# The Value to New Jersey Consumers of Salem and Hope Creek Nuclear Power Generation in Providing Reliable, Resilient, Affordable, and Environmentally Responsible Electricity

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## About the report

The Value to New Jersey Consumers of Salem and Hope Creek Nuclear Power Generation in Providing Reliable, Resilient, Affordable, and Environmentally Responsible Electricity 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 New Jersey consumers and the New Jersey economy of the premature retirement of the Salem and Hope Creek nuclear power plants. This research was supported by Nuclear Matters.

This report was prepared for Nuclear Matters. IHS Markit is exclusively responsible for all of the analysis and content.

# Contents

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## Executive summary

Operation of the Salem and Hope Creek nuclear power plants in New Jersey produces benefits for New Jersey consumers. The plants make power supply more resilient to major system failures, such as natural and manmade disasters, and limit the environmental impact of electric production, particularly the electricity carbon footprint. In addition, the continued operation of Salem and Hope Creek produces lower and more stable power supply costs compared with the outcome if the plants closed prematurely.

Consumers in New Jersey are at risk of permanently losing the benefits of the state's nuclear generation owing to the lack of harmonization between public policies and PJM market operations and rules. In particular, market failures to fully compensate New Jersey nuclear generators for contributions that ensure power system security of supply and lower emissions, coupled with market distortions like mandates of subsidized renewable generation, result in lower electric generator cash flows compared with the levels expected from an undistorted, efficient market outcome. The cumulative impacts to New Jersey of the premature closures and replacements of the Salem and Hope Creek nuclear plants are summarized in Table 1.

Since PJM operates a capacity market alongside its energy market, PJM market failures and distortions that suppress wholesale electric energy prices and the associated energy market cash flows cause underinvestment in electric production efficiency rather than in installed capacity. The bottom line is that an undistorted PJM market outcome would efficiently pace the size and mix of cost-effective power supply investment by generating prices for capacity and energy that internalize all costs, including the cost of carbon dioxide ($CO_2$) and other pollutant emissions. Such an undistorted, efficient market outcome would lead to a diverse technology and fuel electric supply portfolio of cost-effective peaking, cycling, base-load, and intermittent resources. As a result, the power supply portfolio would not lose base-load nuclear power plants that are lower cost to continue to operate than the costs associated with the new supply being added to the marketplace.

Table 1

**Cumulative impacts to New Jersey consumers from the premature retirements of the Salem and Hope Creek nuclear plants**

| Description | Cost |
|---|---|
| **Less resilient power supply** | • **\$70–230 million** per disruptive event of similar severity and duration as the 7 January 2014 polar vortex |
| | • **\$440–790 million** per 24-hour disruption of similar severity as the 7 January 2014 polar vortex |
| **Less statewide economic activity** | • **\$820 million** annual decline in real gross state product |
| | • **6,100** fewer jobs per year |
| **More variable consumer power bills** | • **\$8.6–12.6 million** annual cost to New Jersey to stabilize PJM production cost variability |
| **Increased $CO_2$, $SO_2$, and $NO_x$ emissions** | • **\$530 million** annual increase in CO2 emission costs |
| | • **\$420,000** annual increase in SO2 and NOX emission costs |
| **Higher consumer power bills** | • **\$404 million** annual increase in annual power payments |

Source: IHS Markit © 2017 IHS Markit

Nationally, awareness is growing regarding the rising challenge of maintaining grid resiliency as more base-load nuclear and coal power plants are retired prematurely. In September 2017, Secretary of Energy Rick Perry issued a letter to the Federal Energy Regulatory Commission recommending new rules to offset market distortions caused by a lack of harmonization between public policies and electricity market operations, noting that

> Distorted price signals in the Commission-approved organized markets have resulted in under-valuation of grid reliability and resiliency benefits provided by traditional baseload resources, such as coal and nuclear. ... The proposed rule requires the Commission-approved organized markets to develop and implement market rules that accurately price generation resources necessary to maintain the reliability and resiliency of our Nation's electric grid.[1]

Although the specifics of the approach are not yet available, the initiative shows that the discord between public policies and market operations is currently high on the electricity policy agenda.

New Jersey is at a critical juncture. To do nothing to address current PJM market failures and distortions will lead to underinvestment in electric production efficiency, moving the electric supply portfolio toward a less efficient generation mix with too few nuclear base-load resources. As a result, not addressing the existing disharmony between public policies and market operations increases the probability of uneconomic closure decisions and the replacement of the Salem and Hope Creek nuclear power plants. These closures would predictably result in

- **Less resilient power supply.** The number of possible low-probability but high-impact events and their statistical independence means that some kind of significant disruptive event is likely to confront the PJM power system within the coming decade, such as another polar vortex episode, a Sandy-type hurricane landfall, a natural gas pipeline or storage facility failure, a foreign or domestic terrorist attack, or legislative or court interventions constraining the natural gas supply chain. Therefore, prudent planning ought to incorporate resilience to the range of possible significant deviations from expected normal operating conditions. A retrospective analysis of the 2014 polar vortex conditions in PJM illustrates the resilience benefits provided by the New Jersey nuclear power plants at the time. Our analysis finds that **the cost to New Jersey consumers, had the New Jersey nuclear plants retired prior to the** 7 **January 2014 polar vortex, would have been between $70 million and $230 million.** Because New Jersey's nuclear plants provide resilience benefits to all PJM consumers, the total cost of the loss of the New Jersey nuclear plants is around 10 times higher. Since 2014, the PJM power supply has become more reliant on natural gas pipelines and operations and is therefore less resilient to similar events. The upper end of this range reflects how recent changes in the PJM power supply portfolio have increased the resilience benefits provided by the New Jersey nuclear plants. Going forward, other high-impact events may cause a loss of load for an even longer duration. The benefit to New Jersey of preventing a similar loss of load lasting 24 hours averages $440–790 million.

  The polar vortex of January 2014 is just one example of the type of events that can stress the power supply. Events in the future may occur with more or less frequency and with more or less disruptive force. Therefore, the analysis of the polar vortex alone cannot be used to define resiliency planning. However, this analysis demonstrates that the New Jersey nuclear plants are important to the resilience of the PJM power supply and that their importance has increased following the power supply portfolio's recent increase in dependency on the natural gas supply chain.

- **Negative statewide impacts on economic activity.** The retail power price increase in New Jersey associated with the closures of Salem and Hope Creek causes **real gross state product to decline 0.14%, equal to $820 million in 2017 prices.** The increase in retail power prices hurts the New Jersey labor market, **contributing to total job losses of 6,100 per year.**

- **More varied monthly New Jersey consumer power bills.** The electric variable cost of production accounts for about 15% of consumer power bills. Backcasting indicates that the variation (standard deviation) of PJM variable production costs would increase by 11% if the base-load nuclear power plants with stable generation fuel costs of about 0.7 cents per kWh were closed and replaced primarily by natural gas–fired generating plants whose monthly fuel costs per kilowatt-hour varied in the past four years from a low of 1.1 cents in March 2016 to a high of 10.4 cents in January 2014. The annual cost to replace the portfolio diversity effect of the Salem and Hope Creek nuclear resources on variable production cost variation with financial hedges of natural gas prices amounts to $77–112 million per year in PJM. **The**

1. Secretary of Energy Rick Perry, Letter to the Federal Energy Regulatory Commission Chairman and Commissioners, 28 September 2017, Subject: Secretary of Energy's Direction that the Federal Energy Regulatory Commission Issue Grid Resiliency Rules Pursuant to the Secretary's Authority Under Section 403 of the Department of Energy Organization Act.

**New Jersey consumers' share of this cost is \$8.6–12.6 million per year,** indicating the implicit value of the more stable and predictable power bills produced by having nuclear generation in the supply portfolio rather than a higher exposure to natural gas–fired generator cost variability.

- **Greater environmental impacts from electric production.** New Jersey nuclear generation accounts for 95% of the state's zero-emission, non–$CO_2$-emitting electric generating resources. Replacing the 28,750 GWh/y of electric output from the Salem and Hope Creek nuclear power plants with a 15%/85% mix of renewable and natural gas–fired generation increases annual electricity sector $CO_2$ emissions by 13 million metric tons (MMt). To put this into perspective, New Jersey electric generation emitted 16.1 MMt and 19.4 MMt of $CO_2$, respectively, in 2012 and 2015. Using a midrange estimate of \$42 per metric ton for the social cost of carbon puts the environmental impact value of the $CO_2$ emission abatement provided by the continued operation rather than replacement of the Salem and Hope Creek nuclear power plants at **\$530 million per year.** In addition, the replacement of Salem and Hope Creek with the same mix of renewable and natural gas–fired generation will increase annual electricity sector nitrogen oxide ($NO_x$) and sulfur dioxide ($SO_2$) emissions by 3,063 metric tons and 118 metric tons per year, respectively. Using the 2016 Cross-State Air Pollution Rule market allowance prices in New Jersey for $NO_x$ and $SO_2$ emissions puts the additional environmental impact of emissions at **\$420,000 per year.**

Table 2

**Annual increase in bills by customer class in New Jersey due to retirement of Salem and Hope Creek nuclear plants**

| Customer class | 2016 retail price of electricity (\$/kWh) | Increase in electricity prices due to the retirement of Salem and Hope Creek nuclear plants | Increase in total electricity costs due to the retirement of Salem and Hope Creek nuclear plants (million dollars) |
|---|---|---|---|
| Residential | 15.75 | 3.4% | 158 |
| Commercial | 12.42 | 4.3% | 207 |
| Industrial | 10.14 | 5.3% | 39 |

Source: IHS Markit, Energy Information Administration © 2017 IHS Markit

- **Higher New Jersey consumer power bills.** Without Salem and Hope Creek generation, the annual average cost of electric production in PJM would increase by about \$1.6/MWh under PJM market conditions similar to 2013–16. New Jersey nuclear closures would also eliminate a \$3.8/MWh locational marginal price (LMP) benefit for electric energy in New Jersey compared with the rest of PJM operating under 2016 PJM market conditions with delivered natural gas prices to generators reflecting the \$3.29/MMBtu average price level for 2013–16. Altogether, the higher PJM average cost of electric production and the loss of the LMP differential would increase the cost of New Jersey wholesale electricity by \$5.4/MWh. **This annual cost increase adds \$404 million in New Jersey consumer power payments that would involve a 4% increase in the average retail power price.** The percent increases to specific customer classes from 2016 retail price levels are summarized in Table 2.

## Overview

In 2016, New Jersey electricity consumers spent $10.1 billion to purchase 74,769 million kWh at an average retail price of 13.5 cents per kWh. Analyses of household and business purchasing decisions reveal that consumers valued grid-based electricity purchases significantly more than the amount that they paid for them. The high value-to-cost ratio is not surprising for a commodity that is considered a necessity in a modern, developed economy in the digital age. Consequently, the high ratio of electric service value to cost unsurprisingly drives consumers to demand a high degree of reliability and resilience in grid-based power supply. In addition, consumers reveal a preference for stable and predictable power bills as well as a desire to address the environmental challenge of global warming.

The continued operation of the Salem and Hope Creek nuclear generating resources in New Jersey aligns with consumer preferences. The electric capacity and energy from the Salem and Hope Creek nuclear power plants made overall PJM power supply more resilient and New Jersey consumer power bills lower and less variable from month to month compared with the expected alternative outcome from premature closure and replacement. In addition, replacing the Salem and Hope Creek nuclear power plant output with the 15%/85% mix of renewable and natural gas–fired generation constituting the current PJM new power supply pipeline would increase annual carbon dioxide ($CO_2$), nitrogen oxide ($NO_X$), and sulfur dioxide ($SO_2$) emissions.

Consumer preferences for affordable electricity prices extend beyond their power bills, because the price of electricity affects the level of economic activity in the New Jersey economy. The New Jersey electricity price relative to other states and nations affects the competitive position of New Jersey business in the national and global economy. Consequently, increases in New Jersey's relative electricity price result in declines in the level of per capita gross state product (GSP), in-state jobs, and consumer disposable income.

The consumer benefits from the operation of the Salem and Hope Creek nuclear power plants are at risk because of a lack of harmony between public policies and wholesale electricity market operations. The 4 million New Jersey electricity consumers are among the more than 27 million consumers that rely on the PJM electricity system for grid-based electricity supply. But here is the rub: mandates of subsidized intermittent renewable generation are suppressing wholesale power prices, and current PJM wholesale price formation rules do not fully incorporate the cost of the necessary adjustments to ensure security of power system operations. The combined impact is that wholesale market cash flows fail to fully compensate generators for the efficiency and resilience attributes provided by existing resources.

The five predictable consequences for New Jersey electricity consumers if PJM market distortions cause the premature closure of the Salem and Hope Creek nuclear power plants are

- **Less resilient market supply.** Premature base-load power plant retirements and replacement with natural gas–fired generating resources increase the natural gas generation share beyond the share expected in an efficient market outcome. This larger share of natural gas–fired generating resources therefore increases the power supply portfolio's exposure to the availability risks of the natural gas fuel supply chain. The greater risk exposure translates into higher probabilities for power outages when natural gas deliverability conditions deviate from normal, as happened during the polar vortex in 2014, when the contributions of New Jersey nuclear resources averted a $73–230 million outage cost for New Jersey consumers.

- **Negative statewide economic impacts.** Higher retail power prices relative to other states and nations lower the competitive position of New Jersey businesses and reduce jobs and the value of the GSP. The continued operation of Salem and Hope Creek prevents power price increases that cut in-state jobs by about 6,100 and reduce New Jersey GSP by more than $800 million per year.

- **More varied monthly power bills.** Premature base-load power plant closures result in a greater reliance on natural gas–fired resources. When the marginal cost of natural gas–fired resources sets wholesale power prices an increasing percentage of the time, New Jersey consumers face added exposure in their monthly power bills to the impacts from natural gas price spikes, seasonal price movements, and multiyear natural gas price cycles. The cost to replace the stability that Salem and Hope Creek provide to monthly New Jersey power bills is about $8.6–12.6 million per year.

- **Greater environmental impacts.** Mandates of intermittent renewable technologies cause premature nuclear power plant retirements and a greater reliance on natural gas–fired generation that results in a net increase in $CO_2$, $SO_2$, and $NO_x$ emissions from power generation of 13 million metric tons (MMt), 3,063 metric tons, and 118 metric tons, respectively, with an environmental impact cost of more than $530 million per year.

- **Higher power bills.** The cost of electric supply increases when electric service is less reliable and when the suppression of nonpeaking power plant cash flows causes nuclear power plants to retire even though the cost of continued operation is lower than the cost of the replacement power supply coming from mandated renewable and new natural gas–fired generating technologies. Suppression of wholesale power prices in the short run leads to higher wholesale power prices in the long run as the power supply portfolio mix becomes less efficient with too many peaking power plants and too few base-load power plants. The premature closure and replacement of the Salem and Hope Creek nuclear power plants would increase New Jersey retail electricity prices by 4% and add $404 million to New Jersey consumers' power bills.

New Jersey is at a critical juncture. To do nothing to harmonize state policies and PJM market operations allows market distortions to erode nonpeaking power supply resource cash flows. These conditions increase the probability that the Salem and Hope Creek nuclear power plants will close prematurely and that New Jersey consumers will face higher and more varied monthly power bills, less power system resilience, greater environmental impacts, and strains on the state economy.

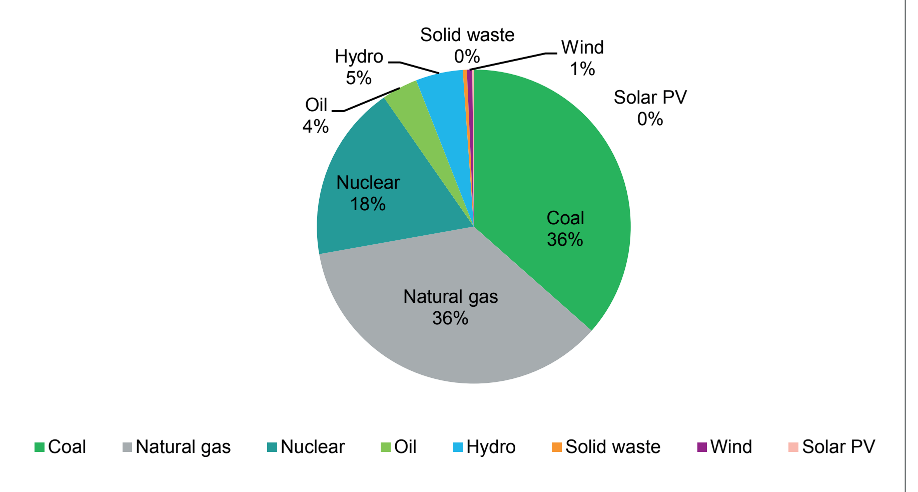
## New Jersey's link to PJM

New Jersey is one of the 13 states (Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, and West Virginia) and the District of Columbia that rely, in whole or part, on the PJM Interconnection for grid-based electricity supply.

New Jersey electricity consumers account for 4 million of the more than 27 million consumers that rely on the PJM electricity system to produce reliable, resilient, affordable, and environmentally responsible grid-based electricity supply. The 74,769 million kWh that New Jersey electricity consumers purchased in 2016 accounted for 11% of aggregate consumer load supplied by the PJM generating portfolio. On the supply side, New Jersey power plants provided more than 19 GW of generating capacity to the PJM portfolio shown in Figure 1. These New Jersey electric generating resources currently account for 11% of the net dependable capacity deployed to reliably meet PJM demand at all times throughout the year.

Figure 1

**PJM installed generation capacity, December 2016: 182.4 GW**




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

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Current utilization of the New Jersey generating capacity provides more than 8% of annual PJM electric generation, and the New Jersey nuclear power plants currently account for 95% of New Jersey non–$CO_2$-emitting generation.[2]

PJM manages the grid that physically connects consumer demands to producer supplies, and it employs markets for electric energy, capacity, and ancillary services to coordinate the interaction of aggregate demand and supply with market price signals. PJM employs a bid-based competitive

2. Source: US Energy Information Administration (EIA), Frequently Asked Questions, https://www.eia.gov/tools/faqs/faq.php?id=74&t=11, accessed 21 September 2017.

process to centrally dispatch generation resources to meet the aggregate consumer load. Competitive forces drive rival power generators to bid electric supply based on their short-run marginal costs (SRMC). These SRMC reflect the incremental variable costs of fuel and variable operation and maintenance costs expressed as a cost per unit of output. As a result, the electric supply curve in the PJM market reflects the SRMC of rival generators ordered from lowest to highest.

PJM balances demand and supply in real time but does not determine a single price to clear the energy market. As the grid operator, PJM must coordinate the power system security-constrained movement of wholesale electricity between producers and consumers. Since PJM operating conditions involve dynamic transmission constraints, PJM system operators must alter generation dispatch to manage transmission flows, voltage, frequency, and system security. This security-constrained dispatch of available supply to demand in real time prevents market forces from completely closing the SRMC differences across all PJM generators throughout the year. Therefore, PJM determines the locational marginal price (LMP) at more than 9,000 load and 2,000 generation pricing points in day-ahead and real-time electric energy markets and determines locational prices for capacity in 27 locational deliverability areas.

The PJM energy market produces an efficient dispatch because market forces push to minimize the SRMC differentials among generating resources at any point in time. As conditions change, market operations shift electric production toward producers with lower SRMC–based supply bids and away from producers with higher SRMC–based supply bids whenever the transmission and security of supply constraints allow these cost-effective generation shifts to occur within the grid. As a result, the PJM LMPs are highly correlated through time. For example, the correlation between the hourly New Jersey LMPs and the rest of PJM's average LMPs across 2014 to 2016 was 0.936, indicating that as relative fuel prices changed, market forces created constant pressure to minimize SRMC differentials and, thus, maximize efficient dispatch.

Owing to security of supply and transmission constraints, market forces cannot eliminate LMP price differentials in PJM. PJM transmission and security of supply constraints prevent some electric generation with lower marginal costs from flowing out of constrained transmission zones to displace higher–marginal cost generation elsewhere in PJM. However, these LMP differentials do not necessarily indicate an inefficient PJM market outcome. PJM LMPs reflect the differences in locational SRMC of generation resources, and, thus, the PJM LMP differentials indicate the benefit of relieving security of supply and transmission constraints. Since the benefits of relieving a transmission constraint can be less than the cost to do so, some transmission constraints within PJM are not cost-effective to relieve. As a result, economic transmission constraints can cause persistent LMP differentials in an efficient security-constrained PJM market outcome.

PJM power plant retirement and replacement trends indicate that in the past decade, PJM has lost proportionately more low-SRMC supply than New Jersey. In particular, the nuclear share of the New Jersey–based electricity supply curve is much larger than the nuclear generation share in the rest of PJM's supply curve. Nuclear generation is a base-load technology incorporating significant up-front investment in the efficiency of transforming primary energy into electricity. As a result, the nuclear generation SRMC is typically lower than a natural gas–fired combined-cycle (CC) generating technology that is increasingly characterizing the marginal generating resource in the rest of PJM. The PJM State of the Market Report indicates that the average SRMC of PJM nuclear power plants was 44% lower than the SRMC of a natural gas–fired CC technology in 2016.[3]

The existing transmission constraints between New Jersey and the rest of PJM currently prevent some of the lower–marginal cost nuclear electric generation from flowing out of New Jersey to displace higher–marginal cost generation elsewhere in PJM. Hourly 2016 LMPs indicate that the generating resources with incremental costs lower than those of a natural gas–fired CC generating resource were setting the LMP price 18% of the time within New Jersey compared with only 11% of the time within the rest of PJM.

The 2016 market data indicate that current transmission constraints distribute a disproportionate share of the benefit from the relatively lower–marginal cost New Jersey nuclear generation to New Jersey consumers by lowering the percentage of time when the higher SRMC of natural gas–fired generators is setting the energy price at the New Jersey LMPs compared with the rest of PJM. As a result, in 2016 the load-serving entities (LSEs) within New Jersey purchased electric energy for consumers at the PSEG, Atlantic City Electric, and Jersey Central pricing points with an average LMP

3. Monitoring Analytics, LLC, *2016 State of the Market Report for PJM*, p. 283.

that was $3/MWh less than the average LMP for the rest of PJM. The disproportionate benefit to New Jersey consumers accruing from the New Jersey nuclear generation and the transmission constraints provided a $224 million savings to New Jersey consumers in 2016.

Transmission constraints limit but do not eliminate the flow of benefits from the Salem and Hope Creek nuclear generating resources to the rest of PJM. Therefore, New Jersey consumers do not capture all of the benefits of the New Jersey nuclear power plants; instead, they share the benefits, with the New Jersey nuclear generation lowering the average generating cost in the rest of PJM. Backcasting PJM total electric production costs for 2013–16 with all conditions held constant, except with the New Jersey nuclear power plants closed and replaced by a 15%/85% mix of renewable and natural gas–fired CC generation, indicates that the overall PJM electric production costs would have been about $1.2 billion higher. The Salem and Hope Creek nuclear power plants accounted for 85% of this overall PJM electric production cost impact.

Analysis of 2016 PJM market data illustrates that the benefit of nuclear power generation to New Jersey consumers as well as the rest of PJM is sensitive to the SRMC cost difference between nuclear generation resources and natural gas–fired CC power plants. This relationship is important, because the delivered price of natural gas varies considerably through time. In just the past three years, the annual average delivered price of natural gas was as low as $2.13/MMBtu in 2016 and as high as $4.60/MMBtu in 2014. As a result, if the delivered price of natural gas had been $4.60/MMBtu in 2016 rather than $2.13/MMBtu with all other conditions held constant, then the incremental fuel generation cost differential would have expanded from $8/MWh to $26/MWh between New Jersey nuclear generation and natural gas CC generating plants operating in the rest of PJM (based on an average natural gas–fired generator heat rate of 7,100 Btu/kWh). If the natural gas price had been $4.60/MMBtu rather than $2.13/MMBtu in 2016, then the difference in incremental fuel costs across the 7% of the time when the natural gas–fired CC SRMC is setting prices in the rest of PJM and not at the New Jersey LMPs would have increased the annual LMP differential between New Jersey and the rest of PJM from $3/MWh to $4.8/MWh. The implication is that with PJM market conditions similar to those in 2016, each $1/MMBtu increase in natural gas prices would result in an average New Jersey LMP being $0.7/MWh lower compared with the rest of PJM.

The average delivered price of natural gas to New Jersey electric generators over 2013–16 was $3.29/MMBtu, and this four-year average price level is closer to the level expected in the future than the cyclically low delivered price of $2.13/MMBtu in 2016. Therefore, the estimate of the ongoing value to New Jersey consumers of the LMP differential created by current transmission constraints and the SRMC differences between New Jersey nuclear resources and natural gas–fired resources in the rest of PJM is about $3.8/MWh.

## Premature closure of Salem and Hope Creek results in less resilient power supply

Engineering and economic principals consistently indicate that an efficient electric supply portfolio comprises a diverse set of technologies and fuels. This diversity of a cost-effective electric supply portfolio inherently provides resilience to a wide range of risk factors associated with each type of generating resource. The resilience of a diverse power supply portfolio arises from the independence among the risk factors across generating technologies and fuels. For example, the polar vortex in 2014 prevented fuel deliveries to natural gas–fired generators in PJM, but it did not affect the availability of fuel to nuclear power plants. Because of this lack of correlation among power supply risk factors, not having all of your eggs in one basket in a power supply portfolio generates valuable power supply resilience to myriad power supply risk factors across all fuels and technologies.

Resilience created from diversity is an inherent attribute of a cost-effective electric supply portfolio, because there is no “one-size-fits-all” electric generation technology or fuel source that can reliably meet the recurring annual real-time pattern of power system aggregate consumer demand at the lowest cost.[4]

Although a simple levelized cost of energy (LCOE) metric can indicate that a single generating technology provides the lowest LCOE on a stand-alone basis under a given set of conditions, a cost-effective supply portfolio would not be made up of this technology alone. Such a single-source supply portfolio ignores the time dimension of power supply and

4. Appendix A summarizes the current available state of technology for a variety of power generation technologies that bring different performance characteristics to an electric supply portfolio.

potential deviations from normal operating conditions. For example, advances in solar PV technologies continue to lower the stand-alone cost of generating electricity when the sun shines. However, a recent study by the US Department of Energy's (DOE) National Renewable Energy Laboratory finds that about 65% of a typical rooftop solar energy customer's electricity demand is noncoincidental with the electricity generated from the rooftop solar PV units.[5] Therefore, if solar PV provided the lowest LCOE compared with other electric supply technologies, a 100% solar PV power supply portfolio would neither be capable of meeting peak demands nor be capable of supplying consumers connected to the grid with the electricity that they want, whenever they want it.

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

The implication is clear—a power supply portfolio comprising the technology with the lowest time-ignorant, stand-alone LCOE would not deliver either reliable electricity to consumers or electric supply that is resilient to the changes expected in the power system operating environment.

The resources available to instantaneously match electric supply and demand involve operable generating capacity as well as grid-level electric storage technologies and demand-side resources. Since the availability of any of these resources is uncertain at any point in time, providing reliable electric service requires operating with some of these resources in reserve. Therefore, a robust reserve uses diversity of capacity to mitigate potential deviations from normal operating conditions affecting the availability of a given generating technology or fuel source. For example, an operating reserve made up entirely of natural gas–fired resources supplied from a common pipeline could provide power supply reliability under normal pipeline operating conditions. However, the reserve would not be resilient to a pipeline disruption. By contrast, a diverse operating reserve comprising dual-fueled capacity (pipeline natural gas and on-site liquid fuel inventory) would be capable of reliable generation while also being resilient to a potential significant deviation from normal natural gas pipeline operating conditions.

A well-structured electricity market will produce an efficient market outcome by generating both the level and variability of capacity and the energy prices necessary to provide investment signals to produce a cost-effective electric supply portfolio. By contrast, the lack of harmonization between public policy and market operations that causes a distorted marketplace that suppresses energy market price signals compared with the efficient market outcome will produce less efficient diversity of power supply. In particular, market distortions that reduce the cash flows from the energy market will lead to underinvestment in electric production efficiency and produce an electric supply portfolio with too many peaking resources and too few base-load resources.

PJM market distortions reduce the cash flows from the energy market and increase the probability of premature base-load power plant retirements. When this happens, the cost and performance profiles of alternative generating technologies indicate that natural gas–fired generating technologies will be the primary source of replacement generation. This trend moves the PJM supply portfolio toward a greater reliance on natural gas–fired generating technologies than expected in an efficient market outcome. As the portfolio mix becomes increasingly dominated by natural gas–fired generation technologies, the power supply portfolio becomes more exposed to the risks of the natural gas supply chain than would be the case with an efficient market outcome. As this unfolds, the concern becomes having an electric supply portfolio with too many eggs in one basket.

The expected operating lives of natural gas–fired electric generating plants typically range from two to four decades. Figure 2 shows the multiyear natural gas price cycles that characterized natural gas market outcomes over the past three decades. The long-run drivers of natural gas price cycles are technology changes, demand uncertainty, public policy shifts, market participant recognition lags, and market demand and supply adjustment lags.

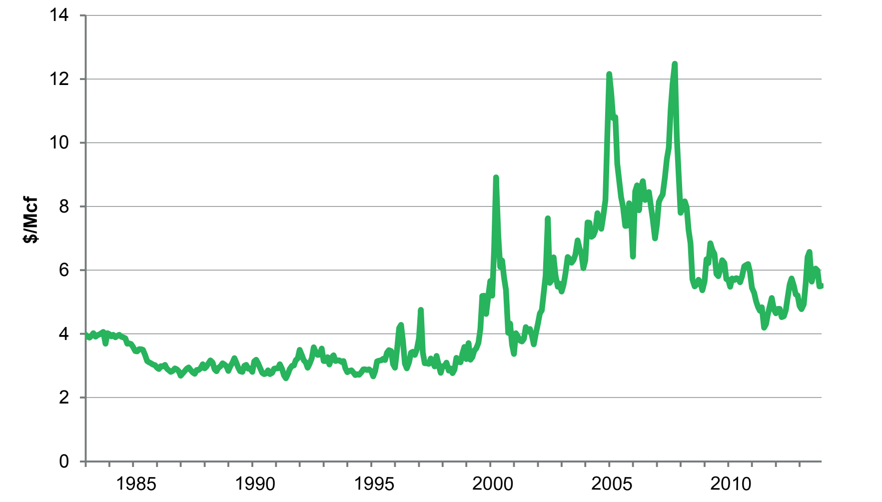
5. Lori Bird, Carolyn Davidson, Joyce McLaren, and John Miller, *Impact of Rate Design Alternatives on Residential Solar Customer Bills: Increased Fixed Charges, Minimum Bills and Demand-Based Rates,* National Renewable Energy Laboratory, US DOE, September 2015, https://www.nrel.gov/docs/fy15osti/64850.pdf, retrieved 13 October 2017.

In addition to persistent long-run price cycles, 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, weeks, or months when natural gas prices spike at multiples of the normal price level, as shown in the monthly data displayed in Figure 3. The lesson from natural gas markets is that the most influential factor driving significant short-term excursions of expected natural gas price levels is the deviation in weather from normal conditions.

Ideally, short-run natural gas price spikes function to allocate a limited amount of natural gas to the most highly valued applications. However, sometimes prices alone cannot bring short-run demand and supply into balance. Sometimes when the conditions cause natural gas prices to spike, deliverability constraints are severe enough that some generators are unable to secure natural gas supply at any price. Such conditions arose in PJM during the polar vortex in 2014, when some natural gas–fired generators in PJM were unable to obtain all of the natural gas they wanted even though they had firm natural gas supply contracts in place. As the US DOE recently noted, "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, impact grid reliability."[6]

Figure 2

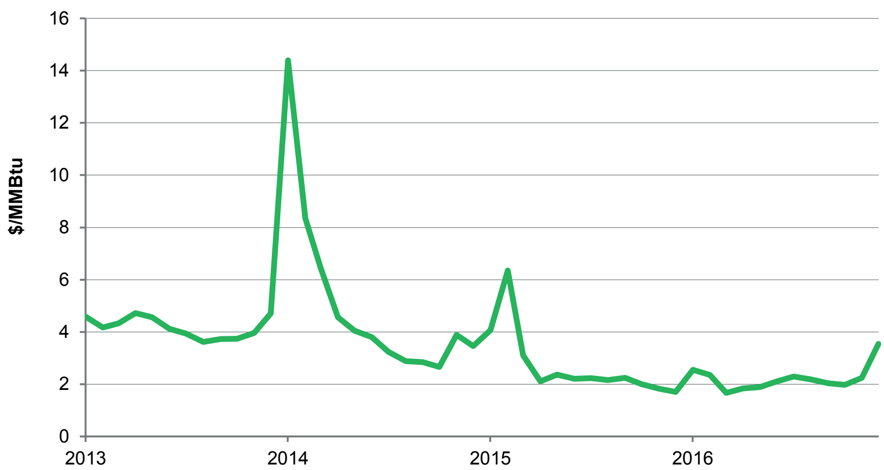
**US average national natural gas price citygate, 1986–2016**




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

Figure 3

**Average monthly delivered price of natural gas to PJM power sector, 2013–16**




Source: IHS Markit, EIA © 2017 IHS Markit

New Jersey electricity consumers face potential significant costs when severe weather, grid overloading, power station failures, and other significant deviations from normal operating conditions exceed the resilience level of the power system to avoid electric service interruptions. When Hurricane Sandy hit New Jersey in October 2012 and interrupted electric service across several days, the cost associated with electric service interruptions became apparent to a large

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

number of New Jersey consumers. In response, the high value that consumers place on resilient power supply triggered a surge in installations of backup generation technologies in the following year.[7]

New Jersey consumers' decisions to install backup generation systems reveal just how highly they value critical grid-based electric supply. 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 annual grid-based supply disruptions is roughly 100 times the average price of 13.5 cents per kWh that New Jersey households pay for grid-based power supply. Many commercial and industrial customers—especially customers with critical electric applications in hospitals and data centers—install backup generation, and these actions reveal high valuations on resilient electricity supply similar to the residential consumers.

Electricity markets incorporate the estimates of the value consumers place on lost electric services. For example, in 2014 the Electric Reliability Council of Texas (ERCOT) began employing an estimate of the value consumers place on electric service reliability in its implementation of the operating reserve demand curve real-time electric wholesale market intervention to compensate for the reserves employed to reduce the probability of electric system outages. ERCOT employed an estimate of the value of lost load of $9,000/MWh, a value that was about 100 times the 2015 average retail power price of 8.7 cents per kWh.

Estimates of the high values consumers place on electricity services align with estimates of annual power outage costs in the United States. The track record indicates that past electric service interruption costs exceeded hundreds of billions of dollars per year.[8] Of course the timing and duration of outages affect consumer impacts, but simply taking estimates of the annual costs and dividing by the annual average outage duration indicates that increasing the frequency of the typical electric service disruptions in the United States involves about $75 billion per hour of electric service interruption costs.[9]

The cost of an electric outage in the PJM territory is about 17% of the total US outage costs and roughly $12.6 billion per hour, or $170/kWh (in 2016 dollars). This is simply an allocation of estimates of national outage costs to PJM based on electric consumers in PJM accounting for about 17% of US power supply and the economic activity powered by PJM grid-based electric supply accounting for about 20% of the US total GDP. Similarly, New Jersey's share of outage costs would indicate about a $1.4 billion per hour electric outage cost.

The cost of the current level of power system reliability is only part of the $0.135/kWh average retail price of electricity in New Jersey. Since the benefit of avoiding electric outage in New Jersey is about $170/kWh, the high ratio of electric service value to the electric service cost helps to explain the consumer demand for a high degree of reliability and resilience in grid-based power supply.

From the reliability perspective, resiliency is the capability of the power supply portfolio to continue to provide consumers with electric services when operating conditions deviate from normal. For example, a deviation from normal winter conditions occurred on 7 January 2014 in the PJM power system. Polar vortex weather conditions drove the power system demand for electricity to an all-time high winter peak demand. These abnormal winter conditions caused significantly higher-than-normal unavailability from natural gas–fired generating units linked, in many cases, to abnormally high natural gas delivery constraints. Under these conditions, the diversity in the generation portfolio allowed nuclear power plants and oil- and coal-fired power plants to back up and fill in for the natural gas–fired resource limitations.

Since the polar vortex in 2014, the New Jersey generation mix has become majority natural gas–fired and the PJM generation mix also has become more natural gas dependent. Much of this broader PJM trend reflects the closure and replacement of base-load generating resources primarily by natural gas–fired generating technologies. Between the polar

7. Marianne Lavelle, "After Hurricane Sandy, Need for Backup Power Hits Home," National Geographic, 29 October 2013, http://news.nationalgeographic.com/news/energy/2013/10/131028-hurricane-sandy-aftermath-need-for-backup-power/, retrieved 13 October 2017.

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

9. Michael J. Sullivan, Josh A. Schellenberg, and Marshall Blundell, *Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States,* Ernest Orlando Lawrence Berkeley National Laboratory, January 2015, https://emp.lbl.gov/publications/updated-value-service-reliability, retrieved 29 August 2017.

vortex in 2014 and the end of 2016, PJM added 11,715 MW of natural gas–fired generating capacity and closed 8,922 MW of coal-fired capacity. A retrospective look at the polar vortex indicated that 5,573 MW of coal-fired capacity that was planned for retirement at the time of the polar vortex provided some of the critical resiliency in PJM during the event.[10]

Backcasting under polar vortex conditions in PJM illustrates the benefits of the resilience provided by the technology- and fuel-diverse electric supply portfolio in place at that time. Figure 4 shows the aggregate consumer hourly load on 7 January 2014 when the polar vortex caused a significant deviation from expected normal operating conditions for the PJM power system and caused PJM to hit a record wintertime peak demand of 141,846 MW.

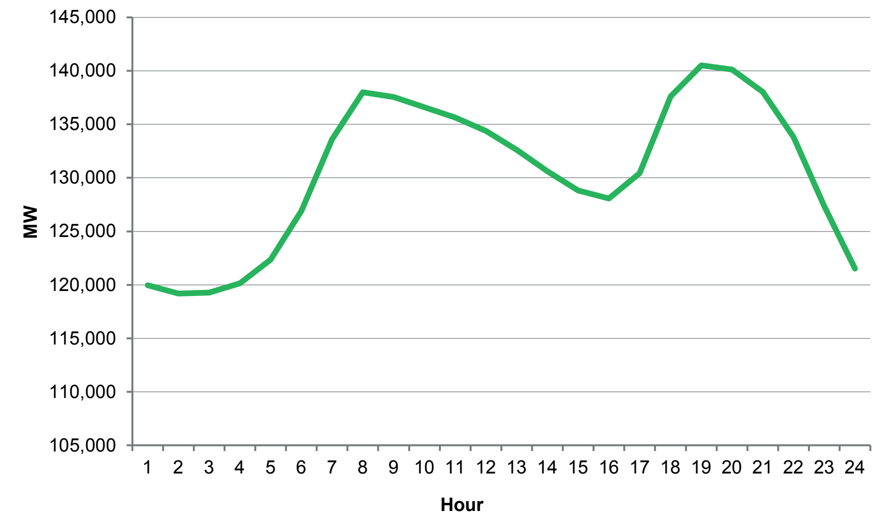
Tables 3 and 4 compare and contrast two PJM net dependable capacity portfolios. The first capacity portfolio shown in Table 3 reflects the actual PJM installed capacity in January 2014, derated by technology and fuel type based on the actual outage rates experienced during the polar vortex on 7 January 2014.[11] The second scenario, shown in Table 4 reflects a change in the installed capacity portfolio to reflect the closure of 4,107 MW of New Jersey nuclear capacity.

Backcasting the outcome during the polar vortex with the alternative PJM power supply portfolio in place while holding all else equal, and exercising the remaining limited PJM emergency operating procedures, results in an expected loss of load across four hours at an average level of about 1 GW, as shown in Figure 5. The benefits of the diverse power supply portfolio that was actually in place and capable of avoiding this loss of load was more than $650 million across PJM and $73 million in New Jersey.

Table 5 shows the new portfolio that reflects the closure and replacement of 8.9 GW of base-load coal capacity with natural gas–fired generation in PJM as well as the closure of 4.1 GW of New Jersey nuclear capacity. Maintaining the forced outage rate of 36% for the incremental 8.9 GW of natural gas–fired capacity in this polar vortex scenario implies that the natural

Figure 4

**PJM hourly load on 7 January 2014**




Source: IHS Markit, PJM © 2017 IHS Markit

Table 3

**PJM net dependable capacity on 7 January 2014**

| Generator fuel type | Installed capacity, 1 January 2014 | | Forced outages | | Other nonforced outages | Net dependable capacity |
|---|---|---|---|---|---|---|
| | MW | Percentage of total installed capacity | MW | Percentage of installed capacity | MW | MW |
| Coal | 75,545 | 41% | 13,700 | 18% | | 61,845 |
| Gas | 53,395 | 29% | 19,000 | 36% | | 34,395 |
| Nuclear | 33,077 | 18% | 1,400 | 4% | | 31,677 |
| Hydro | 8,107 | 4% | | | | 8,107 |
| Oil | 11,314 | 6% | | | | 11,314 |
| Renewables | 956 | 1% | | | | 956 |
| Other | 701 | 0% | | | | 701 |
| Not classified | | | 6,100 | na | 2,412 | (8,512) |
| **Total** | **183,095** | | **40,200** | | **2,412** | **140,483** |

Source: PJM, IHS Markit © 2017 IHS Markit

10. Matthew L. Wald, "Coal to the Rescue, but Maybe Not Next Winter," *The New York Times,* 10 March 2014, https://www.nytimes.com/2014/03/11/business/energy-environment/coal-to-the-rescue-this-time.html, retrieved 13 October 2017.

11. 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.

gas supply chain and deliverability expanded in proportion to the increase in natural gas–fired generation. If the development of pipeline and storage lagged the increase in natural gas–fired generation, then the natural gas–fired power plant forced outage rate would be higher and the size and duration of the associated outage would be greater.

Backcasting the outcome during the polar vortex with the PJM power supply portfolio more closely reflecting today's less resilient power supply mix while holding all else equal, and exercising the remaining limited PJM emergency operating procedures, results in an expected loss of load across seven hours at an average level of about 1.7 GW, as shown in Figure 6. The benefits of the diverse power supply portfolio that was actually in place and capable of avoiding this loss of load was more than $2 billion across PJM and $230 million in New Jersey. The implication is that if PJM faced a similar extreme weather event, New Jersey nuclear plants contribute even more value to the resiliency of PJM.

Table 4

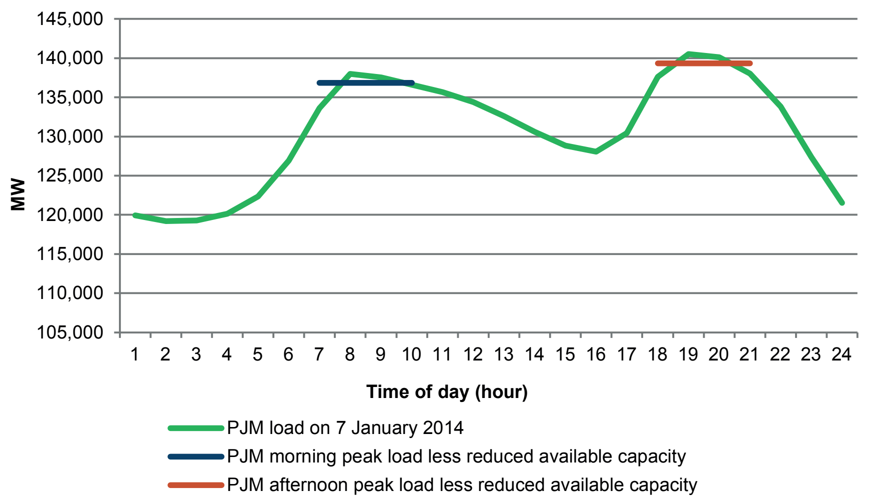
**PJM net dependable capacity on 7 January 2014 less New Jersey nuclear power capacity (4.1 GW)**

| Generator fuel type | Installed capacity on 7 January 2014 less all New Jersey nuclear power capacity (4.1 GW) | | Forced outages | | Other nonforced outages | Net dependable capacity |
|---|---|---|---|---|---|---|
| | MW | Percentage of total installed capacity | MW | Percentage of installed capacity | MW | MW |
| Coal | 75,545 | 42% | 13,700 | 18% | | 61,845 |
| Gas | 53,395 | 30% | 19,000 | 36% | | 34,395 |
| Nuclear | 28,969 | 16% | 1,226 | 4% | | 27,743 |
| Hydro | 8,107 | 5% | | | | 8,107 |
| Oil | 11,314 | 6% | | | | 11,314 |
| Renewable | 956 | 1% | | | | 956 |
| Other | 701 | 0% | | | | 701 |
| Not classified | | | 6,100 | na | 2,412 | (8,512) |
| **Total** | **178,987** | | **40,026** | | **2,412** | **136,549** |

Source: PJM, IHS Markit © 2017 IHS Markit

Figure 5

**Expected loss of load on 7 January 2014 due to retirement of all New Jersey nuclear capacity (4.1 GW)**




Source: IHS Markit, PJM © 2017 IHS Markit

The probability of another polar vortex episode like 2014 may be 1 in 10 years or less. Such a low probability 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 failure may also be 1 in 10 years. Other low-probability but high-impact possible deviations from normal operating conditions include a natural gas storage failure similar to what recently happened at the Aliso Canyon natural gas storage facility as well as a wildfire, heat wave, drought, and physical or cyber attack. In addition, the political risks exist that a severe seismic event associated with hydraulic fracturing wastewater injections somewhere in the United States could lead to a widespread ban on hydraulic fracturing for natural gas production. Although the probability of any one of these events 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 these independent risk factors. Further, the consequences of extreme and catastrophic scenarios increase when two or more high-impact events occur simultaneously. The bottom line is that a better than even chance exists 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, and some of the most troubling potential low-probability but high-impact risks exist in the natural gas fuel supply chain. Consequently, the investment in electric system resilience is a prudent response to the aggregate risk profile of low-probability but high-impact disruptive events to PJM normal operating conditions.

Evaluating the benefits of electric system resilience involves assessing a power system's ability to sustain the impact of major risk factors. Such electric system reliability assessments underpin the development of power system configurations capable of sustaining, adapting, and recovering from the most disruptive excursions from normal operating conditions.

Prudent planning of power system capacity reserves needs to reflect resilience considerations. The resources available to instantaneously match electric supply and demand all involve uncertain availability at any point in time. Therefore, providing reliable electric service requires operating with a diverse mix of resources in reserve. A robust reserve uses diversity to mitigate potential deviations from normal operating conditions affecting the availability of a given generating technology or fuel source. For example, an operating reserve made up entirely of natural gas–fired resources supplied from a common pipeline could provide reliable operating capacity levels under normal pipeline operating conditions. However, the reserve would not be resilient to a pipeline disruption. By contrast, a diverse operating reserve comprising dual-fueled capacity (pipeline natural gas and on-site liquid fuel inventory) would be capable of providing reliable available capacity that is also resilient to a potential significant deviation from normal natural gas pipeline operating conditions.

Table 5

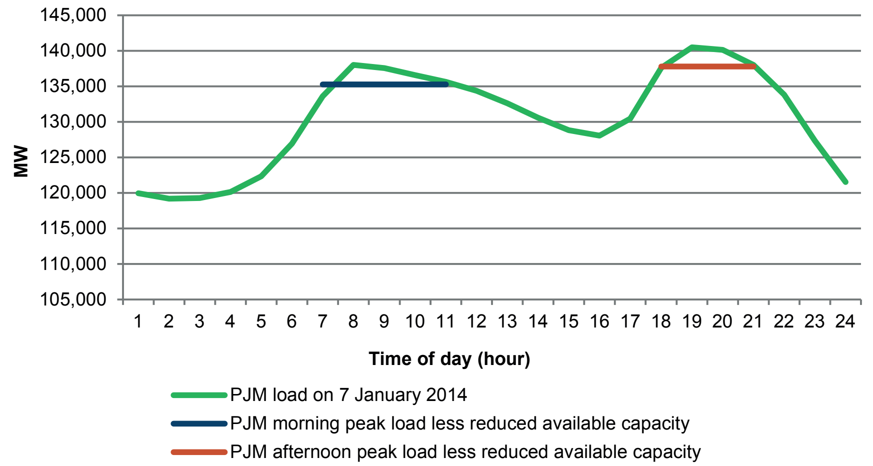
**PJM peak capacity analysis for 7 January 2014: Lower base load and no New Jersey nuclear power capacity (4.1 GW)**

| Generator fuel type | Installed capacity on 7 January 2014 less all New Jersey nuclear power capacity (4.1 GW) | | Forced outages | | Other nonforced outages | Net dependable capacity |
|---|---|---|---|---|---|---|
| | MW | Percentage of total installed capacity | MW | Percentage of installed capacity | MW | MW |
| Coal | 66,622 | 37% | 12,082 | 18% | | 54,540 |
| Gas | 62,317 | 35% | 22,175 | 36% | | 40,142 |
| Nuclear | 28,969 | 16% | 1,226 | 4% | | 27,743 |
| Hydro | 8,107 | 5% | | | | 8,107 |
| Oil | 11,314 | 6% | | | | 11,314 |
| Renewable | 956 | 1% | | | | 956 |
| Other | 701 | 0% | | | | 701 |
| Not classified | | | 6,100 | na | 2,412 | (8,512) |
| **Total** | **178,987** | | **41,583** | | **2,412** | **134,992** |

Source: PJM, IHS Markit © 2017 IHS Markit

Figure 6

**Expected loss of load on 7 January 2014 due to retirement of all New Jersey nuclear capacity, and reduction and replacement of 8.9 GW of coal with natural gas–fired generation**




Source: IHS Markit, PJM © 2017 IHS Markit

In an undistorted efficient market outcome, profitable competitive electric generators trying to maximize expected returns would be expected to invest their positive cash flows in resilience capabilities where the expected benefits exceed the costs. By contrast, underinvestment in resilience is a predictable consequence for unprofitable competitive generators with market cash flows suppressed by market distortions. For example, profitable natural gas–fired CC generators would likely contract for more resilient natural gas supply via purchases of firm pipeline capacity or fuel storage facilities. Consequently, current market conditions that suppress cash flows diminish the capability to make these resilience investments. The bottom line is that underinvestment in power supply resilience is a predictable result of market distortions that reduce wholesale electricity market cash flows.

## Negative statewide economic impacts

The microeconomic impacts drive broader statewide impacts that reflect the pace of premature uneconomic nuclear power plant closures generating a cost to the New Jersey economy from diverting capital from other productive uses and increasing the retail price of electricity. The IHS Markit baseline regional economic outlook provides a reference case for evaluating the employment and state GDP impacts of an electricity price shock due to the nuclear plant shutdowns.[12] In the scenario of closing and replacing the power produced by the Salem and Hope Creek nuclear power plants, annual retail electricity prices in New Jersey would increase by an average of 4% from 2013 to 2016. The analysis also incorporates a reduction in direct employment at the two closed nuclear plants to 10% of current levels.

These direct effects of the nuclear plant closures spread through the New Jersey economy in two ways:

- **As businesses pay more for electric power, they reduce their purchases of other inputs from suppliers (indirect effects).** Supplying firms experience lower sales and reduce demands for inputs from their suppliers. Businesses may try to pass some or all of the higher power costs to their customers, depending on conditions in the markets they serve, which results in a decline in sales.

- **As businesses experience reduced sales and higher costs, they reduce employment levels and payroll expenditures, either directly by eliminating jobs at facilities in New Jersey or indirectly by moving activities to other states (induced effects).** In the short run, New Jersey businesses reduce the number of in-state jobs. In the long run, they move jobs or expand activities to other states. Payroll declines lead to drops in local expenditures of disposable income by affected workers. Because households incur higher electricity prices, with disposable incomes remaining fixed in the short run, they will have to reduce spending for other discretionary items such as entertainment, food, and clothing. The negative impacts will be higher among low-income households that pay proportionately more for electricity than the average household.

Together, these effects will result in lower production, employment, income, and consumption in New Jersey.

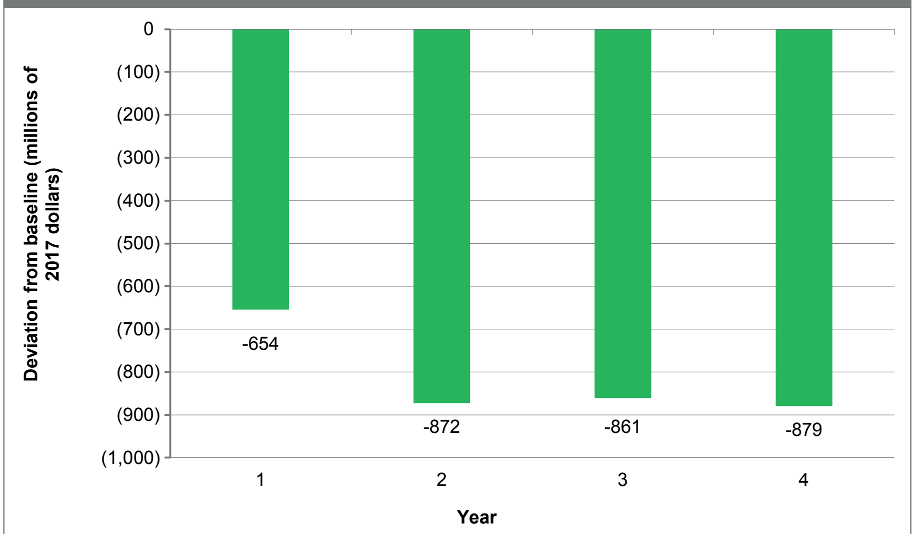
The IHS Markit forecasting model for New Jersey captures the econometric relationships between economic variables and simulates total net change in the levels of economic activity in the state. In other words, the model incorporates the net impact of the direct, indirect, and induced effects. The economic impacts are cumulative as businesses and households make dynamic adjustments to the higher electricity prices over time.

### Impact on real GSP

Figure 7 shows that higher power prices resulting from the closure of the Hope Creek and Salem nuclear power plants lower real GSP in New Jersey by about $820 million in 2017 prices, or 0.14% of potential annual baseline output. Businesses will face the dual challenge of higher operating costs in conjunction with decreased demand for their products and services. Employment will decline as businesses eliminate or relocate jobs to reduce costs. The employment drop will also result in a decline in wage and salary earnings that lowers disposable income. Consumers will reduce discretionary consumption levels when faced with higher power bills.

Figure 7

Impact of nuclear plant shutdown on New Jersey real GSP




Source: IHS Markit © 2017 IHS Markit

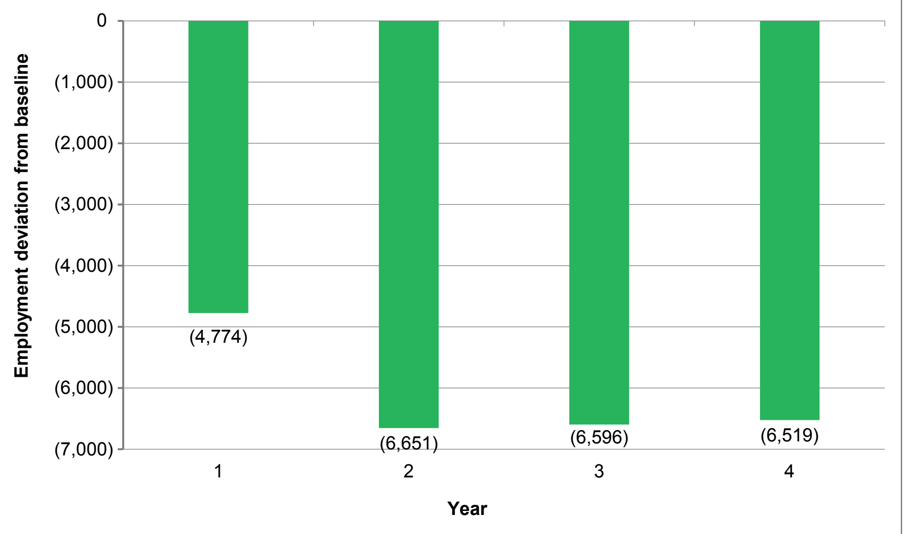
12. The IHS Markit baseline regional outlook reflects the retail price and employment impacts of the anticipated closure of the Oyster Creek nuclear generating station.

### Impact on employment

Figure 8 shows that the premature retirement of the Hope Creek and Salem nuclear plants would reduce total employment by 6,100 jobs annually relative to the reference scenario. It also shows that employment drops continue in year 2 through year 4, indicating that businesses affected by persistently higher electricity prices will make continual adjustments, such as reducing jobs in New Jersey or moving jobs to other states.

Figure 8

Impact of nuclear plant shutdown on New Jersey employment



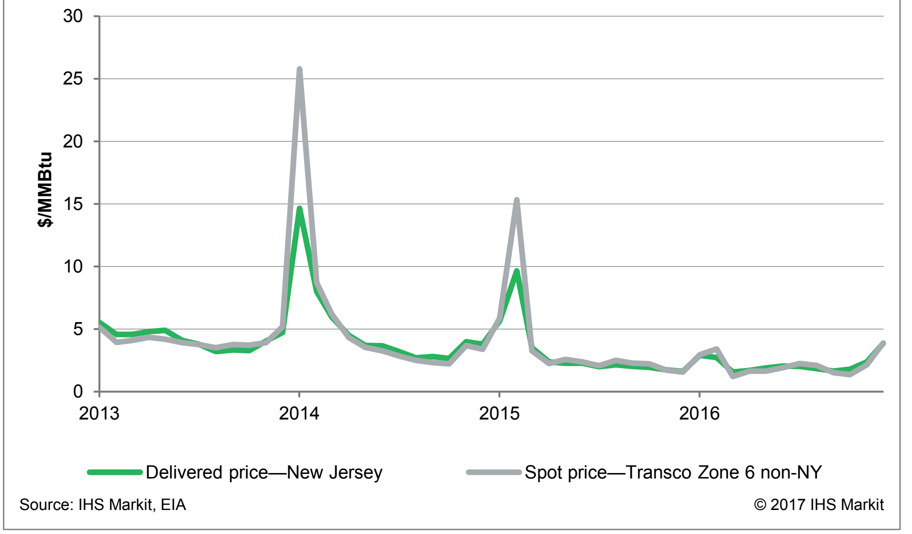

Source: IHS Markit © 2017 IHS Markit

## More varied monthly power bills

One of the cost components of consumer monthly electricity bills is the cost of energy purchased by PJM LSEs. Backcasting indicates that the energy cost component of New Jersey consumers is sensitive to the delivered price of natural gas. This price varied considerably from 2013 to 2016. The spot price of natural gas at the New Jersey pricing hub (Transco Zone 6 non-NY) spiked at more than $25/MMBtu in January 2014 during the polar vortex episode. Figure 9 shows the monthly variability of New Jersey spot and delivered natural gas prices across 2013–16.

Figure 9

Average spot price at Transco Zone 6 non-NY and average delivered price of natural gas to the New Jersey power sector, 2013–16




Source: IHS Markit, EIA © 2017 IHS Markit

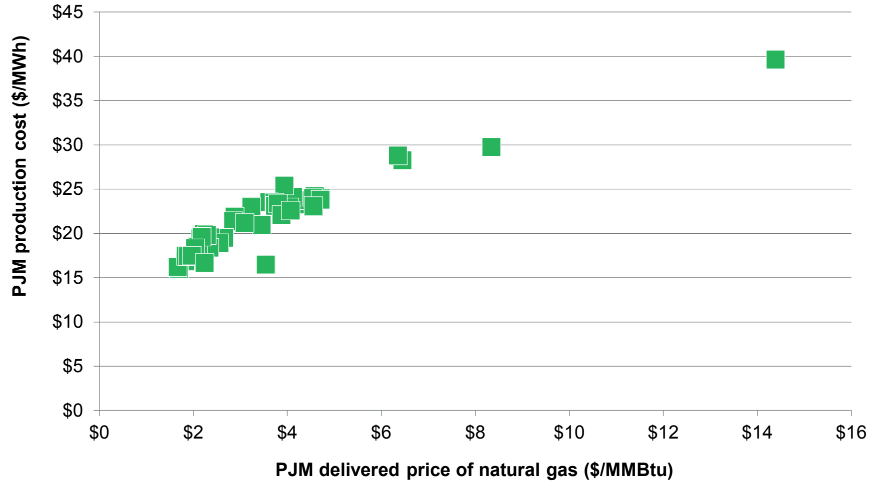
Figure 10 illustrates the sensitivity of the changes in the PJM monthly average cost of production per megawatt-hour to the changes in monthly average delivered natural gas prices. The increase in PJM production costs were greatest in 2014, when natural gas market conditions produced an average annual delivered price of natural gas of $4.58/MMBtu and a monthly average price high of $14.39/MMBtu.

The linkage of PJM electric production costs to natural gas prices means that LSE purchases of electric energy at LMP prices will also fluctuate as the fuel component of incremental variable costs of electric production changes. Backcasting shows that nuclear generation in the PJM supply portfolio mitigates some of the production cost variability in PJM, driven primarily by natural gas price changes. Since the energy cost is one of the components of the New Jersey consumer monthly power bill, the reduction in the variability of the energy component lessens the variability in monthly power bills. The implication is clear—the premature closure and replacement of the Salem and Hope Creek nuclear power plants results in not only an expected increase in monthly power bills but also an expected increase in the monthly variation in consumer power bills.

The premature closure of the Oyster Creek nuclear power plant and the replacement of its output with a 15%/85% mix of renewable and natural gas–fired generation increase the annual PJM natural gas–fired generation share and, thus, increase the exposure of overall PJM variable production cost per kilowatt-hour to the greater variability of delivered natural gas prices. As Table 6 shows, the closure and replacement of the Oyster Creek nuclear power plant produces a 2% greater variability (standard deviation) in monthly PJM variable electricity production cost per megawatt-hour compared with the actual variability during 2013–16. Similarly, the closure and replacement of the Salem and Hope Creek nuclear generation stations increases annual PJM natural gas–fired generation by about 15% and increases the variability in PJM monthly variable production costs per megawatt-hour by an additional 11%.

Figure 10

**PJM monthly production cost per megawatt-hour change versus delivered price of natural gas, 2013–16**




Source: IHS Markit, EIA © 2017 IHS Markit

Table 6

**PJM market outcomes: Backcast from 2013 to 2016**

| Scenario | Monthly standard deviation in variable production costs ($/MWh) |
|---|---|
| Actual | 4.25 |
| No Oyster Creek | 4.33 |
| No Oyster Creek, Salem, or Hope Creek | 4.82 |

Source: IHS Markit, EIA © 2017 IHS Markit

Consumers reveal a preference for stable and predictable monthly electricity bills. For example, the widespread deployment of smart metering technologies enabled the expansion of time of use pricing that reflects the underlying real-time variability of the marginal cost of electricity production. Although voluntary pilot programs indicated some consumer interest, when broader implementation initiatives of time-differentiated price schemes went under way and provided consumers with the choice of more varied real-time pricing, the vast majority of consumers chose to remain with the more stable and predictable traditional retail power pricing schemes.[13]

The consumer preference for stable and predictable monthly power bills means that consumers value having the Salem and Hope Creek nuclear power plants in the power supply portfolio to provide resilience in PJM monthly production costs to changes in the delivered natural gas prices. How much this resilience is worth can be estimated by assessing the cost to replace the resilience to natural gas price changes that the Salem and Hope Creek nuclear plants provide to PJM production costs. Resilience of PJM electricity production costs to natural gas price changes can be accomplished through the use of financial instruments that hedge the price of natural gas to produce the same overall PJM production cost variability.

Hedging natural gas prices with financial instruments can be accomplished in a variety of ways. Hedging strategies can employ long-term contracts for natural gas supply with fixed or indexed prices, as well as employ futures contracts of varying terms along with call options or other derivatives. A simple hedging strategy could employ natural gas price call options. Purchasing a call option provides 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 B 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 to 2016, employing a

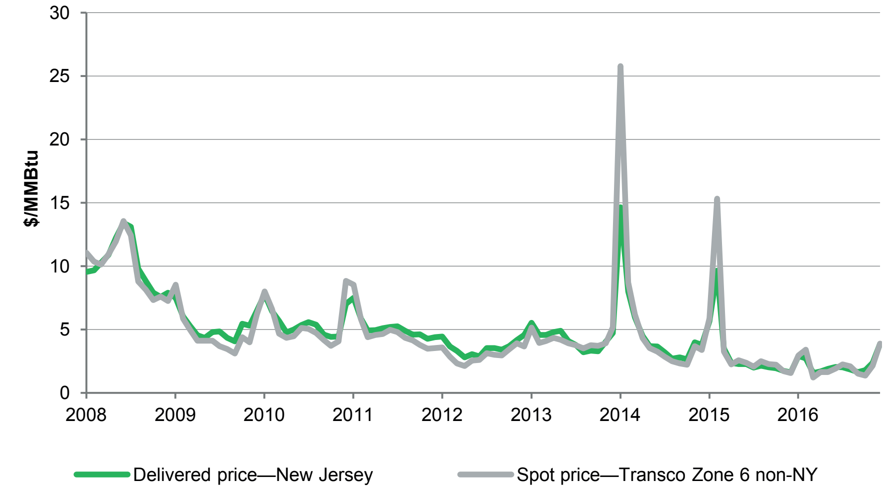
13. See the IHS Markit Multiclient Study *The "Smart Grid Narrative" and the "Smarter Grid": Revolution versus Evolution—Which Way Forward?*

strike price set to limit the price paid for natural gas to a level 50% above the three-month trailing average delivered price of natural gas across PJM. 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. The assessment indicates that hedging PJM natural gas prices across 2013 to 2016 with options involves an average cost of $11.2 million to reduce the variability of monthly PJM production cost variability by 1%.

To put this estimate of hedging costs into perspective, Figure 11 shows monthly data from January 2008 to December 2016 for the average delivered price of natural gas to power generators in New Jersey along with the spot price of natural gas delivered to New Jersey at the Transco Zone 6 non-NY pricing point. The delivered cost of natural gas to power generators reflects a mix of spot purchases along with prices hedged by contracts and financial instruments. As the price patterns indicate, the partially hedged average delivered prices are much lower during the brief but extreme price spikes but are a bit higher on average across all months. Since the delivery points are geographically close, the primary difference in these price series can be interpreted as revealing the cost of hedging natural gas spot prices to reduce the variability of the delivered price of natural gas.

Figure 11

**New Jersey monthly average delivered natural gas prices and Transco Zone 6 non-NY spot prices, January 2008–December 2016**




Source: IHS Markit, EIA © 2017 IHS Markit

Table 7 shows differences in the variation and price level between the New Jersey average monthly delivered natural gas price and the Transco Zone 6 non-NY spot price from January 2008 to December 2016. As Table 7 shows, the higher average price level and the lower price variability of the delivered prices compared with the spot indicate an implicit $0.003/MMBtu cost to reduce natural gas price variability by 1%.[14]

Table 7

**Comparison of the New Jersey average delivered price of natural gas to the power sector and Transco Zone 6 non-NY spot prices, 2008–16**

| Comparison: Price and variation | Average monthly delivered natural gas price to New Jersey ($/MMBtu) | Average monthly Transco Zone 6 non-NY spot price ($/MMBtu) | Difference ($/MMBtu) | Percentage |
|---|---|---|---|---|
| Average monthly price | 4.43 | 4.36 | 0.07 | |
| Variability in monthly prices (standard deviation) | 2.67 | 3.42 | (0.76) | (22%) |

Source: IHS Markit, EIA © 2017 IHS Markit

The analyses indicate that the cost to hedge PJM natural gas prices as a substitute for the stability that Salem and Hope Creek provide to the variable production cost in PJM is $77–112 million per year. This amount is the cost required to keep the month-to-month variation in power bills the same as the PJM base case in which Salem and Hope Creek continue to operate. Such a hedging strategy would benefit all PJM consumers. Therefore, if New Jersey consumers paid their share, the cost to New Jersey consumers would be about $8.6–12.6 million per year.

14. To reduce variability in monthly spot prices by 22% costs $0.07/MMBtu. Therefore, to reduce spot price variability by 1% costs $0.003/MMBtu ($0.07/MMBtu * 0.01/0.22).

## Environmental impacts

Closing the 3,500 MW of nuclear capacity at Salem and Hope Creek reduces nuclear generation in PJM by about 28,750 GWh/y. The equivalent firm capacity replacement involves 3,469 MW of natural gas–fired CC plus 344 MW of wind and 13 MW of solar producing the same amount of energy, with natural gas–fired generation providing an annual average output of 27,622 GWh. With an average of 1,003 lbs of $CO_2$ emissions per megawatt-hour for natural gas–fired CC generation, the annual increase in electricity sector $CO_2$ emissions is 12.6 MMt. To put this into perspective, New Jersey electric generation emitted 19.4 MMt in 2015 and 16.1 MMt in 2012.

The social cost of carbon is an estimate of the economic value of alterations in human health, ecosystems, agriculture, and other facets of life that result from a marginal change in $CO_2$ emissions. Current estimates of the social cost of carbon range from $6 to $75 (2014 dollars) per metric ton.[15] The midrange estimate is about $42 (2014 dollars) per metric ton. Applying this midrange estimate to the $CO_2$ emission mitigation associated with the continued operation of Salem and Hope Creek yields an environmental impact value of about $530 million per year.

In addition, the replacement of Salem and Hope Creek with the same mix of renewable and natural gas–fired generation will produce an annual increase in electricity sector $NO_x$ and $SO_2$ emissions of 3,063 metric tons and 118 metric tons per year, respectively.[16] Using the 2016 Cross-State Air Pollution Rule market allowance prices in New Jersey for $NO_x$ emissions of $137 per metric ton and $SO_2$ emissions of $2 per metric ton puts the additional environmental impact cost for these emissions at $420,000 per year.

## Higher New Jersey consumer power bills

Looking back over the most recent four years indicates that if New Jersey nuclear power plants closed prematurely and were replaced by a 15%/85% mix of renewable and natural gas–fired resources, then electricity production costs across PJM would be higher. Further, the current underlying basis for the New Jersey LMP differential to the rest of PJM would diminish because the New Jersey SRMC of electric production would be similar to the rest of PJM.

PJM market outcomes from 2013 to 2016 provide a base case to evaluate the impact of closing some or all of the nuclear power generating plants in New Jersey. Backcasting PJM electricity sector outcomes across 2013–16 with all conditions held constant, except with the New Jersey nuclear power plants closed and replaced by a current PJM new supply pipeline mix of 15%/85% renewable and natural gas–fired generation, results in an increase in average overall PJM production costs. Therefore, the PJM base case for backcasting holds all else constant but closes and replaces the Oyster Creek nuclear power plant. The closure and replacement of the Salem and Hope Creek nuclear generating stations results in an additional $1,059 million average annual production cost increase. Table 8 shows the backcasting results.

Closing the New Jersey nuclear power plants and replacing the output with a 15%/85% mix of intermittent renewable and natural gas–fired generation makes the generation cost profile of New Jersey similar to the rest of PJM. As a result, the premature closure of the Salem and Hope Creek nuclear power plants results in a loss of the New Jersey LMP differential to the rest of PJM.

Backcasting indicates that the incremental cost associated with prematurely closing and replacing the Salem and Hope Creek nuclear units would have typically added 0.16 cents per kWh to the overall PJM average cost of electric production. If transmission constraints did not exist in PJM, all LMP prices across PJM would increase equally by 0.16 cents per kWh. However, owing to the transmission constraints in PJM, certain lower-SRMC resources can be shared only locally because congestion prevents the export of lower-cost power to zones with higher LMP prices. For example, in 2016 transmission constraints in PJM contributed to New Jersey LMP prices that were lower than LMP hub prices in western PJM more than 70% of the time.[17] This meant that lower-SRMC resources in New Jersey, largely the nuclear units, could

15. 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), doi: https://doi.org/10.1093/reep/res015.

16. Numbers are calculated based on electric generation $NO_x$ and $SO_2$ 2014 emission data from the Environmental Protection Agency's National Emissions Inventory, natural gas consumed by the electric power sector in 2014 from the EIA's "Table 2.6 Electric Power Sector Energy Consumption," and a natural gas CC heat rate of 7,100 Btu/kWh.

17. In 2016, hourly LMP prices in the PSEG, JCPL, and AECO zones were at least 5% lower than the PJM Western Hub day-ahead LMP prices.

not export enough of their lower-cost power to the rest of PJM to equilibrate prices. As a result, LMP power prices in New Jersey were on average 0.3 cents per kWh lower than the rest of PJM, with an average delivered natural gas price of $2.13/MMBtu in 2016. The premature closure and replacement of the Salem and Hope Creek nuclear power plants would eliminate the basis for the LMP differential, reflecting the nuclear versus natural gas–fired generation SRMC differential arising from the existing transmission constraints. In this case, the closure would eliminate an average 0.38 cents per kWh differential in favor of New Jersey consumers, reflecting the typical average delivered natural gas price of $3.29/MMBtu of 2013–16.[18]

Table 8

**Backcast of PJM market outcomes, 2013–16**

| Scenarios | 2013 | 2014 | 2015 | 2016 | 2013–16 average |
|---|---|---|---|---|---|
| **Actual** | | | | | |
| Annual retail sales (GWh) | 670,813 | 672,428 | 670,457 | 663,711 | 669,352 |
| Average annual real retail price (cents per kWh) | 9.94 | 10.32 | 10.42 | 10.35 | 10.26 |
| **No Oyster Creek** | | | | | |
| Total annual production cost change (millions, 2015 dollars) | 173 | 209 | 118 | 100 | 150 |
| Percent change in average real retail electricity price | 0.22 | 0.26 | 0.15 | 0.13 | 0.19 |
| **No Oyster Creek, Salem, or Hope Creek** | | | | | |
| Total annual production cost change (millions, 2015 dollars) | 1,371 | 1,610 | 989 | 867 | 1,209 |
| Percent change in average real retail electricity price | 1.78 | 2.03 | 1.29 | 1.14 | 1.56 |
| **No Salem and Hope Creek versus no Oyster Creek** | | | | | |
| Total annual production cost change (millions, 2015 dollars) | 1,198 | 1,400 | 871 | 767 | 1,059 |
| Change in cost (cents per kWh) | 0.18 | 0.21 | 0.13 | 0.12 | 0.16 |

Source: IHS Markit, EIA © 2017 IHS Markit

Altogether, the impact of the higher PJM average cost of electric production and the loss of the LMP differential would increase the cost of New Jersey wholesale electricity by $5.4/MWh under operating conditions similar to 2016 and fuel costs reflecting the four-year average from 2013 to 2016. This annual cost increase adds $404 million in New Jersey consumer power payments that would involve a 4% increase in the average retail power price. The percent increases to specific customer classes from 2016 retail price levels are summarized in Table 1.

## Opportunities to harmonize New Jersey policy with PJM market operations

New Jersey is at a critical juncture. Doing nothing to address current PJM market flaws and distortions leads to underinvestment in electric production efficiency that moves the electric supply portfolio toward a less efficient and resilient generation mix comprising too many relatively inefficient and fuel-insecure peaking power plants and too few more efficient, fuel-secure base-load resources.

Concerns about addressing wholesale electric market distortions led the US DOE and Secretary of Energy Rick Perry to call for new rules to offset market distortions by allowing for the full recovery of costs of fuel-secure power generation units, including nuclear. Although the specifics of the approach are not yet available, the initiative shows that the discord between public policies and market operations is currently high on the electricity policy agenda.

What happens next will shape electricity markets for decades to come. In particular, a lack of resolution of the current disharmony between public policies and market operations increases the probability that current market distortions will lead to the uneconomic closure and replacement of the Salem and Hope Creek nuclear power plants.

18. Even if transmission constraints cause LMP prices in New Jersey to increase relative to the rest of PJM, the continued operation of the Salem and Hope Creek nuclear power plants would minimize the basis differential because they have an SRMC that is lower than the natural gas–fired generation alternative.

## Appendix A: Performance characteristics of an electric supply portfolio

A cost-effective electric supply portfolio generates benefits by integrating the different cost and performance characteristics of alternative power supply resources. As Figure 12 shows, the current available state of technology for power supply includes a variety of technologies that bring different performance characteristics to an electric supply portfolio.

- **Flexibility/dispatch.** The capability to vary electric output to follow net load through time.
- **Reliable capacity.** The capability to provide capacity when needed.
- **Resilient generation.** The security of the primary energy input supply chain for electric production. For example, fuel inventory at a plant site increases the security of electric supply from short-run fuel supply chain disruptions.

Figure 12

**Performance, cost, and environmental attributes of power production technologies**

| | Power production technologies | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **Power production performance, cost, and environmental attributes** | **Combined cycle** | **Fossil steam** | **Nuclear steam** | **Combustion turbine** | **Hydro: Reservoir** | **Hydro: Run of river** | **Onshore wind (large scale)** | **Solar PV (large scale)** |
| **Flexibility/dispatch** Ability to respond to changes in net load | ◕ | ◕ | ◑ | ● | ● | ○ | ○ | ○ |
| **Reliable capacity** Availability to predictably generate electricity when needed | ● | ● | ● | ● | ◕ | ◔ | ◔ | ◑ |
| **Resilient generation** Dependability and availability of primary energy input | ◑ | ◕ | ● | ◑ | ◑ | ◑ | ◔ | ◔ |
| **Grid support functions** 60 Hz frequency control, reactive power, inertia, etc. | ● | ● | ◑ | ● | ● | ◔ | ○ | ◔ |
| **Storage complementarity** Advantage to integrating storage technologies | ● | ● | ● | ◑ | ◑ | ◑ | ◔ | ◔ |
| **Network integration cost** Incremental power delivery investments | ● | ● | ● | ● | ◑ | ◑ | ◑ | ◑ |
| **Variable cost per megawatt-hour** | ◑ | ◑ | ◑ | ◔ | ● | ● | ● | ● |
| **Fixed cost per megawatt-hour** | ● | ● | ● \| ◔ [1] | ◑ | ● | ● | ◔ | ◔ |
| **$CO_2$ emissions footprint** $CO_2$ emissions per unit of electricity | ◑ | ○ | ● | ◔ | ● | ● | ● | ● |
| **Other environmental impacts** Water use, land use, waste products, non-$CO_2$ emissions | ◑ | ○ | ◑ | ◔ | ◑ | ◔ | ◕ | ◕ |

● More favorable ◑ Neutral ○ Less favorable

1. The first symbol refers to the fixed costs associated with existing nuclear facilities; the second symbol refers to fixed costs associated with new nuclear facilities.
Source: IHS Markit

- **Grid support functions.** The capability to manage grid electricity voltage and frequency, for example, from automatic generation controls.
- **Storage complementarity.** The degree to which linkage to an electric energy storage technology can enhance the cost-effectiveness of the technology in a supply portfolio. For example, reservoir hydro provides the inherent capacity to forgo generation and store water to generate electricity at a later time and, therefore, has less to gain from linking to a storage technology than other technologies. In the case of intermittent renewables, a linkage to storage improves the cost-effectiveness of the power supply, but the improvement in cost-effectiveness is even greater for the linkage of a high-utilization generating technology with a storage technology.
- **Network integration costs.** The impact of a generating technology addition to the supply portfolio on the generating costs of the rest of the power supply mix.
- **Variable cost per unit of output.** The electric supply costs linked to the level of electric energy output.
- **Fixed cost.** The electric supply costs independent of the level of electric energy output.
- **$CO_2$ emission footprint.** The level of $CO_2$ emissions per unit of electric energy output.
- **Other environmental impacts.** The per-unit cost of non–greenhouse gas environmental impacts associated with electric generation.

A cost-effective power supply portfolio aligns the cost and performance characteristics of alternative supply resources to different segments of power system aggregate consumer demand. As a result, a cost-effective power supply portfolio will include power plants with relatively high utilization rates and more efficiency in transforming primary energy into electricity to serve the steady base-load segment of consumer demand.

## Appendix B: Natural gas call option hedging analysis

Consumers in PJM, including New Jersey, will be exposed to greater power price variability owing to the increased reliance on natural gas fuel supply if the Hope Creek and Salem power plants retire. The implicit value to New Jersey consumers of greater power price stability from the continued operation of the Hope Creek and Salem nuclear plants can be comparable to the cost of using financial instruments as a substitute for a more efficient power supply portfolio to hedge the higher production cost variability in the scenario with no New Jersey nuclear generation over 2013–16.

The analysis used natural gas call options to hedge the increased production cost variability in PJM under the less efficient power supply portfolio. Call options are financial instruments that provide holders with the right, but not the obligation, to purchase a certain amount of an underlying commodity on a specified date at a specified price. The specified date is called the *expiration* date, and the predetermined price is called the *strike price*, which sets an upper limit to the future price of the underlying commodity. If, on the expiration date, the price of the underlying commodity is greater than the strike price, the holder of the call option will exercise the right to purchase the commodity at the strike price. Alternatively, if the price of the underlying commodity is less than the strike price on the expiration date, the holder will not exercise the call option. Therefore, natural gas call options place an upper limit on the future price of natural gas and reduce the variability of natural gas and the overall cost of electricity production (as long as some of the call options are exercised).

Backcasting the purchase of natural gas call options on a monthly basis at a rolling strike price set at 1.5 times the average delivered price of natural gas to PJM over the preceding three months reduces the variability (standard deviation) of the variable cost of electricity production in PJM by 23% from 2013 to 2016. The average annual cost of purchasing the natural gas call options based on this strategy is $261 million. Therefore, the average cost to reduce production cost variability by 1% is $11.2 million. Because the production cost variability in PJM is 10% higher in the scenario without the Hope Creek and Salem nuclear plants, the cost to use natural gas call options to achieve the same level of production cost variability is $112 million; New Jersey's share is $12.6 million based on the share of retail sales in PJM in 2016.

The formula used to calculate the theoretical price of an option is shown below and is based on a variant of the Black-Scholes option pricing formula:[19]

$$C_T = \max\{0, (S_T - X)\}$$

$$PV(C_T) = \frac{((F_{0,T}\,N\{a\} - X\,N\{b\}))}{(1+r)^T}$$

$$a = \left(\frac{\ln\left(\frac{F_{0,T}}{X}\right)}{\sigma\sqrt{T}}\right) + \tfrac{1}{2} * \sigma\sqrt{T}$$

$$b = a - \sigma\sqrt{T}$$

Where

$C_T$ is the value of the call option contract.

$S_T$ is the strike price.

X is the natural gas spot price.

$F_{0,T}$ is the forward price.

r is the risk-free rate of return.

19. James Read and Art Altman, "Energy Derivatives and Price Risk Management," in *Pricing in Competitive Electricity Markets,* eds. Ahmad Faruqui and Kelly Eakin (Springer US, 2000). Retrieved from http://www.springer.com/us/book/9780792378396.

$\sigma$ is the volatility of the spot price of natural gas.

N{ } denotes the cumulative probability for a standard normal variable.

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