 1980s, the tension between regulatory processes and market forces drove the deregulation of the natural gas industry, which resulted in a greater reliance on competitive markets to determine investment, resource development, and price levels.

- In the second half of the 1980s and in the 1990s, the transition to rely more on market forces and less on regulatory processes proved disruptive to the existing contractual commitments made during the prior era's regulatory regime. Market forces, combined with actions to unwind regulatory arrangements, produced an era of supply increases outpacing demand increases. These conditions produced historically low natural gas prices. Eventually, this "gas bubble" discouraged drilling for additional natural gas supply development while, at the same time, encouraging the growth of a natural gas–fired power plant development pipeline.

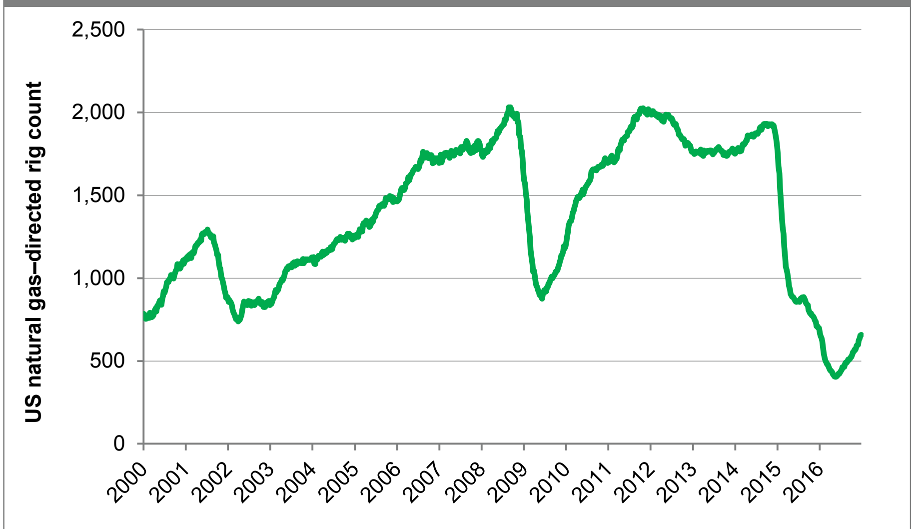
- In the early 2000s, the failure to recognize and adjust to the increasing gap between rising natural gas demand and the gradual depletion of conventional natural gas resources led to a multiyear upswing in natural gas prices and triggered investments to enable imports of LNG to satisfy expected increases in demand at these higher price levels. However, the upswing in natural gas prices drove the development of hydraulic fracturing techniques along horizontal drilling capabilities that unleashed shale and tight sands natural gas production, which led to aggregate supply outpacing demand by 2007 and subsequently causing a dramatic price decline from 2008 to 2009.

- In the 2010s, the evolving state of technology and associated declining marginal cost of shale gas resource production drove the need to reconfigure the natural gas supply chain to accommodate the changing flow patterns arising from the shift in the geographic center of gravity of natural gas production toward Appalachia and the concentration of demand growth in the south and southwest—a shift that is currently proving to be a challenge to the timely delivery of incremental supply to meet the needs of areas with growing demand. Low-probability but high-impact events such as the polar vortex in 2014 and the bomb cyclone in 2017/18 are exposing the current vulnerabilities in the shifting natural gas supply chain.

The current natural gas business landscape remains dynamic. Although innovations in the extraction of shale natural gas continue to significantly expand the economically recoverable natural gas resource base, the typical shale gas well has a more rapid production decline rate through time compared with a conventional natural gas well. As a result, shale gas production must be continually replenished by additional in-fill drilling or new exploratory drilling and field development. However, the natural gas supply chain—including wellhead and transportation capacity—is capital intensive, and investment requires a sufficient price signal to incentivize the development of new supply. Multiyear lags exist between the recognition of the price signal, the capital investment decision, the eventual production increase, and the expansion of pipelines and storage facilities. These natural gas industry recognition and adjustment lags cause the high degree of variation in the US natural gas–directed rig count (see Figure 4).

Figure 4

US weekly natural gas–directed rig count, 2000–16



Source: IHS Markit, Baker Hughes

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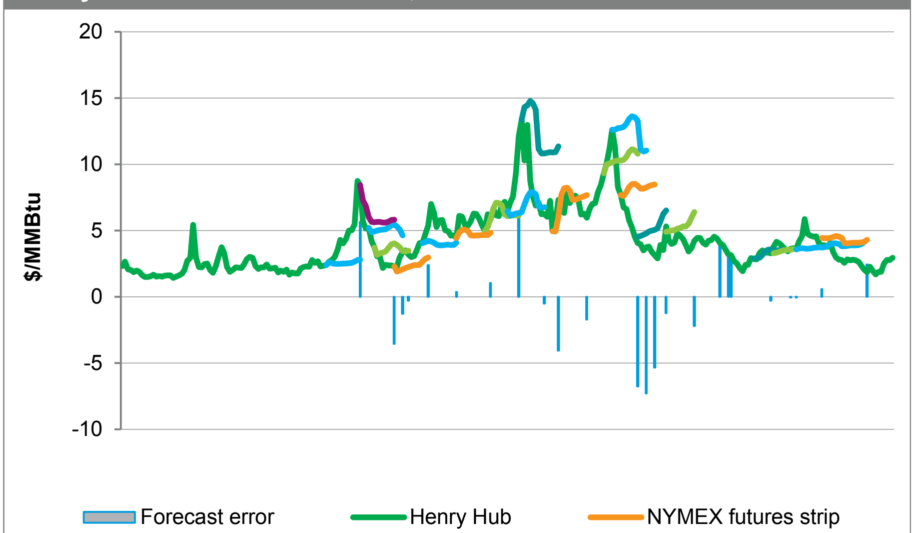
x

Figure 5

Henry Hub and NYMEX futures, 1994–2016



Source: IHS Markit, ABB Velocity Suite

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The swings in drilling activity are a driver of the long-run natural gas price cycles shown in Figure 5. Anticipating the timing of these multiyear price cycles has proven difficult as the Henry Hub futures price strips that are regarded as the marketplace consensus forecast of prices have proven to be a poor and biased indicator of the future Henry Hub spot price.

The drivers of multiyear natural gas price cycles are not going away, and neither is the difficulty in anticipating the timing of these price cycles. Prudent risk management involves recognizing the risk profile associated with multiyear delivered natural gas price cycles with hard-to-predict timing across the operating lifetime of a natural gas generating plant.

Natural gas deliverability constraints also involve multiyear cycles. Competitive natural gas–fired generators require pipeline capacity to move natural gas from the well to the burner tip. However, since a natural gas–fired generator's future fuel requirements are uncertain, competitive generators are unlikely to contract for long-term pipeline capacity that fully covers fuel delivery requirements. In addition, competitive natural gas–fired generator cash flow shortfalls due to market distortions reduce the financial capacity of these generators to pay for the desired partial contracting of the firm fuel supply. Consequently, the construction of power plants without firm transportation capacity sets up the possibility that natural gas fuel deliverability may not keep pace as power generation requirements change through time.

Significant natural gas pipeline investment is currently needed because the shale gas revolution shifted the location of natural gas supply and altered natural gas flow patterns away from the flow patterns dictated by delivering peak winter natural gas demand for home heating demand that shaped much of the existing gas pipeline infrastructure topography. The rise of the Marcellus Shale, in which there was no production as recently as 2008, currently accounts for 40% of US production and significantly altered the center of gravity of production in North America, with the associated attendant stress on the pipeline grid.

Physical pipeline flow constraints exist and increase the probability that all the natural gas needed for power generation will not always be available. Construction of pipeline infrastructure is triggering increasing political opposition, particularly in the eastern United States, and this political opposition to new pipelines limits the possibility of eliminating natural gas deliverability constraints.

Hydraulic fracturing has become controversial, and since it is the primary technological innovation that drove the growth of US shale gas production, natural gas supply hinges on the future of hydraulic fracturing. A permanent ban on hydraulic fracturing exists in some states, and if the political forces behind these bans can produce temporary or wider constraints or bans on hydraulic fracturing in the future, the impacts will quickly diminish production owing to the high initial decline rates that characterize shale production.

The current PJM natural gas supply chain operates at a relatively high utilization factor, with wellhead productive capacity routinely operating at a utilization rate of about 98%. At such a high utilization rate, shifts away from expected normal levels of demand, either up or down, typically results in large short-term price movements to bring demand back into balance with supply. Natural gas–fired power generators face the risk of seasonal or shorter-duration natural gas price run-ups as well as brief episodes of days or weeks when natural gas prices spike at multiples of the normal price level.

Natural gas storage infrastructure provides some short-run capacity to manage unanticipated ups or downs in natural gas demand. However, natural gas storage involves a seasonal injection and withdrawal pattern that manages the inverse strong seasonality in aggregate consumer natural gas demand. As a result, using the flexibility of natural gas storage to manage short-run shocks to demand and supply alters the expected seasonal injection or withdrawal pattern. For example, US lower-48 storage inventories were nearly 1 Tcf below the five-year average inventory at the end of March 2014 following the polar vortex. As a result, the accumulation of short-run storage adjustments across a season can produce inventory surplus or deficit conditions that cause a ripple effect on natural gas prices until inventory levels return to normal, an adjustment process that can take a year or more.

The bottom line is that as PJM becomes more dependent on natural gas–fired generation, a risk exists in the short run that the expansion of natural gas supply—production, storage, and delivery—will not expand in sync with overall demand changes and short-run price variability will likely wax and wane in the years ahead.

The current risks in the power generation natural gas fuel supply chain led the US Department of Energy (DOE) to conclude, "Capacity challenges on existing pipelines combined with the difficulty in some areas of siting and constructing new natural gas pipelines, along with competing uses for natural gas such as for home heating, have created supply constraints in the past. Supply constraints can create increased price risk and, in extreme cases, could impact reliability."[10]

Fuel price and deliverability risks are not unique to natural gas. However, the current size of the PJM natural gas–fired generation share, and the dominance of natural gas–fired capacity in the PJM new electricity supply pipeline, focuses attention on increasing exposure to natural gas risk factors. Assessments of overall fuel supply risk factors indicate that price movements and deliverability constraints are not highly correlated across all fuels used to generate electricity.

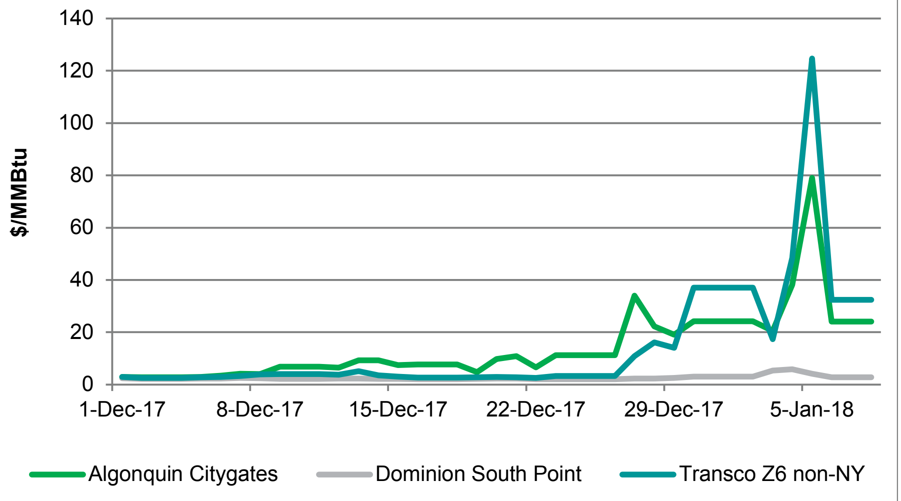
Efficient diversity in a power supply portfolio provides more stable and more predictable consumer monthly power bills because a diverse power supply portfolio mutes the impact of any single fuel price change on overall power system production costs. In addition, the cost-effective diversity of an efficient power supply portfolio also provides the capability to lower overall production costs by enabling the substitution away from more expensive generation and toward less expensive generating resources as relative generating costs change in the dispatch of supply to demand in real time. Consequently, efficient diversity in a power supply portfolio provides an inherent ability of grid-based power supply to withstand and reduce the magnitude and/or duration of disruptive events on grid-based power supply costs. As the National Academies of Sciences, Engineering, and Medicine notes, "Resilience is broader than reliability."[11] From this broader perspective, resilient grid-based power supply provides the capacity to reduce the magnitude of variations in the expected costs of electricity production.

Recent events illustrate how the uncertainty of fuel costs and the periodic changes in fuel deliverability constraints create hard-to-anticipate, real-time power production cost variability. During the 28 December 2017 to 7 January 2018 winter cold snap designated the "bomb cyclone" event, weather conditions caused a hard-to-predict and significant deviation from expected natural gas prices and delivery conditions.

The bomb cyclone event caused a spike in the delivered fuel costs of rival natural gas–fired PJM generators. Figure 6 shows that on

Figure 6

Average daily delivered price of natural gas to PJM power sector: 2017/18 winter



Source: IHS Markit, EIA

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10. Staff Report to the Secretary on Electricity Markets and Reliability, August 2017, US DOE.

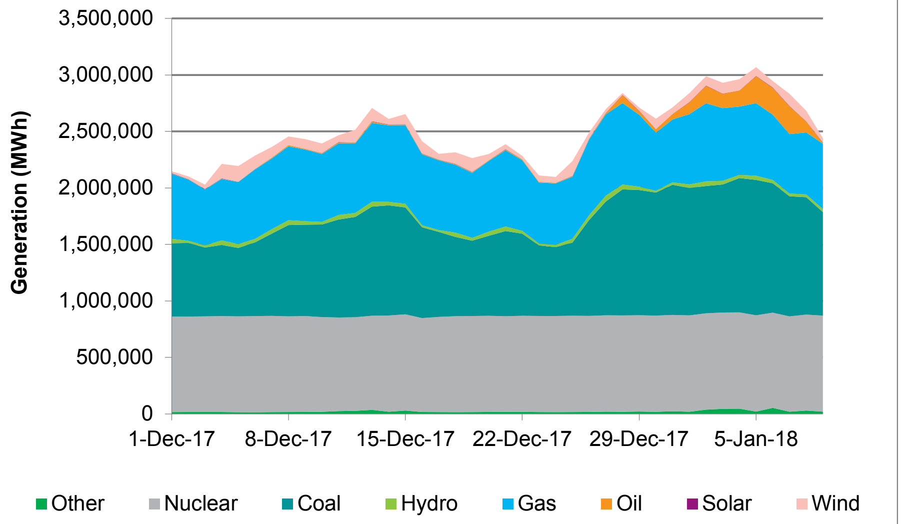
11. National Academies of Sciences, Engineering, and Medicine, *Enhancing the Resilience of the Nation's Electricity System, National Academies Press,* Washington, DC, 2017, p. 1, https://doi.org/10.17226/24836, retrieved 13 December 2017.

5 January 2018, the Transco Zone 6 non-NY spot price reached $124.7/MMBtu, representing a 40-fold increase from the average daily price in 2017 and a 35-fold increase from the average daily price in January 2017.

Natural gas–fired generation accounts for a minority of PJM generation output, but since natural gas–fired SRMCs disproportionately influence PJM market-clearing energy price levels, the delivered cost of natural gas price spikes caused the market-clearing hourly wholesale price of electricity in PJM to increase 20-fold, from an average of $29.4/MWh in 2017 to a peak of $586.40/MWh on 7 January 2018.

Figure 7

PJM generation by fuel type during 2017/18 bomb cyclone



Source: IHS Markit, PJM

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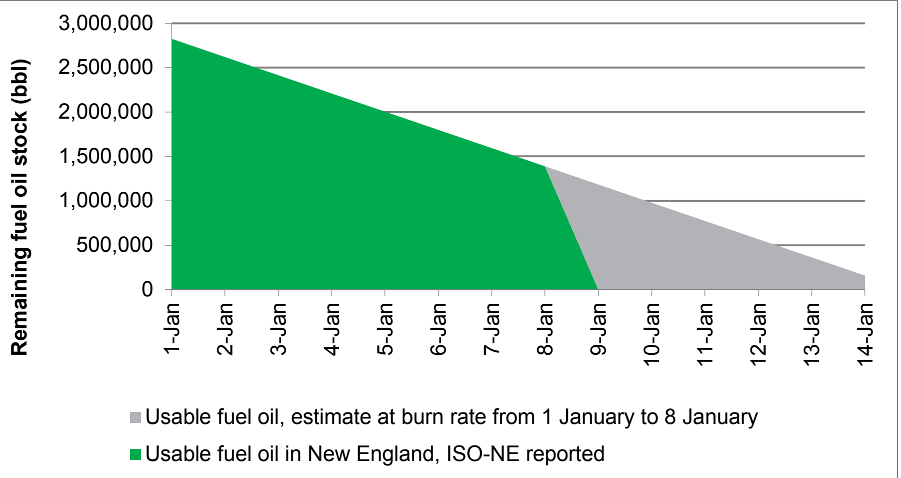
As Figure 7 shows, as the bomb cyclone unfolded, the natural gas–fired share of PJM electricity declined while generation shares increased from nuclear and other fossil resources, especially oil-fired capacity. This resilience in power supply and production costs was a direct result of the lack of correlation of risk factors among the diverse fuel and technologies employed in the current PJM generating portfolio.

During the bomb cyclone, oil-fired generation shares increased significantly, particularly in New England and other natural gas–constrained regions. The share of generation from oil-fired units exceeded 30% for six consecutive days in ISO New England (ISO-NE). This increase in generation shares from oil-fired units accelerated the depletion of on-site inventories of fuel oil. Over the course of one week, the total usable fuel oil for power generation in New England was depleted by about 50%. As shown in Figure 8, if burn rates had continued at a similar pace, without resupply, the region would have nearly fully depleted available fuel oil inventories in one week.[12]

Figure 8

Depletion of fuel oil stock at New England power plants, 1–8 January 2018 (actual); 9–14 January 2018 (estimate)



Note: Inputs account for no replenishment of fuel oil stock.
Source: IHS Markit, ISO-NE

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12. ISO-NE, *Cold Weather Operations: December 24, 2017–January 8, 2018*, 16 January 2018, https://www.iso-ne.com/static-assets/documents/2018/01/20180112_cold_weather_ops_npc.pdf, retrieved 2 March 2018.

In scenarios where nuclear capacity was unavailable, the region would have been even more fuel constrained. For example, if New England's nuclear power generating capacity had been retired and replaced by a combination of natural gas– and/or oil-fired generation, the region would have burned even more oil during the storm and left inventories completely or close to fully depleted.

Consumers reveal a preference for stable and predictable electricity costs. The deployment of advanced metering, communication, and control technologies across the past decade enabled a wide range of consumers the option to choose retail electricity prices that reflected real-time wholesale electricity marginal costs. These "time-of-use" retail pricing schemes involved less stable and less predictable electricity costs than traditional average cost–based retail pricing schemes. A minority of electric consumers, consisting primarily of large commercial and industrial users with flexibility regarding when they consume electricity, revealed a preference for real-time pricing schemes. By contrast, when most consumers were given the choice, they revealed a preference for the retail electricity prices with less variability and more predictability than the "time-of-use" prices.[13] The choices suggest that most electricity consumers are residential and small commercial consumers who typically do not have the flexibility to benefit from shifting electricity use through time in response to real-time price changes and, therefore, find little upside to choosing more variable real-time electricity pricing options. The bottom line is that most consumers reveal a preference for resilience in power supply costs.

Cost-effective nuclear generation shares in an efficient, diverse PJM power supply portfolio provide inherent electric production cost resilience. Since the production cost risks of nuclear plants are not highly correlated to risks associated with nonnuclear fuels and generating technologies, the nuclear generation in the PJM power supply portfolio makes power production costs more stable and less variable compared with the production costs of the current PJM replacement power resource mix. Since cost-effective nuclear generation in the PJM supply portfolio provides consumers with inherent electric production cost resilience, this resilience comes at zero cost to consumers.

The bottom line is that if the uneconomic PJM nuclear capacity closure and replacement results in less production cost resilience, then consumers face more varied and less predictable monthly electricity bills unless other mechanisms, such as financial hedging instruments, are employed to restore the production cost resilience lost due to premature nuclear power plant closures. Since these other production cost risk mitigation options are more expensive, a balancing of the costs and benefits of production cost risk management results in higher costs and a lower expected level of production cost resilience.

Public policies harmonized with wholesale market operations can meet consumer preferences for cost-effective resilience in electric availability and production costs

Alignment of government policies with a well-structured electricity market design is necessary for efficient market outcomes. Addressing resilience challenges does not involve choosing between markets and regulation to organize and coordinate electric system operations. Instead, the resilience issue shows that efficient electricity market outcomes are not possible without enabling government involvement and policy and market harmonization. The importance of public policy and market harmonization is often underappreciated because many fundamental government market interventions for efficient market operations are taken for granted. For example, court systems enable electricity market interactions by providing the mechanisms to make electricity market transactions enforceable, and government regulations setting the financial disclosure requirements and accounting standards for companies enable efficient market allocation of capital to electric

13. See the IHS Markit Multiclient Study *The "Smart Grid Narrative" and the "Smarter Grid": Revolution versus Evolution—Which Way Forward?*

Regulatory market interventions*

The market model benchmark:

The main body of microeconomic theory can be interpreted as describing how, under proper conditions, an unregulated 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.

*Alfred E. Kahn, *The Economics of Regulation: Principles and Institutions,* vol. 1, MIT Press, Cambridge, Massachusetts, 1998 (original publication 1970), pp. 11 and 17.

infrastructure investments. The bottom line is that federal oversight and ongoing adjustments of regional reliability standards and wholesale electricity market rules and institutions are necessary to enable efficient electricity market operations.

Alfred Kahn wrote the textbook on government regulation and established the principle that government involvement in the marketplace needs to enable effective competition (see the box “Regulatory market interventions”).

From this perspective, effective wholesale electricity market competition involves a coordinated mix of competitive forces and regulatory processes that produce the timely price signals to govern the engineering and economic trade-offs that shape a diverse mix of fuels and technologies that cost-effectively align with the recurring annual hourly pattern of aggregate consumer demand, and allow for the efficient utilization of available resources, subject to the security of supply constraints in an AC power system. These conditions produce a well-functioning electricity market capable of reliably balancing power system demand and supply—in both the short and long run—to provide the electric services that consumers want, whenever they want them, at a price that internalizes all costs. Appendix B outlines the characteristics of an efficient wholesale electric market outcome.

Consumer demands for affordable electricity require achieving the lowest overall cost of the security-constrained economic dispatch of electric supply by harmonizing public policies and market operations to meet consumer demands. Enabling public policies can produce effective competition only by insuring that similarly situated rival generators are treated equally and that all costs are counted in the marginal cost–based competition.

Consumer demands for reliable electricity require harmonizing public policies and market operations to ensure effective competition yields a capacity price that complements the market-clearing electric energy price to provide a timely investment signal that maintains a capacity reserve that delivers a loss of load probability that balances the costs and benefits of incremental losses of load.

Consumer demands for resilient production costs require harmonizing public policies and market operations to ensure effective competition generates capacity and energy prices that drive each supply resource to balance the costs and benefits of investments providing cost and operating resilience to the specific fuel and technology risk factors. Since the risk factors associated with each fuel and technology pairing have weakly correlated risk factors, harmonized public policies and market operations also shape an efficient mix of fuels and technologies whose cost-effective diversity provides inherent resilience in overall power production costs to mitigate the potential impact of significant deviations from normal operating conditions.

Environmental responsibility requires harmonization of public policies and market operations to enable efficient trade-offs of environmental costs and benefits. Such trade-offs ensure that investments to reduce CO_2 emissions deliver the greatest bang for the buck.

The bottom line is that an efficient market outcome provides a benchmark to access market outcomes distorted by the unequal treatment of similarly situated rival generators. Appendix C describes the predictable market distortions that arise under these conditions.

A loss of resilience due to uneconomic PJM nuclear closures is a plausible scenario

Costly premature PJM nuclear power plant closures present a plausible scenario. Such a scenario is already unfolding in other US power systems where the discord between public policy initiatives and wholesale market operations has already contributed to the premature closure of six nuclear plants in the past eight years and announced plans for eight more in the next eight years (see Figure 9). The recent FirstEnergy Solutions announcement of the premature deactivation of more than 4,000 MW of PJM nuclear resources is the leading edge of the potential rapid loss of PJM nuclear resources. The potential consequences of rapid, premature PJM nuclear closures on power system reliability, resilience, costs, and CO_2 emissions are apparent from experiences in other power systems.

Figure 9

Nuclear plant proposed and completed closures since 2012

Source: IHS Markit/ 1713785

The consequences of unresolved discord between public policies and California Independent System Operator (CAISO) market operations is a harbinger for other power systems, including PJM. Market distortions contributed to the decisions within a span of three years to close and replace all four nuclear units and drive the in-state generation share of nuclear resources from 18% to zero within a dozen years. The lack of harmony has already caused the in-state nuclear generation share to decline from 18% to 10% in the five years from 2012 to 2016, and announced premature nuclear closures will eliminate nuclear generation in California by 2025. The consequences of the closure and replacement of nuclear capacity and energy in California already include

- **Costly capacity and energy replacement.** The replacement of nuclear capacity and generation outputs with more expensive wind, solar, and natural gas–fired resources caused California power price increases to outpace US average retail electricity price changes and pushed the California average retail electricity price in 2016 to a 50% premium to the US average.

- **CO_2 emission boomerang.** The replacement of California nuclear generation with renewable resources integrated by natural gas–fired resources to back up and fill in for the intermittent output patterns shifted most of the in-state generation to fossil fueled resources. The associated rebound in CO_2 emissions resulted in California electric generation CO_2 emission levels remaining the same in 2016 as the levels observed 15 years ago when California legislation mandated the first renewable power generation shares. As a result, California did not make an environmentally responsible trade-off of higher costs in exchange for lower CO_2 emissions.

- **Ad hoc market interventions to address unresolved market distortions.** The interventions arose to create compensation for selected generation attributes. In 2013, CAISO recognized that the suppression of CAISO wholesale market-clearing prices caused a cash flow shortfall for the continued operation of generation resources required for reliable electric supply. As a result, CAISO implemented market interventions in 2014 to augment energy market cash flows for flexible generation resources needed to back up and fill in for mandated intermittent resources by implementing ramping products to provide out-of-market payments for these selected attributes.

- **Reduction in power supply resilience.** This reduction is due to the increased exposure to natural gas supply risk factors associated with the greater reliance on natural gas in the generation portfolio. The Aliso Canyon natural gas storage outage discovered in 2015 constrained fuel deliveries and forced the in-state generation share for natural gas to decline from 61% to 50% from 2014 to 2016.

- **Inefficient market operations.** The inefficiencies involve larger cost burdens associated with managing overgeneration market conditions reflecting the mismatch between intermittent generation and aggregate consumer demands. The inefficiency results in higher costs from increasing renewable power curtailments and growing Energy Imbalance Market sales at prices well below what California consumers had to pay for the renewables.

- **Lower consumer net benefits.** Higher electricity prices and the associated consumer demand reductions lowered the annual California consumer net benefit from electricity consumption.

The bottom line is that decisions to prematurely close nuclear power plants and reduce the PJM nuclear generation share of firm capacity from 20% to zero within a dozen years is a plausible scenario because PJM could follow the example of California. In California, persistent, unresolved discord between public policies and market operations is eroding the consumer net benefits from electricity consumption, as well as the resiliency and environmental responsibility of power supply coming from nuclear resources.

The analytical framework to assess the potential impact of uneconomic nuclear closures in the PJM power supply portfolio

Assessing the current value of nuclear generation in the PJM power supply portfolio involves the comparison of the performance of the PJM power supply portfolio with and without nuclear resources.

This assessment of the value of current nuclear resources evaluates alternative PJM power supply portfolio performance using a backcasting analysis across the most recent four years (2013 to 2016) to analyze the impacts of uneconomic PJM nuclear power plant closures. A backcasting approach uses the range and severity of deviations from expected normal operating conditions in the recent past to provide a realistic "wind tunnel" to test how the loss of PJM nuclear capacity affects overall power system production costs, as well as assess how nuclear power in the supply portfolio affects the resilience of PJM outcomes to a realistic profile of instability and deviations from normal operating conditions.

A forecasting approach can also incorporate a realistic risk profile through sensitivity analyses of forecast simulations. However, forward-looking sensitivity analyses need to foresee the risk profile of the power system operating environment. As the National Academies of Sciences, Engineering, and Medicine study notes, resiliency involves assessing how robust power systems operations are to disruptions, including those that may not be foreseen.[14]

Besides the possibility of unforeseen risks, behavioral economists observe that most people view themselves, the world, and the future in a considerably more positive light than is objectively justified or than reality can sustain.[15] Therefore, employing a forecasting approach creates the risk of bias toward underestimating the risk profile of future electric system operating conditions. To see this, imagine a PJM forecast sensitivity analysis developed four years ago that included the 2014 polar vortex episode, no PJM load growth, Hurricane Sandy (second-most destructive storm in US history), the demise of the Clean Power Plan, and daily delivered natural gas prices ranging from $0.5/MMBtu to $121.2/MMBtu. Building a consensus that this scenario represented a realistic risk profile would have been difficult because of the perception that these events occurring over a four-year interval was unrealistic. Yet experience shows that this is exactly what happened as the years unfolded.

Experience shows that deviations from expected normal electric system operating conditions are inevitable. The implication is evident in a recent PJM market assessment concluding that, "Relying too heavily on any one fuel type may create a fuel security or resilience issue .... But, a moderate level of diversity helps to ensure the system's ability to withstand unforeseen system shocks—either operational disturbances caused by contingencies beyond those studied and planned for today or both man-made and natural disasters".[16]

Looking ahead for several decades, the low-probability but high-impact events that caused past deviations from normal operating conditions will no doubt differ from the risk factors that trigger future deviations from expected operating conditions. The probability of another polar vortex episode like 2014 or the bomb cyclone event in 2017/18 may be 1 in 10 years or less. Such a low probability of recurrence can lead to complacency regarding power supply resilience. Similarly, the probability of another hurricane like Sandy in 2012 hitting New Jersey may also be 1 in 10 years or less. Likewise, the probability of another pipeline disruption such as the 2016 Texas Eastern pipeline disruption in Pennsylvania may also be 1 in 10 years. Other potential low-

14. National Academies of Sciences, Engineering, and Medicine, *Enhancing the Resilience of the Nation's Electricity System,* National Academies Press, Washington, DC, 2017, p. 1, https://doi.org/10.17226/24836, retrieved 13 December 2017.

15. Max Bazerman and Michael Watkins, *Predictable Surprises: The Disasters You Should Have Seen Coming, and How to Prevent Them,* Harvard Business School Publishing Corporation, Boston, Massachusetts, 2004.

16. PJM, PJM's *Evolving Resource Mix and System Reliability,* March 2017, http://www.pjm.com/-/media/library/reports-notices/special-reports/20170330-pjms-evolving-resource-mix-and-system-reliability.ashx, retrieved 21 February 2018.

probability but high-impact deviations from normal operating conditions include a natural gas storage failure like what recently happened at the Aliso Canyon natural gas storage facility in 2014, as well as wildfires, heat waves, droughts, and physical or cyber attacks.

Political risks also define a dimension of the electric operating risk profile. For example, the growing anti–fossil fuel movement is delaying the development of the natural gas supply infrastructure to keep pace with the increased supply requirements of the electricity sector. Such political risks can shift the power production operating environment suddenly.

The consequences of these risk factors can increase when two or more high-impact events occur simultaneously. For example, the risk of a severe seismic event associated with hydraulic fracturing wastewater injections somewhere in United States could interact with the risk of a political overaction. Such an interaction could produce a ban on hydraulic fracturing for natural gas production everywhere, including the Marcellus natural gas fields that supply a significant portion of natural gas for electric generation in PJM. Even if such a ban were temporary, the price and deliverability of natural gas in PJM would likely be dramatically affected for months.

Although the probability of any one of the risk factors happening in any given year is low, the probability of some type of high-impact event that challenges electric system resilience is much higher because the probability of at least one of these events happening is the sum of the probabilities of each of these independent risk factors.

The bottom line is that prudent planning ought to account for a better-than-even chance that a major disruptive event affecting the availability of one type of electric generating resource in the PJM supply portfolio will occur within the next decade.

The backcasting approach helps to address the problem of risk blind spots and risk underestimation by providing a realistic set of significant deviations from expected conditions.

Assessing the potential impacts of uneconomic nuclear closures in the PJM power supply portfolio

Quantifying the impact of uneconomic retirement and replacement of PJM nuclear power plants involves four steps:

- Estimating PJM nuclear resource going-forward costs
- Estimating the cost of generating technologies in the current PJM new supply pipeline capable of providing equivalent capacity and energy outputs as provided by PJM nuclear resources
- Identifying the market inefficiency—retiring power plants that are lower cost to continue to operate than to replace
- Quantifying market inefficiency by estimating counterfactual outcomes from 2013 to 2016 for the PJM nuclear retirement and replacement scenario

PJM nuclear going-forward costs

PJM nuclear power plants account for 34% of the US installed nuclear fleet. Table 5 shows US nuclear power plant going-forward cost assessments from the Nuclear Energy Institute (NEI) differentiated by single-plant and multiplant sites.[17] The nuclear going-forward cost represents the average going-forward cost for existing nuclear power plants. The going-forward costs for a particular existing nuclear power plant will differ from the average owing to a variety of factors including different operating and market risk factors.

Table 5

Levelized going-forward costs of existing US power supply portfolio resources, 2016
($/MWh)

Plant type	Levelized cost
Single-unit nuclear plant	41.4
Multiunit nuclear plant	31.6
Average nuclear plant	33.9

Source: IHS Markit, NEI © 2018 IHS Markit

PJM new supply pipeline technology cost and performance profiles

The current PJM new capacity supply pipeline is composed of 85% natural gas–fired generating technologies and 15% renewable resources. Consequently, the replacement of the capacity and energy of uneconomic PJM nuclear power plant closures would likely involve a similar mix of technologies.

The cost and performance characteristics of the mix of grid-connected electric generating technologies in the PJM new supply pipeline reflect the EIA cost and performance profiles reported in the Annual Energy Outlook 2016, shown in Table 6 with adjustments to heat rates based on observed heat rates of new generating resources operating in PJM. The size of each generating technology option reflects expected current minimum efficient scale.

The operating lifetime technology parameter 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 MACRS 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 wind overnight costs include a transmission investment adder to reflect the incremental grid investment associated with the project interconnection to the network.[18] 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 to load centers. The transmission cost adder in the Electric Reliability Council of Texas was $600/kW of

Table 6

Electric generating technology cost and performance characteristics in PJM

Technology	Size (MW)	Lifetime/ MACRS (years)	Overnight costs (2017$/kW)	Lead time (years/ CFUDC)	Contingency factor	Variable nonfuel O&M (2017$/MWh)	Fixed O&M (2017$/kW-year)	Heat rate (Btu/kWh)
Wind	100	20/7	$1,548	1/1.07	1.07	$0.0	47.5	
Solar PV, with tracking	150	20/5	$2,004	1/1.07	1.05	$0.0	22.0	
Natural gas–fired combined cycle	429	30/20	$1,026	3/1.15	1.08	$4.0	10.1	7,010

Note: MACRS = modified accelerated cost recovery system; CFUDC = cost of funds used during construction; O&M = operations and maintenance.
Source: IHS Markit, EIA © 2018 IHS Markit

17. NEI, *Nuclear Energy 2016: Status and Outlook, Annual Briefing for the Financial Community,* 11 February 2016.

18. Estimates of typical incremental transmission investments are based on Andrew D. Mills, Ryan H. Wiser, and Kevin Porter, *The Cost of Transmission for Wind Energy: A Review of Transmission Planning Studies,* Lawrence Berkeley National Laboratory, 2009, https://emp.lbl.gov/publications/cost-transmission-wind-energy-review, retrieved 27 March 2018; 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.

installed wind capacity. An estimate of the incremental transmission investment needed to upgrade the current system capabilities as well as build 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.[19]

The lead time is the number of years required for project construction. The CFUDC 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 costs exclude fuel costs. Fixed O&M costs 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. This cost analysis employs a higher heat rate than reported in the EIA Annual Energy Outlook 2016. The EIA heat rate reflects thermal efficiency levels of equipment manufacturer performance specifications that typically express heat rates based on fuel inputs that count only the British thermal units that were converted into electric energy. In the thermal electric generation process, some of the British thermal unit content of the fuel input vaporizes the moisture present in the combustion process, and, as a result, this heat content is not converted into electricity. By contrast, a fuel input that accounts for all British thermal units involved in the electric generation process has a heating value that is higher by about 11%.

This analysis uses a heat rate reflecting all British thermal units consumed in the generation process. Since the prices of fuel inputs for power generation reflect the cost of the total British thermal unit content of the fuel expressed in a dollars per million British thermal units basis, the higher heat rate provides the appropriate transformation of fuel input cost to cents per kilowatt-hour fuel generating cost. The difference between higher and lower heating values explains the 11% difference between the actual average heat rates of new natural gas–fired combined-cycle generating technologies shown in Table 7 and the heat rate specification appearing in cost and performance characteristics of new central station natural gas–fired generating technology specifications of the EIA Annual Energy Outlook 2016.

The variation of heat rates around the capacity-weighted average shown in Table 7 reflect differences in operating conditions affecting the new natural gas–fired combined-cycle power plant heat rates that include altitude, humidity, and ambient air temperature. As a result, the actual operating experience of a new natural gas–fired generator is not as favorable as the equipment manufacturer's generating technology specifications that typically reflect more stable and favorable operating conditions of sea level altitude, 59 degrees Fahrenheit ambient air temperature, and 60% relative humidity.

EIA reports the average realized natural gas–fired power plant heat rate in 2016 was 7,878 Btu/kWh. This indicates that new natural gas–fired combined-cycle power plants operating under actual conditions have a thermal efficiency that is about 11% lower than the average thermal efficiency of installed natural gas–fired generation.

19. Renewable Energy Transmission Initiative 2.0—Transmission Technical Input Group, *Transmission Capability and Requirements Report,* 24 October 2016, http://docketpublic.energy.ca.gov/PublicDocuments/15-RETI-02/TN214168_20161025T091645_Transmission_Capability_and_Requirements_Report.pdf, retrieved 27 March 2018; and Edison Electric Institute, *Transmission Projects at a Glance,* December 2016, p. vii, http://www.eei.org/issuesandpolicy/transmission/Pages/transmissionprojectsat.aspx, retrieved 27 March 2018.

Table 7

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

Source: IHS Markit, EIA

Common cost parameters for power plant development are shown in Table 8.

The fuel input costs for replacement natural gas–fired generating technologies reflect the recent PJM average delivered cost of natural gas for the electric power industry (see Table 9).

Table 8

Common cost parameters for power plant development	
Input	Value
Cost of equity	10.5%
Cost of debt	6.3%
Inflation rate	2.0%
Share of debt	60%
Federal tax rate	21.0%
State tax rate	7.0%

Source: IHS Markit

Table 9

PJM average delivered cost of natural gas for the electric power industry		
Year	Trillion Btu	$/MMBtu
2013	1,071	4.2
2014	1,128	5.0
2015	1,457	2.7
2016	1,682	2.2
Weighted average, 2013–16		**3.3**

Source: IHS Markit, EIA

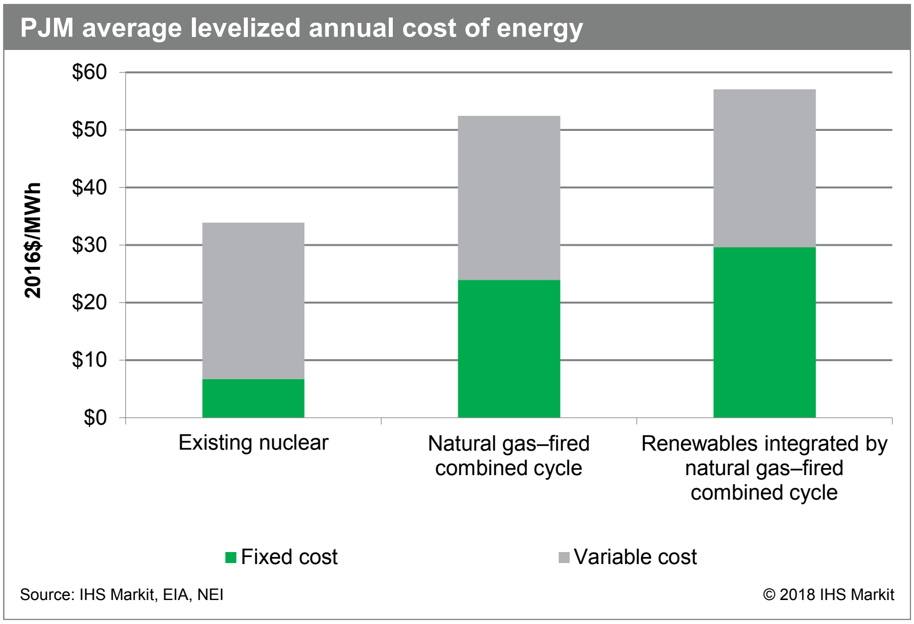
Identifying market inefficiency

Capacity and energy price signals from an unfettered, efficient market would not cause generating resources to close if their cost of continued operation was lower than the cost of their replacement. Cost-effective power plant retirements occur in a well-functioning marketplace because market-clearing prices reflect the long-run marginal costs (LRMCs) of new power resources and thus provide a signal regarding the cost-effective timing for replacing existing generation. As a result, in an efficient market outcome, an existing resource is economic to operate until the existing resource going-forward costs are not covered by market cash flows reflecting the cost of replacement supply.

PJM nuclear generating plants' going-forward costs are significantly below replacement costs. Figure 10 shows the differences between average going-forward costs for PJM nuclear resources to supply the stable 24/7 base-load segment of PJM consumer demand and the cost of replacement capacity and energy from natural gas–fired combined cycles integrated with a mix of intermittent wind and solar resources in the proportions found in the current PJM new power supply development pipeline.

Analyses show that the going-forward costs of nuclear plants increase by less than 1% per year over the observed age distribution of existing plants.[20] Therefore, the existing gaps between the going-forward costs of existing nuclear resources and replacement costs appear persistent.

Figure 10



The bottom line is that premature PJM nuclear power plant retirements are uneconomic because continued operation is less costly than closure and replacement. As a result, an efficient PJM wholesale market outcome would not likely involve premature nuclear power plant closures. The result is not unique to PJM. Analyses of the US electrical interconnection absent the distortions of wind and solar subsidies and mandates, and incorporating an appropriate CO_2 emission charge, indicate that the premature retirement of nuclear power plants—with typical going-forward costs—would be highly unlikely on economic grounds.[21]

Counterfactual outcomes in 2013–16 for the PJM nuclear retirement and replacement scenario

Backcasting PJM demand and supply interactions at a monthly frequency for 2013–16 with the removal of the Oyster Creek nuclear power plant provides a backcasting base case for the PJM nuclear closure and replacement scenario. The base case removes Oyster Creek because its closure is not in doubt. The PJM nuclear power plant closure and replacement scenario involves the closure and replacement of all remaining 18 PJM nuclear units. Table 10 shows differences between the PJM backcasting base case and the PJM nuclear closure and replacement scenario.

The PJM nuclear closure and replacement scenario results in higher power production costs and thus higher retail power price levels compared with the PJM base case. The retail price increases are greatest in 2013–14, when the delivered price of natural gas to electric generators averaged $4.6/MMBtu, compared with 2015–16, when the delivered price of natural gas averaged $2.4/MMBtu.

20. Thomas F. Stacy and George S. Taylor, *The Levelized Cost of Electricity from Existing Generating Resources,* Institute for Energy Research, June 2015, http://instituteforenergyresearch.org/wp-content/uploads/2015/06/ier_lcoe_2015.pdf, retrieved 27 March 2018.

21. Lawrence Makovich, *Tilting at Windmills: Making a case for reframing electric sector climate policies,* Mossavar-Rahmani Center for Business and Government Associate Working Paper No. 78, June 2017, https://www.hks.harvard.edu/centers/mrcbg/publications/awp/awp78, retrieved 27 March 2018.

Table 10

PJM nuclear scenario, 2013–16
(billion dollars, 2016)

Calculations	2016	2015	2014	2013	2013–16
Increase in variable costs	3.0	3.9	9.0	7.0	5.7
Increase in fixed going-forward costs	3.2	3.7	3.8	3.8	3.6
Total production cost increase	6.2	7.7	12.7	10.8	9.3
PJM base retail sales (TWh)	664	664	663	660	
PJM base average real retail price (cents per kWh)	10.4	10.6	10.5	10.4	
Total base retail revenues	68.8	70.2	69.9	68.5	
Increase in average real retail electricity price (percent)	9%	11%	18%	16%	13%
Increase in monthly production cost standard deviation (percent)					53%

Source: IHS Markit, EIA

Consumer cost impacts from uneconomic PJM nuclear retirements

Higher production costs and higher retail power prices have a negative impact on electricity consumers who rely on PJM grid-based electricity supply.

A useful metric to assess consumer impacts from the electricity price increases expected from uneconomic PJM nuclear power plant closures is the change in consumer net benefits from electricity consumption. This metric provides a better indication of consumer impacts from higher retail prices than assessments based on the change in the consumer monthly power bill. For example, if the price of electricity increased by 50% and consumers responded by reducing their consumption by 50%, then their monthly power bill remains unchanged. However, although the power bill did not change, the consumer is worse off. Employing an assessment of the change in net benefit from electricity consumption can measure economic impact on the consumer while accounting for price-induced consumer reductions in consumption.

Figure 11 show the changes in retail electricity prices estimated by the difference between the base and alternative cases of the PJM nuclear closure and replacement scenario in 2016. The figure also shows the expected PJM consumer reduction in demand due to the higher prices and the associated change in the net benefit from electricity consumption.

Table 11 shows the estimates of the loss in PJM consumer net benefits of electricity consumption in the PJM nuclear closure and replacement scenario for the power system from the baskcasting analyses with power system conditions reflecting actual conditions in 2013–16.

The bottom line is that the uneconomic retirement and replacement of PJM nuclear power plants reduces the consumer annual net benefit from PJM grid-based electricity by about $8 billion per year over 2013–16. This translates into a consumer net benefit per kilowatt-hour of PJM nuclear generation of about 3 cents per kWh.

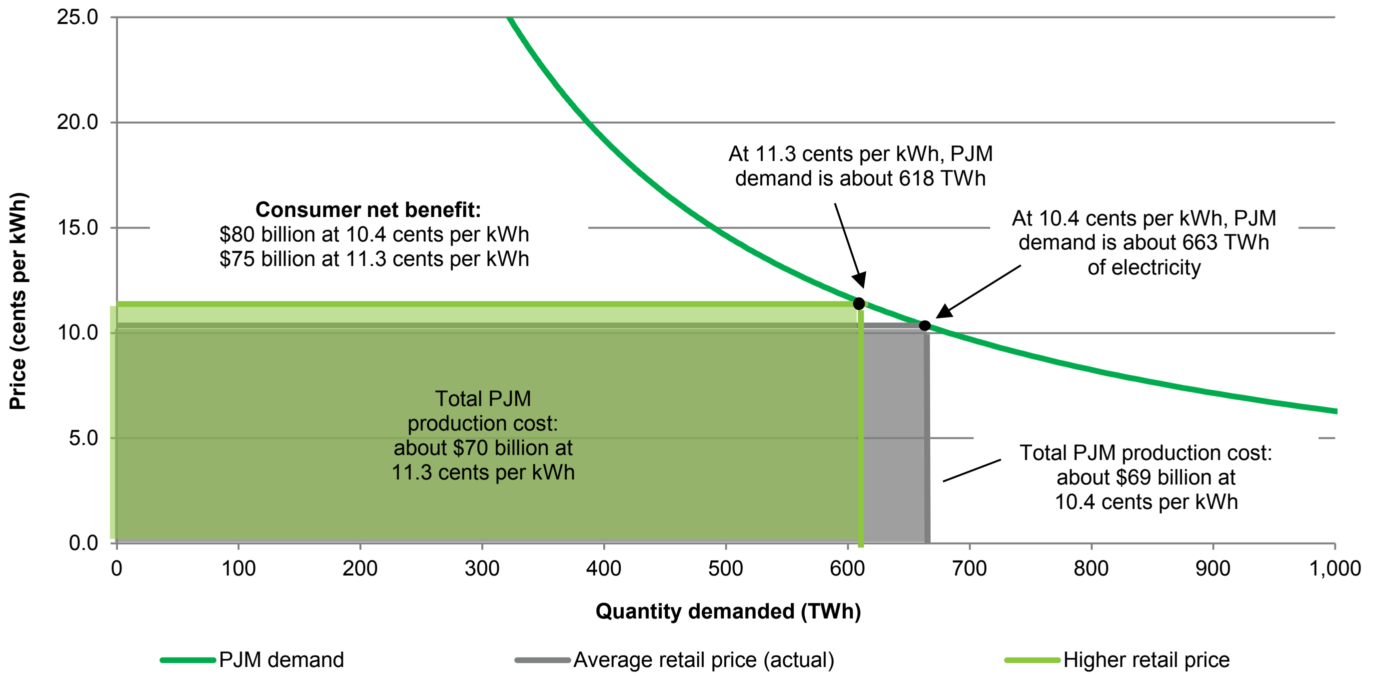
Production cost resilience impacts from uneconomic PJM nuclear retirements

The PJM nuclear closure and replacement scenario results in an increased reliance on natural gas–fired generation resources and the associated increased exposure to natural gas price variation. Backcasting the PJM nuclear closure and replacement scenario across 2013–16 results in a more than doubling of the monthly variation in PJM overall production costs (as measured by the standard deviation of PJM production costs).

PJM market distortions that cause uneconomic base-load power plant retirements accelerate the move toward a natural gas–fired generation share beyond the cost-effective share expected in an unfettered, efficient market outcome. Therefore, natural gas–fired generation risks—short-run price variability, long-run

Figure 11

PJM grid-based electricity demand (long run): 2016, impact of an approximate 9% price increase



Source: IHS Markit

multiyear price cycles, physical limits to deliverability, and political uncertainties—become an increasing long-run concern in PJM.

Table 11

PJM consumer net benefits—Actual versus higher prices, 2013–16
(billion dollars, 2016)

	Total retail electricity supply cost			Total consumer net benefit		
Year	Base case	Nuclear scenario	Difference	Base case	Nuclear scenario	Difference
2016	68.7	69.8	1.1	80.5	74.6	-5.9
2015	69.3	70.6	1.3	78.3	73.1	-5.2
2014	68.3	70.3	2.0	80.0	68.4	-11.6
2013	65.7	67.4	1.7	79.6	70.3	-9.4

Source: IHS Markit, EIA

The cost of replacing PJM nuclear production cost resilience

The diversity provided by cost-effective nuclear energy reduces the exposure of electric production costs to natural gas price variation. An estimate of the value of this production cost risk management provided by current PJM nuclear resources is available from another backcasting assessment in which the PJM nuclear closure and replacement scenario is altered to allow for the purchase of financial instruments—natural gas futures and options—to restore the base-case level of monthly production cost variation.

Hedging natural gas prices provides an alternative approach to limiting the impact of natural gas price variation on overall PJM electric production cost variation. A simple hedging strategy could employ natural gas call options. Purchasing a natural gas call option provides the holder with the right, but not the obligation, to purchase a specified amount of natural gas at a specified price and at a specified future point in time. Appendix D provides an example of applying this approach to create a rolling month-ahead call option on the delivered price of natural gas in PJM across 2013–16, employing a strike price set to limit the price paid for natural gas to the current delivered price of natural gas. The option cost assessment employs a variant of the Black-Scholes option pricing formula to estimate the cost of reducing the variability of the delivered price of natural gas in PJM with this hedging strategy.

In the nuclear closure and replacement scenario, hedging PJM natural gas prices across 2013–16 with natural gas call options involves an average annual cost of $14 million to reduce the monthly variability of PJM cost of production by 1%. Because the production cost variability in PJM is 53% higher in the nuclear closure and replacement scenario, the annual cost to use natural gas call options to achieve the same level of production cost variability found in the PJM base case is $714 million. Note that this cost reduces the price risk of natural gas inputs for electric generation in PJM but does not reduce the physical deliverability risks of natural gas.

The bottom line is that the uneconomic retirement and replacement of PJM nuclear power plants increases the variation of PJM production costs, and restoring this cost resilience for consumers requires employing natural gas hedging mechanisms with an annual cost of $714 million. This translates into a consumer production cost resilience benefit per kilowatt-hour of PJM nuclear generation of about 0.3 cents per kWh.

PJM environmental impacts from uneconomic nuclear closures and replacement

The uneconomic closure of nuclear power plants in PJM due to market distortions would likely produce a power sector CO_2 emission increase. Uneconomic closures of power plants serving the base-load segment of aggregate consumer demand can increase CO_2 emissions when the replacement power resources are intermittent renewables integrated by natural gas–fired power plants. Table 12 shows the CO_2 intensity of the PJM replacement energy in the PJM nuclear closure and replacement scenario.

Table 12

Electric generation CO_2 emission intensity

	Capacity (MW)	Capacity factor	Generation (MWh)	Emissions factor (lbs/MWh)	Emissions (metric tons)
Typical nuclear power plant	1,600	93.0%	13,034,880	0	0
Total	**1,600**	**93%**	**13,034,880**	**0**	**0**
Wind—15%	797	28%	1,955,232	0	0
Natural gas combined cycle—85%	2,040	62%	11,079,648	1,003	5,040,727
Total	**2,837**	**52%**	**13,034,880**	**853**	**5,040,727**

Source: IHS Markit © 2018 IHS Markit

Closure and replacement of the non–CO_2-emitting PJM nuclear resources would remove 12 times the current output of PJM wind and solar resources.[22] To put this into perspective, there is approximately one vehicle for every two people in the United States, and therefore the 65 million people who rely on PJM grid-based power supply drive about 32.5 million vehicles.[23] The typical US vehicle emits 4.6 metric tons of CO_2 per year.[24] Therefore, the annual CO_2 emission increase expected from the uneconomic closure and replacement of PJM nuclear resources would equal the annual CO_2 emissions from two-thirds of the vehicles on the road in PJM.

Uneconomic closures of PJM nuclear power plants would likely create a CO_2 emission boomerang like the one observed in the New England power system. A lack of harmonization between electric sector policy implementation and ISO-NE market operations involves renewable mandates suppressing cash flows and causing the uneconomic closure of nuclear capacity. The closure of the Vermont Yankee Nuclear Power Corp.

22. Monitoring Analytics, LLC, *State of the Market Report for PJM (2017)*, 8 March 2018, p. 111 http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2017/2017-som-pjm-volume2.pdf, retrieved 10 April 2018.

23. "US States By Vehicles Per Capita," World Atlas, https://www.worldatlas.com/articles/us-states-by-vehicles-per-capita.html, retrieved 11 April 2018.

24. US Environmental Protection Agency, Office of Transportation and Air Quality, EPA-420-F-18-008, March 2018, https://www.epa.gov/sites/production/files/2018-04/documents/420f18008.pdf, retrieved 11 April 2018.

nuclear power plant occurred at the end of 2014 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 combined-cycle plants making up the replacement power sources. This premature nuclear power plant closure caused ISO-NE 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 upward impact on the regional electricity sector CO_2 emission level.

A PJM CO_2 boomerang is not environmentally responsible because it does not involve an efficient trade-off of higher costs in exchange for lower CO_2 emission levels. By contrast, an efficient CO_2 abatement initiative would achieve any CO_2 emission target by exploiting the lowest-cost options. Since the cost of continued PJM nuclear operation is lower than the cost of closure and replacement, continued nuclear operation provides a zero-cost option to reduce CO_2 emissions compared with offsetting the emissions associated with largely natural gas–fired replacement generation. Making such an offset by ratcheting up renewable mandates would be inefficient because the implicit cost of CO_2 reduction in PJM associated with policy-driven renewable resource development is about $220 per metric ton of CO_2 abatement.

Electric consumers reveal a preference for environmentally responsible power supply. Green power programs respond to this preference by offering more expensive renewable power options to satisfy the revealed preferences of consumers to do something about climate by limiting the CO_2 emissions associated with electricity production.

In 2016, consumers voluntarily chose to purchase 95 TWh of green power, representing 1.7% of total US retail electric energy sales. The highest customer participation rate in a utility voluntary green power program in 2016 was 17% in Portland General Electric's "Green Source" program, where consumers paid a 6.8% retail price premium.[25]

Since electricity consumers choose to purchase some, but not all, of their electricity at a green premium price, they reveal an underlying consumer preference to balance the costs and benefits of renewable power. At first blush, US consumers do not appear to be willing to pay much of a premium for renewable power, nor do they appear to be willing to purchase a large percentage of their supply from the higher-cost renewable resources.

Consumer choices for renewable power are likely suppressed by existing public policies that do not rely on voluntary individual consumer choice and instead mandate renewable generation shares and stimulate renewable development by socializing green power costs through subsidies and rate structures. Opinions vary regarding whether the politically determined level of renewable resources approximates the level expected from the aggregation of individual voluntary choices in an unfettered, efficient marketplace. However, politically determined renewable generation share mandates are like voluntary consumer choices because both typically limit renewable generation shares below 100% of supply. The implication is that politically determined collective decisions regarding renewable generation reveal an underlying trade-off between the political costs and benefits of increasing renewable generation shares.

The bottom line is that both individual consumer or collective political decisions regarding renewable generation shares reveal an underlying preference to balance the costs and benefits of increasing renewable generation in the power supply portfolio. Since environmental responsibility involves balancing environmental costs and benefits, the implication is that if premature PJM nuclear closures increase electricity costs while also increasing CO_2 emissions associated with PJM electricity production, then no trade-off is being made between environmental costs and benefits and, therefore, the outcome is less environmentally responsible.

25. Eric O'Shaughnessy, Jenny Heeter, Jeff Cook, and Christina Volpi, *Status and Trends in the U.S. Voluntary Green Power Market (2016 Data),* National Renewable Energy Laboratory, https://www.nrel.gov/docs/fy18osti/70174.pdf, retrieved 20 February 2018.

An assessment of the higher costs associated with developing mandated wind and solar development rather than the least-cost natural gas–fired combined-cycle alternative provides the basis to calculate the implicit cost of CO_2 reduction from policies that mandate wind and solar development rather than allow the market-driven development of natural gas–fired resources.

The cost of replacing PJM nuclear generation with natural gas–fired resources alone is about $52/MWh. Replacement with 15% of the generation coming from unsubsidized wind along with 85% of the generation coming from natural gas–fired generation has a higher combined cost of about $56/MWh. The natural gas–fired generation produces 1,003 pounds of CO_2 per MWh while the wind and natural gas–fired integrated alternative is 15% lower. Therefore, if the purpose of a wind generation share mandate is to lower CO_2 emissions from the market outcome, then the difference in cost divided by the difference in CO_2 emissions yields an implicit cost of CO_2 abatement of about $59 per metric ton.

The cost of offsetting the CO_2 impact of PJM nuclear closure and replacement involves the option of purchasing CO_2 emission allowances. Within 2013–16, the market-clearing price of CO_2 emission allowances in the Regional Greenhouse Gas Initiative (RGGI), which sets a price for CO_2 emissions in some PJM states, ranged from $3.5 to $8.5 per metric ton. These prices are below the midrange estimates of the social cost of carbon if about $43 per metric ton.[26]

PJM CO_2 emission abatement through emission allowance payments provides more than five times the CO_2 emission abatement per dollar compared with mandates of renewable resources. Since continued nuclear operation is an even less costly CO_2 emission abatement compared with RGGI allowance purchases, the environmental bang for the buck is even greater from continued nuclear operation. Employing the midpoint estimate ($43 per metric ton) as an estimate of an appropriate CO_2 emission cost indicates that PJM nuclear generation provides an annual $2 billion worth of PJM CO_2 emission abatement.

The bottom line is that uneconomic PJM nuclear retirements and replacements caused by market distortions are a lose/lose proposition because the outcome involves both higher power production costs as well as higher CO_2 emissions. Since environmental responsibility requires making efficient environmental cost and benefit trade-offs, uneconomic PJM nuclear closures and replacements are not environmentally responsible.

Conclusions

The primary finding of this analysis is that the 65 million consumers who rely on PJM grid-based power supply are better off if something is done to prevent the uneconomic closures of PJM nuclear resources because the PJM power supply portfolio is more efficient, more resilient, and environmentally responsible with the continued contribution of cost-effective nuclear resources.

The impact of uneconomic PJM nuclear closures and replacement on consumer electricity bills is significant, ranging from 9% to 18% depending on the price of natural gas for the replacement generation. This conclusion is at odds with the assertion that consumers are insensitive to electricity costs. Therefore, the approach employed in this study to translate consumer behaviors and choices into preferences for resilient availability and resilient cost levels for affordable and environmentally responsible grid-based electricity provided a framework grounded in consumer behavior data. The approach defined metrics to evaluate the impact of uneconomic nuclear power plant closures and replacements in the PJM power system. Further, the fully documented statistical analyses of consumer demand used to quantify the consumer net benefits

26. Michael Greenstone, Elizabeth Kopits, and Ann Wolverton, "Developing a Social Cost of Carbon for US Regulatory Analysis: A Methodology and Interpretation," *Review of Environmental Economics and Policy* 7, no. 1 (1 January 2013), https://doi.org/10.1093/reep/res015, retrieved 27 March 2018.

from electricity consumption provides a transparent metric to quantify the impact of losing cost-effective power supply.

Resilience in power supply is a controversial issue, and the results of this study may be different from other studies. The conclusion is that transparency in approach and the reliance on a minimum of assumptions will assist in comparing this study to others. Therefore, this analysis specifies assumptions and quantifies efficiency and resilience impacts with a backcasting approach across 2013–16 to incorporate a realistic set of PJM operating conditions and disruptive events. Comparing actual PJM outcomes with the outcomes from the backcasting analysis of the closure and replacement of PJM nuclear resources scenario provided a transparent analysis that can be replicated in a straightforward way because the analysis minimizes the influence of assumptions by holding all other analytical conditions equal to the actual recent historical conditions.

Quantifying the value of cost-effective nuclear generating resources in the efficient diversity of a PJM power supply portfolio does not infer a preference for one fuel or technology over another. Instead, the assessment focuses on efficient diversity in a power supply portfolio and confirms that consumers benefit from a cost-effective mix of fuels and technologies in their grid-based power supply.

The quantifiable benefits of continued PJM nuclear resource operations despite insufficient market cash flows leads to the conclusion that current market viability does not provide a test of economic cost effectiveness. Instead, the analysis indicates PJM market outcomes involve distortions.

The linkage between market distortions and current discord between public policies and market operations is a fuel and technology neutral assessment. Pointing out that mandates and subsidies of renewable resources distort market operations does not mean that intermittent wind and solar resources are not part of the cost-effective mix of fuels and technologies. Instead, the analysis indicates that the market distortions arise from command and control policy approaches to support renewable development rather than encouraging efficient market-based renewable development by putting an appropriate price on CO_2 emissions for all rival generators in the marketplace.

Noting that counting all costs, including CO_2 emissions costs, is a requirement for an efficient market outcome does not mean that addressing the resilience challenge in the US power system requires eliminating all subsidies and mandates and imposing a uniform CO_2 emission charge. Assuming that eliminating the cause of a problem is the only available solution does not recognize the political infeasibility of rapidly undoing entrenched public policies. Instead, the analysis supports consideration of other options to offset the predictable consequences of current market distortions.

The conclusion that market interventions can offset the impacts of market distortions is consistent with actions being taken in some states. Current feasible policy options to augment cash flows for cost-effective generating resources and to produce outcomes closer to an efficient market end state involve providing compensation for attributes—such as cost-effective contributions to capacity resilience, contributions to production cost resilience, contributions of flexible operating capabilities, or contributions to lower power system CO_2 emission levels. For example, California has implemented ramping products to compensate for flexible generation attributes, while Illinois, New York, and Connecticut have implemented zero-emission credits. However, an apparent challenge to implementing offsetting market interventions is emerging from market stakeholder conflicts. Since wholesale electricity market distortions affect rival producers in different ways, competition spills over from the marketplace to the policy arena where rival electricity producers reveal the preference to support interventions that offset the negative impacts of market distortions to their own fuel source or technology while opposing interventions that offset negative impacts on their competitors.

Suppressing capacity and energy prices below the price levels expected in an undistorted and efficient marketplace is not a sustainable long-run outcome. Consequently, generating plant retirement and investment decisions will respond to distorted wholesale energy and capacity price signals. As market distortions cause uneconomic power plant retirements, market forces will move capacity and energy prices levels to reflect the marginal costs of the less efficient fuel and technology mix in the supply portfolio. Preventing uneconomic nuclear closures and replacements will result in lower long-run electricity costs. These actions to offset the impacts of current market distortions do not increase distortions because nuclear resources are cost-effective resources in an undistorted market outcome.

PJM faces the challenge to take actions to address the predictable consequences arising from the unresolved lack of harmony between public policies and market operations. Such actions are imperative to meet the consumer preferences for affordable, reliable, resilient, and environmentally responsible electricity services. Since PJM is the largest electricity market on earth and widely regarded as a model for electricity policy formulation and market design, actions to offset the consequences of market distortions have the potential to not only benefit electric consumers in PJM but also produce a highly influential example for other power systems to follow in addressing similar challenges.

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