Ensuring Resilient and Efficient Electricity Generation

The value of the current diverse US power supply portfolio

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About the report

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

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

Ensuring Resilient and Efficient Electricity Generation

The value of the current diverse US power supply portfolio

Executive summary

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

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

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

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

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

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

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

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

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

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

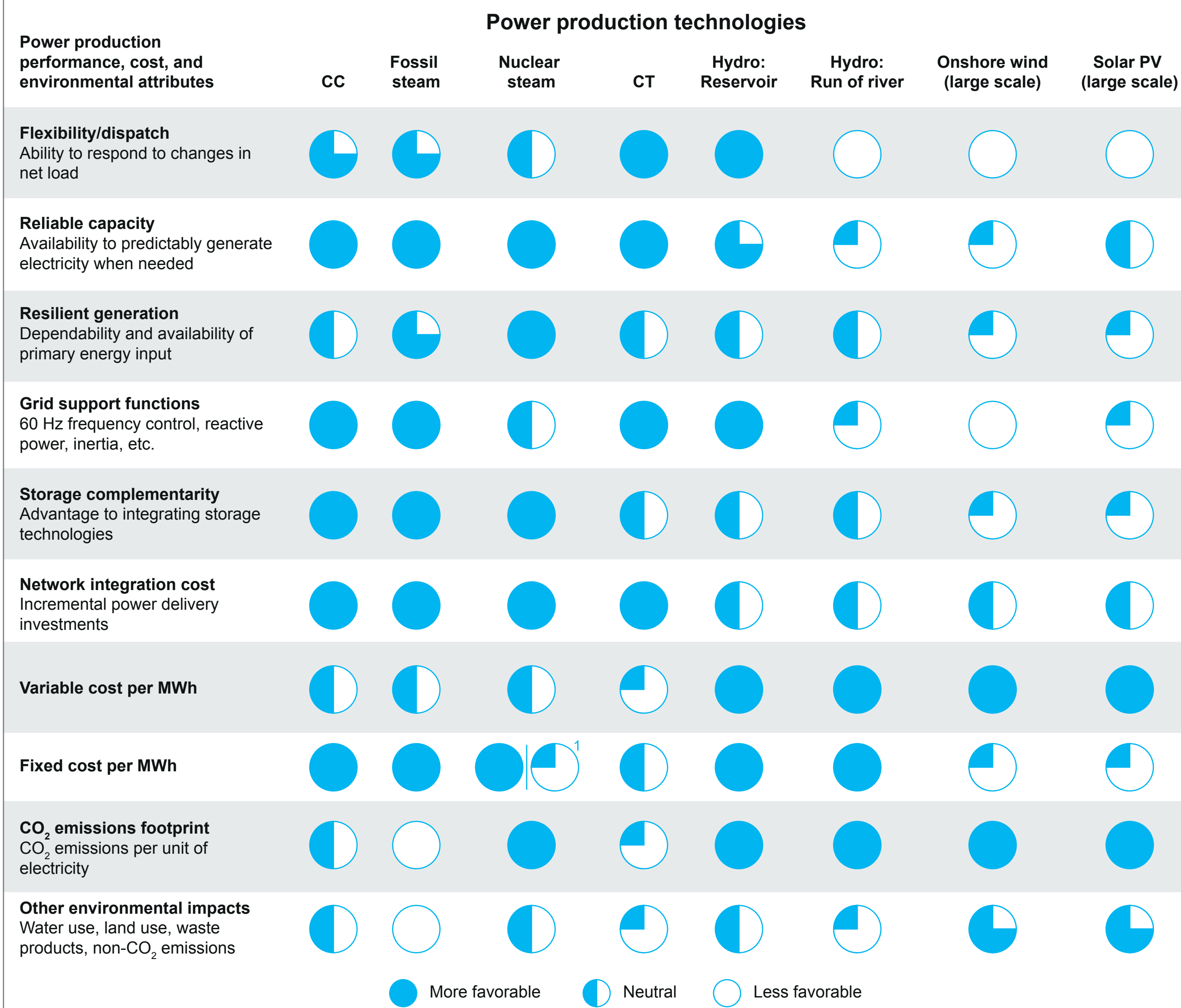
- The 27% retail power price increase associated with the less efficient diversity case causes a **decline of real US GDP of 0.8%, equal to $158 billion** (2016 chain-weighted dollars).
- Labor market impacts of the less efficient diversity case involve a reduction of **1 million jobs**.
- A less efficient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

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

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

Figure 1

Performance, cost, and environmental attributes of power production technologies



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

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

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

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

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

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

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

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

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

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

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

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

Subsidies for specific generating technologies do not reduce, but rather shift, some of the cost of specific electric generation technologies. Federal subsidies shift some costs from consumer power bills to current or future consumer tax bills. In addition, some state subsidies shift costs from consumers with distributed generation resources to those without. Since subsidies shift costs, the result is the development of more subsidized resources than are cost-effective with a level playing field. As a result, an economic rationale exists for market interventions to offset the unintended consequences of the uneven playing field.

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

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

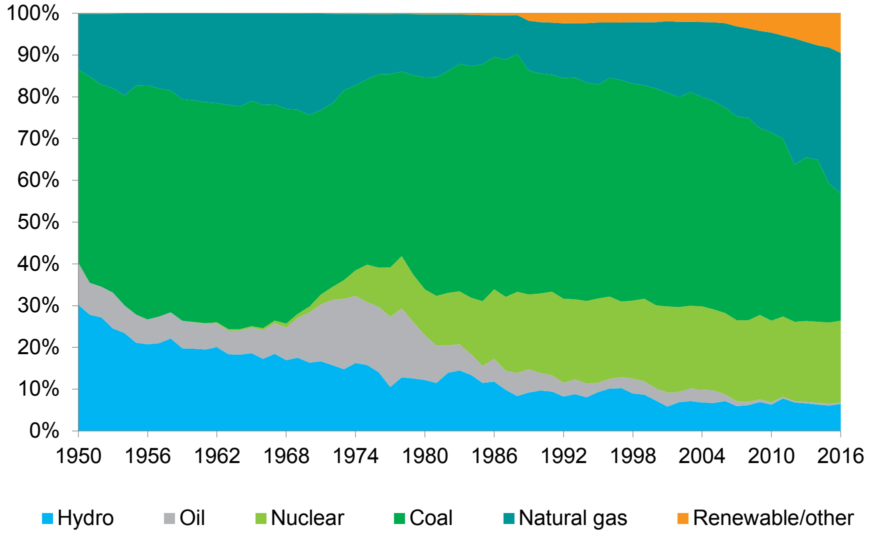
Wholesale electric market price suppression and higher uncompensated operating costs reduce generator cash flows compared with the expected undistorted market outcome. These market distortions continue to undermine competitive power plant investment pro forma. The results are the prolonged cash flow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

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

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

Figure 2

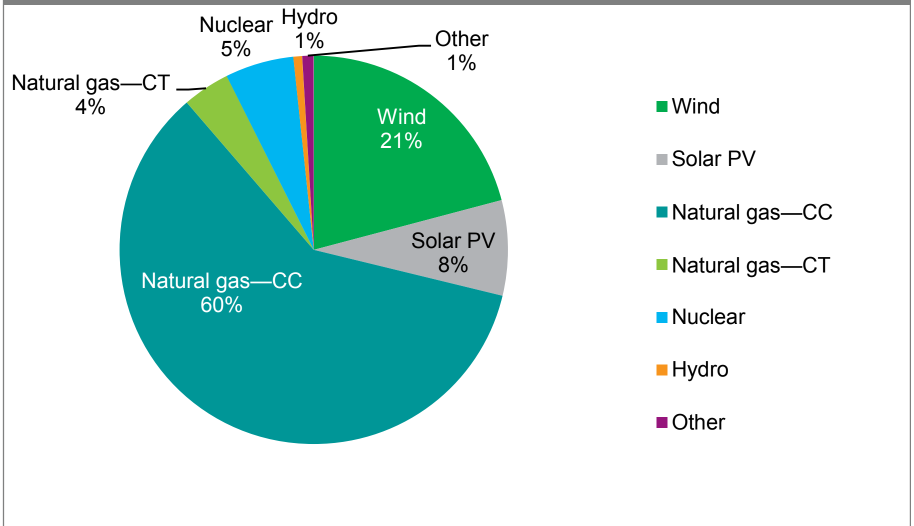
US power generation: Shares by fuel, 1950–2016



Source: IHS Markit © 2017 IHS Markit

Figure 3

US capacity under construction: 38,570 MW



Source: IHS Markit, ABB Velocity Suite

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Ensuring Resilient and Efficient Electricity Generation

The value of the current diverse US power supply portfolio

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Overview

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

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

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

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

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

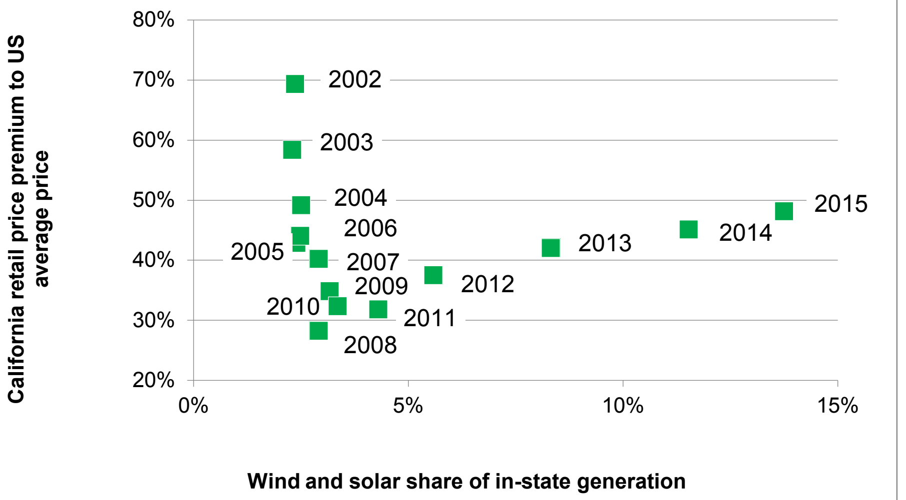
6. Douglas Giuffre, Director; Alex Klaessig, Associate Director; and Benjamin Levitt, Associate Director, contributed to this report.

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

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

Figure 4

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

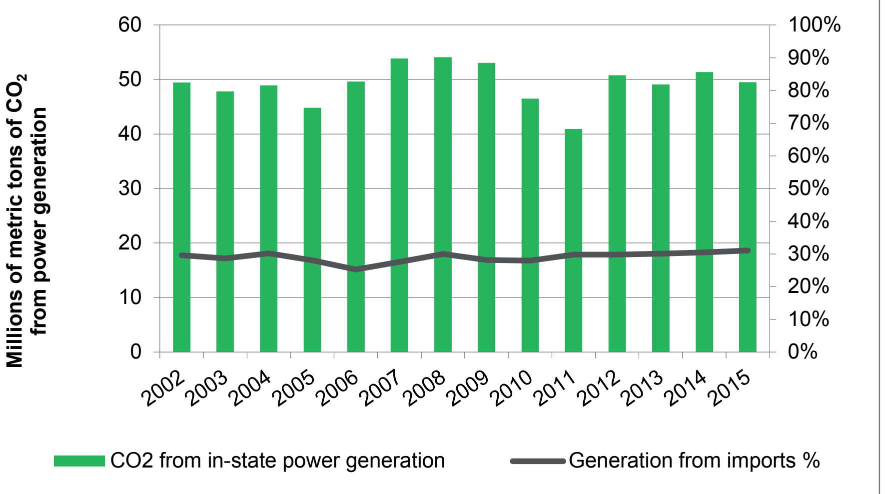


Source: IHS Markit, ABB Velocity Suite © 2017 IHS Markit

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

Figure 5

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



Source: IHS Markit, California Air Resources Board © 2017 IHS Markit

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

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

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

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

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

7. The Brattle Group, *Advancing Past “Baseload” to a Flexible Grid: How Grid Planners and Power Markets Are Better Defining System Needs to Achieve a Cost-Effective and Reliable Supply Mix*, 26 June 2017, retrieved 24 August 2017.

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

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

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

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

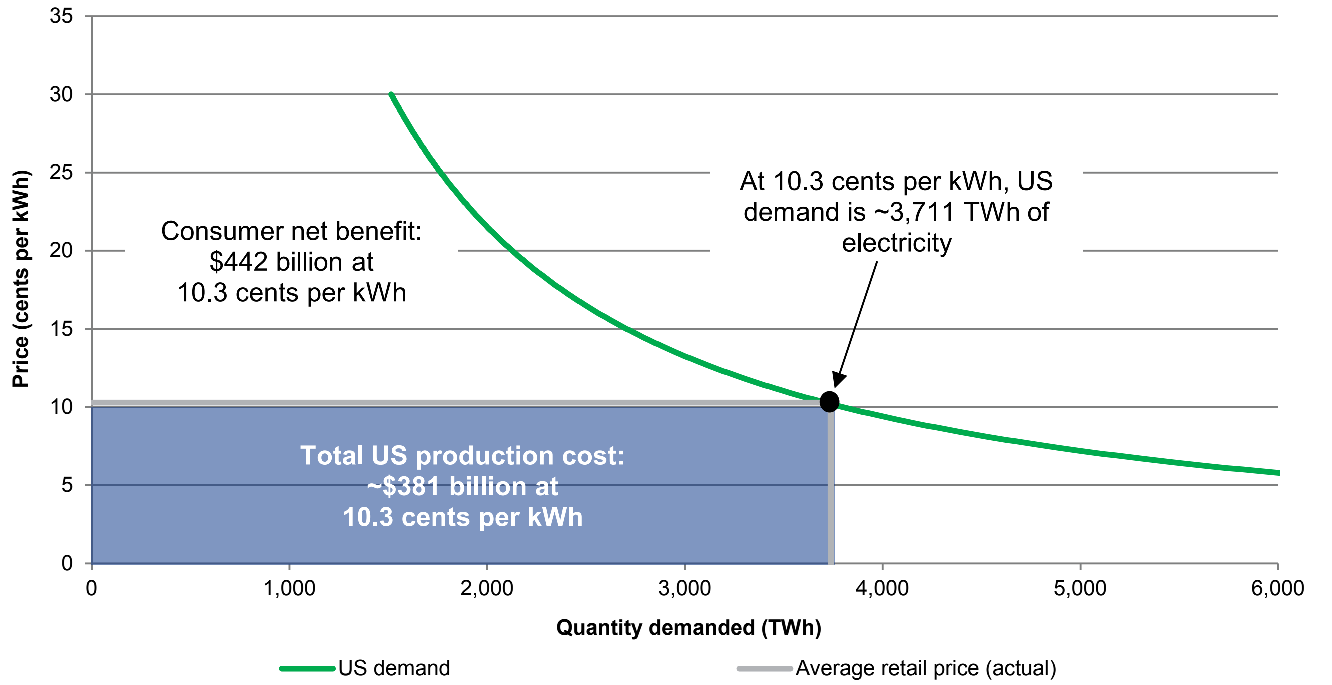
Analysis of consumer electric consumption patterns allows estimation of the relationship between the amounts of electricity that consumers purchase and different price levels—a relationship illustrated by the aggregate grid-based electricity demand curve. Figure 6 shows the estimate of the 2016 US aggregate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

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

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

Figure 6

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

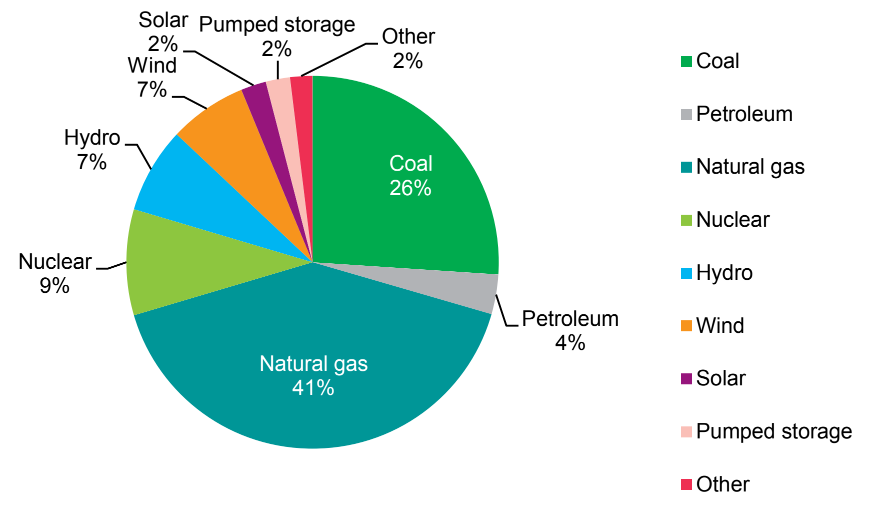


Source: IHS Markit © 2017 IHS Markit

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

Figure 7

US installed capacity (1,073 GW), 2015



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

The implication of the nationwide California retail price is that consumer reactions in the long run would trigger a predictable move along the demand curve from the 3,711 TWh consumption level to the 2,659 TWh consumption level—with all other conditions held constant. Since the aggregate consumer electricity demand curve segments electricity use by price level, this 1,052 TWh reduction in consumer electricity purchases reveals that this segment of consumer demand was worth more than $108 billion to consumers (initial price of 10.28 cents per kWh times 1,052 TWh) but not worth the $161 billion (higher price of 15.31 cents per kWh times 1,052 TWh). Similar predictable reductions in electricity consumption at higher prices indicate the value that consumers place on the electricity consumption all along the demand curve. Therefore, the area under the demand curve from the origin to the actual consumption level provides an estimate of the total value that US consumers put on electricity consumption.

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

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

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

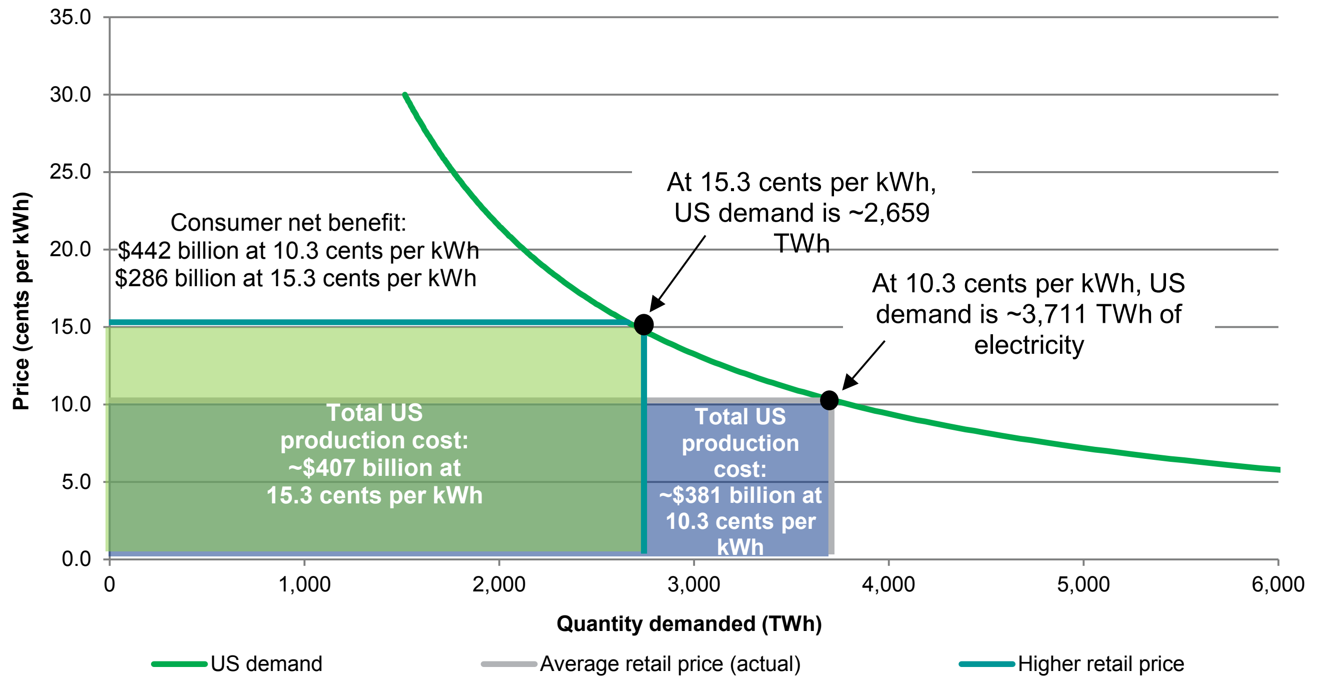
The example of imposing an average retail price increase of 50% to the actual average US retail price in 2016 illustrates how an increase in electricity production costs can reduce the consumer net benefit of electricity consumption. In this case, the 50% retail price increase would cause a 28% reduction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

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

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

Figure 8

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



Source: IHS Markit © 2017 IHS Markit

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

Table 1

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

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

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

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

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

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

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

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

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

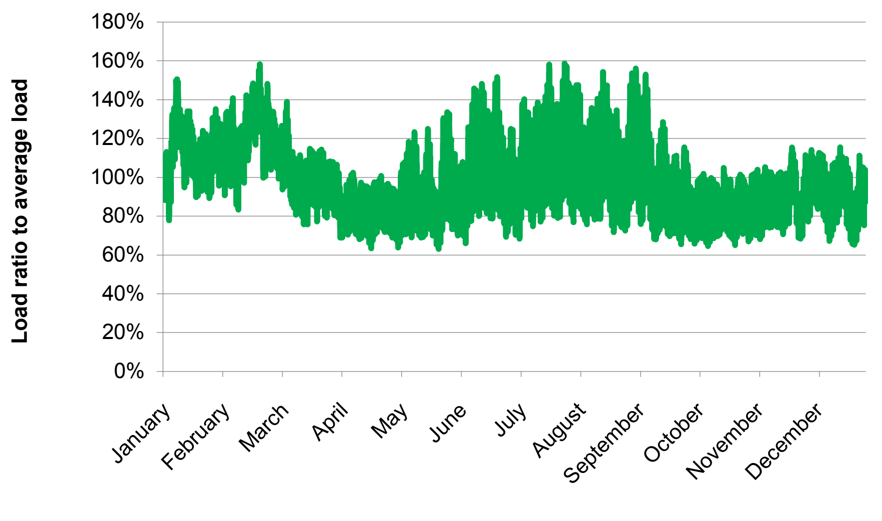
Consumer demands for grid-based electricity reveal a preference to use different amounts of grid-based electricity at different points throughout the year. A number of factors predictably underpin these consumer load patterns throughout the year, such as temperature changes, work schedules, holidays,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

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

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

Figure 9

PJM percent of average load



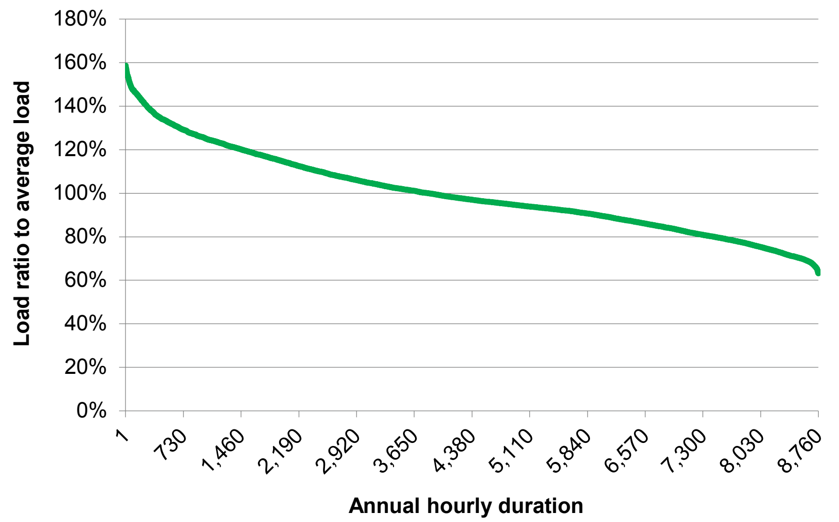
Source: IHS Markit

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

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

Figure 10

PJM load duration curve



Source: IHS Markit © 2017 IHS Markit

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

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

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

Electricity markets incorporate estimates of the revealed consumer willingness to pay to avoid the loss of electric services. For example, in 2014 ERCOT began employing an estimate of the value consumers place on electric service in its implementation of the operating reserve demand curve (ORDC) real-time electric wholesale market intervention to compensate for the reserves employed to reduce the probability of electric system outages. ERCOT employed an estimate of the value of lost load of $9,000/MWh, a value that was about 100 times the 2015 average retail power price of 8.7 cents per kWh. Electric service interruptions, often caused by severe weather, overloading, power station failures, and other issues, add significant costs to consumers. Prior estimates of total annual power outage costs in the United States have exceeded hundreds of billions of dollars per year.[8] Of course the timing and duration of outages affect consumer impacts, but simply increasing the frequency of the typical electric service disruptions in the United States results in about $75 billion per hour of electric service interruption costs.[9]

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Table 2

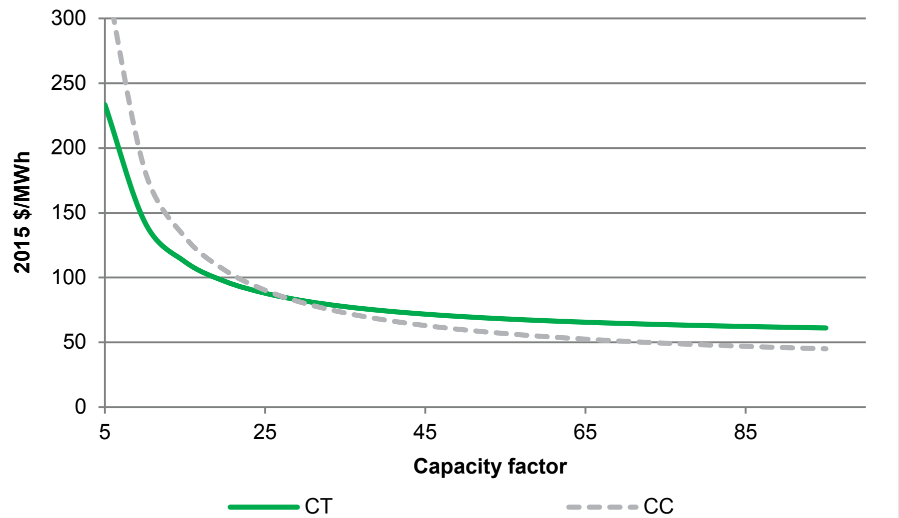
Electric generating technology cost and performance profiles

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

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

Figure 11

Annual LCOE versus capacity factor



Source: IHS Markit

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Although an efficient long-run electricity market outcome can generate adequate cash flows to support the cost-effective and resilient peaking technologies along with cost-effective and resilient higher-utilization load-following technologies, we do not expect an efficient market outcome to involve only investments in flexible generating technologies with varying utilization rates and productive efficiencies. Some segments of consumer demand do not fluctuate through time. When a sufficient number of rival generators compete to supply this stable, base-load segment of the market demand profile, the competitive advantage falls to less dispatch-flexible technologies capable of trading off more up-front capital costs for greater generating efficiency. For example, a CHP technology deployed in an industrial cogeneration application involving the joint production of a steady flow of steam for an industrial process and the associated steady stream of electrical output can rely on inframarginal rents available when the higher SRMC-based bids of the flexible, lower up-front cost generating technologies are setting prices that generate the energy market cash flows that cover the cost-effective investments in the higher up-front capital cost technologies capable of greater production efficiency at high utilization rates. Again, market prices signal cost-effective investment in resiliency. For example, a high-utilization coal-fired power plant faces periodic episodes of fuel delivery interruptions owing to the potential for rivers to freeze and inhibit barge traffic. In this case, the energy market price indicates the potential loss of inframarginal rents, and the capacity market price indicates the potential loss of capacity revenues from fuel supply disruptions. Balancing these expected costs against the cost of holding fuel in inventory provides the basis to determine efficient resiliency from stockpiling fuel.

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

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

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

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

Wholesale electricity market distortions from policy and market disharmony

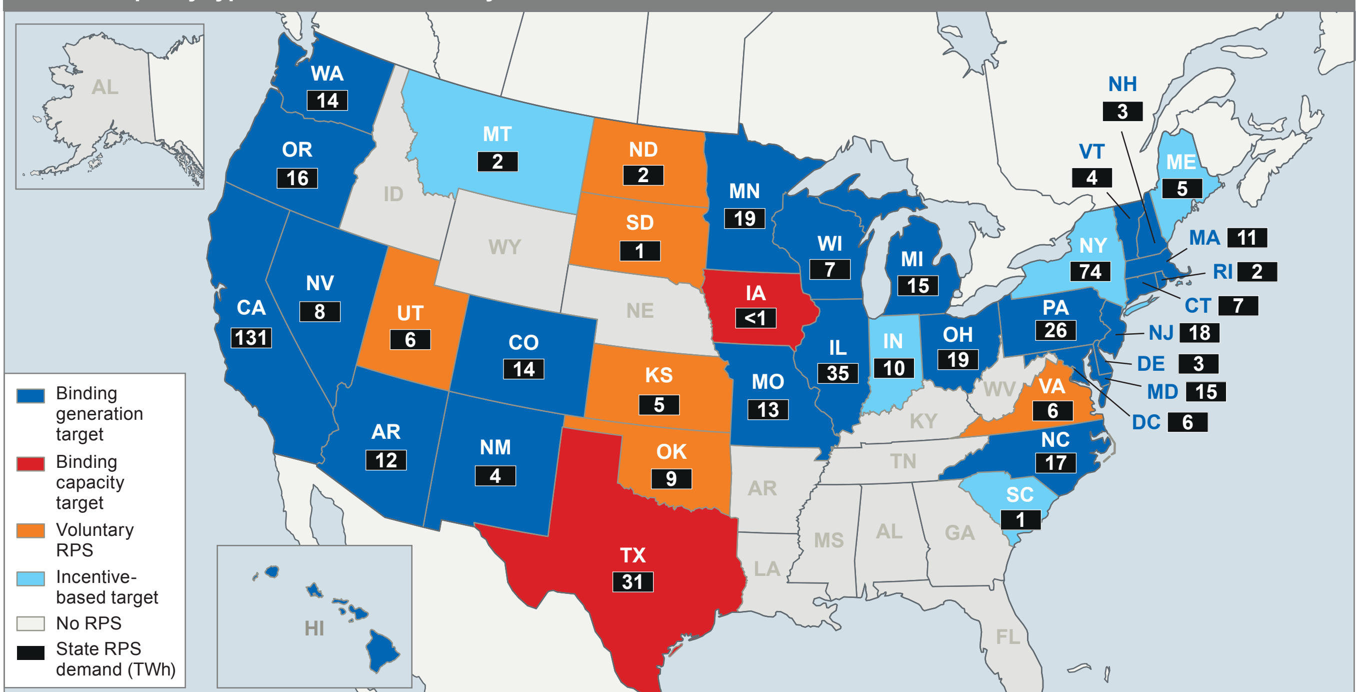
The political process generates electric sector policy at the federal, state, and market level, and the potential exists for this process to produce market interventions that are at odds with the principles of regulation. This lack of harmonization with regulatory principles distorts market outcomes and makes the US electric supply portfolio less reliable, resilient, and cost-effective, thereby reducing the consumer net benefit from electricity consumption. An understanding of market distortions involves contrasting distorted market outcomes to the characteristics expected in a well-functioning wholesale marketplace.

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

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

Figure 12

State RPS policy types and total demand by 2030



Source: IHS Markit / 1694695

Note: RPS = renewable portfolio standard.

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

- **Price suppression.** Whenever policy initiatives drive the addition of zero-SRMC resources beyond their cost-effective level, the power system net-load demand curve shifts leftward when the wind blows or the sun shines and lowers the market-clearing wholesale energy price, all else equal, compared with the undistorted wholesale electricity market outcome.

- **Delayed market adjustments.** Whenever policy initiatives drive the addition of zero-SRMC resources that provide some net dependable capacity toward meeting the peak load plus the reliability reserve requirement, the capacity market price or the ORDC scarcity-based energy prices are lowered from the level conditions would otherwise produce in an undistorted wholesale electricity marketplace.

- **Integration costs.** Policy initiatives that drive more intermittent generation than is cost-effective typically involve intermittent generation variability that is not highly correlated with aggregate consumer consumption temporal patterns and causes the power system net-load factor to decline. This integration of intermittent resource output causes the unit cost of the remaining dispatchable power supply to increase compared with the outcome in an undistorted wholesale marketplace.

- **Risk exposure.** Whenever policy initiatives drive intermittent generation shares and natural gas–fired generation shares to exceed the level associated with a reliable, resilient, and efficient supply portfolio, the exposure to risk factors capable of generating potential significant excursions from normal operating conditions increases compared with the undistorted wholesale market outcome. This elevates the cost of adjustments to the economic dispatch to satisfy security of supply constraints and ensure resiliency to the wider scope of potential disruptions. This market distortion aggravates an existing market flaw in some existing wholesale markets in which price formation rules do not fully compensate resources for the full marginal power system cost of providing security and resiliency.

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

US power supply portfolio retirements and replacements

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

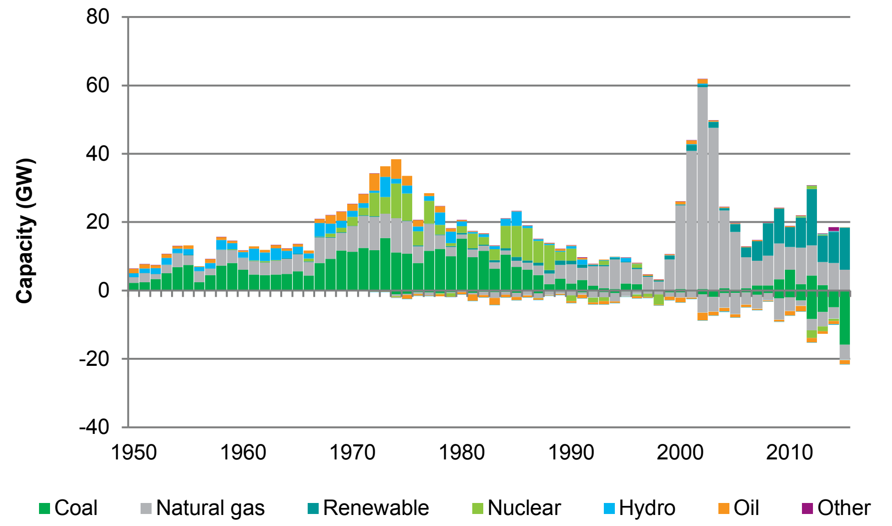
Economic power plant retirements occur in a well-functioning marketplace because market-clearing prices reflect the LRMC of replacement power resources and thus provide a signal for the cost-effective timing to replace existing generation. An existing resource is economic to operate as long as its going-forward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

Figure 13 shows the historical retirement and replacement patterns of US power plants in the power supply portfolio. Some of these retirements and replacements are economic and some are uneconomic. Separating the two types of power supply turnovers involves a comparison of the going-forward costs with the costs of replacement. An uneconomic power plant retirement occurs when a power plant closes and is replaced even though it would have been lower cost to keep it operating. Conversely, an economic power plant retirement occurs when a power plant closes and is replaced by a plant with a lower cost than required for continued operation.

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

Figure 13

US generating capacity additions and retirements, 1950–2015



Source: IHS Markit, ABB Velocity Suite

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Table 3

IHS Markit US power business strategy group companies

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

Source: IHS Markit

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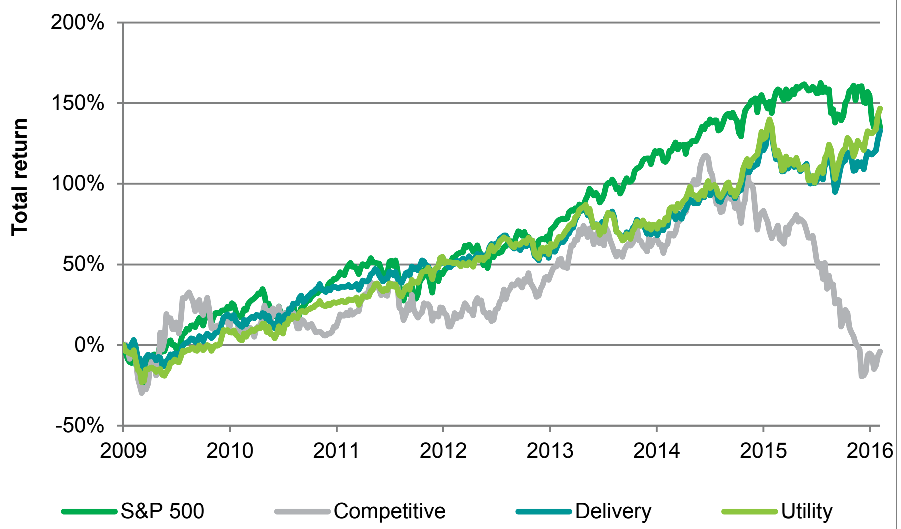
Relative financial performance of select utility business models

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

Figure 14

Power business strategy groups: Cumulative total return, 2009–16



Source: IHS Markit, SNL Financial © 2017 IHS Markit

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

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

Power supply replacement costs

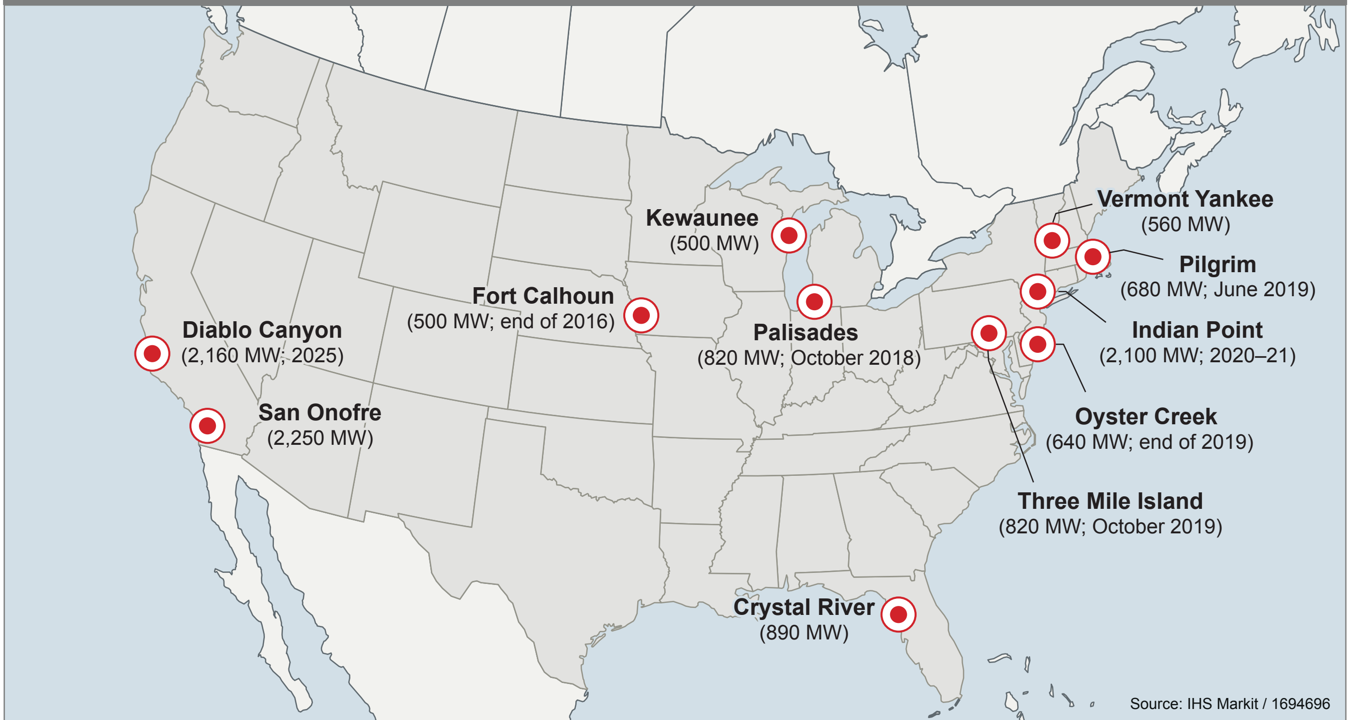
Quantifying the cost of replacing the uneconomic retirement of power plants aligned to the nonpeaking segments of aggregate consumer demand involves developing cost estimates of the annual levelized cost basis to provide equivalent capacity and energy outputs. Replacement can involve a single technology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

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

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

Figure 15

Nuclear plant proposed and completed closures since 2012



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

Table 4

Electric generating technologies cost and performance characteristics

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

Source: IHS Markit, EIA

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

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

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

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

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

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

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

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

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

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

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

Table 5

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

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

Source: IHS Markit, EIA © 2017 IHS Markit

Existing generating resource going-forward costs

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

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

The cost of uneconomic power plant retirements

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

Table 6

Common cost parameters for power plant development

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

Source: IHS Markit, EIA © 2017 IHS Markit

Table 7

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

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

Source: IHS Markit, EIA © 2017 IHS Markit

Table 8

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

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

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

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

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

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

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

Table 9

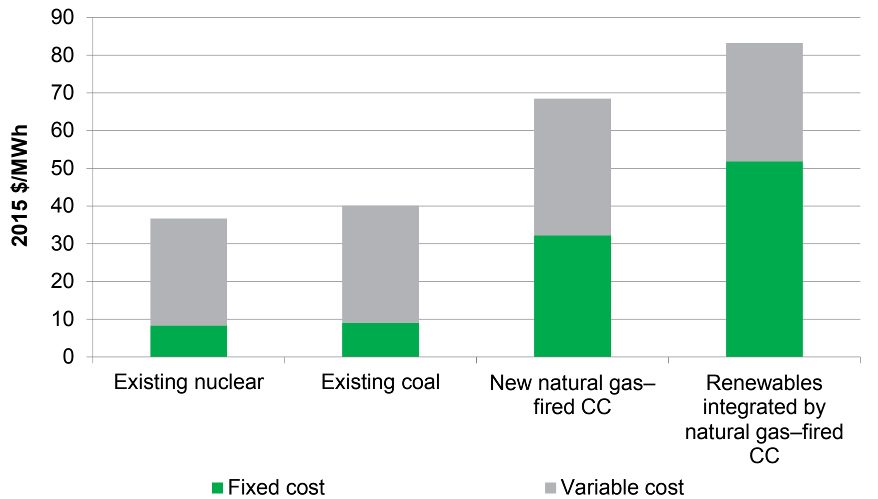
Levelized going-forward costs of existing US power supply portfolio resources, 2015 ($/MWh)

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

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

Figure 16

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



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

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

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

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

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

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

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

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

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

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

Table 10

Current US power supply portfolio versus less diverse case

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

Source: IHS Markit © 2017 IHS Markit

Table 11

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

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

Source: IHS Markit © 2017 IHS Markit

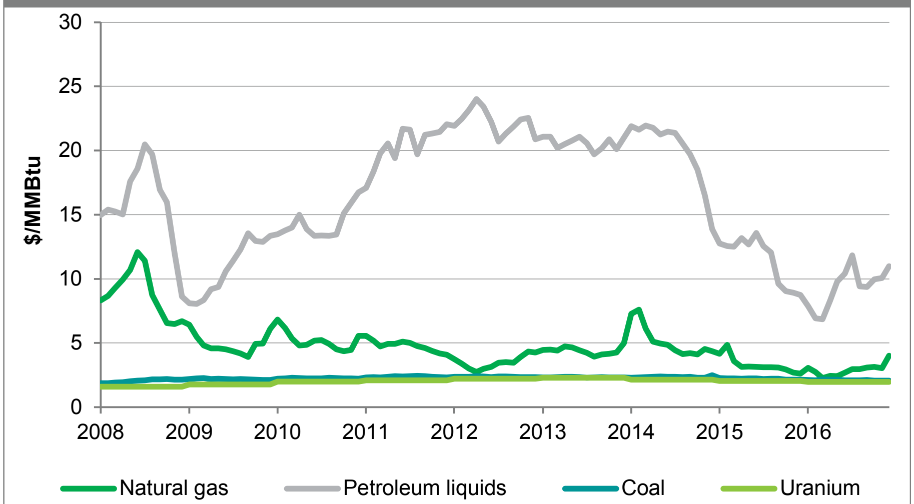
Variation in monthly consumer electricity bills

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

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

Figure 17

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



Source: NEI, EIA © 2017 IHS Markit

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

Incorporating power supply resiliency to known risk factors capable of triggering excursions from normal operating conditions is fundamental to power system strategic planning and reliability standards for power system operations. Contingency planning is central to North American Electric Reliability Corporation standards that are approved by FERC and implemented by regional transmission organizations (RTOs) and ISOs across the United States. An example of such planning is the recent report submitted to the US DOE from the Eastern Interconnection Planning Collaborative (EIPC) that found, "Along with the benefits associated with the use of a relatively clean and cost-competitive fuel, increased reliance on natural gas has exposed the increasing potential impact on bulk power system reliability from events that can reduce or interrupt gas supplies and deliveries." Looking ahead, the EIPC report concludes that, "The increase in gas demand for electric generation coupled with the lack of infrastructure expansions to serve gas-fired generators in certain PPAs [participating planning authorities] raises strategic concerns over pipeline and storage companies' ability to keep pace with the coincident requirements of gas utilities serving residential, commercial and industrial customers as well as the needs of gas-fired generating plants on peak demand days."[19]

Economywide impacts

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

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

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

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

Impact on GDP and employment

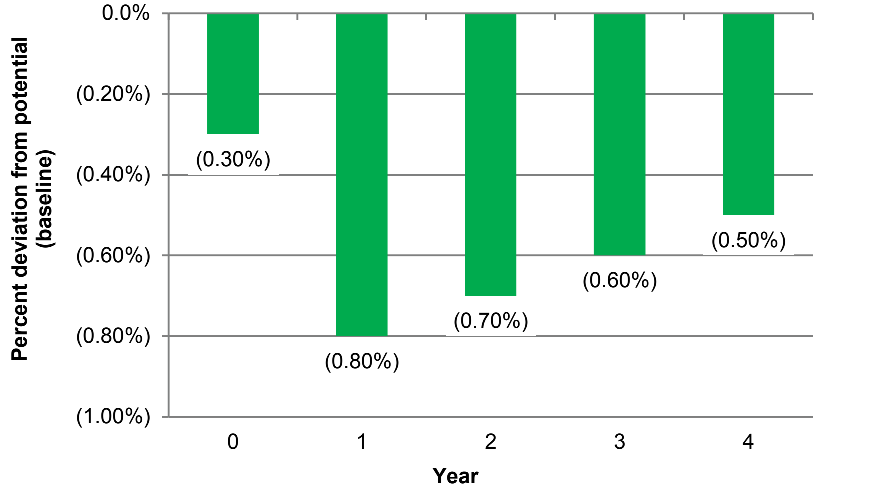
The US economy is a complex adaptive system that seeks to absorb shocks (e.g., increases in prices) and converge toward a long-term state of equilibrium. The simulations conducted for this study do not project that the US economy will fall into a recession because of power price increases but are informative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

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

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

Figure 18

Impact of less efficient diversity case on real gross domestic product



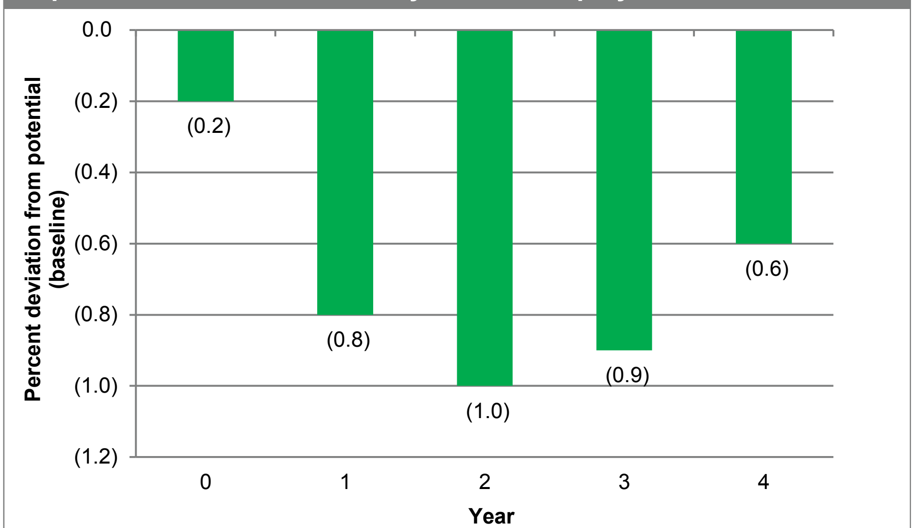
Source: IHS Markit © 2017 IHS Markit

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

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

Figure 19

Impact of less efficient diversity case on employment



Source: IHS Markit © 2017 IHS Markit

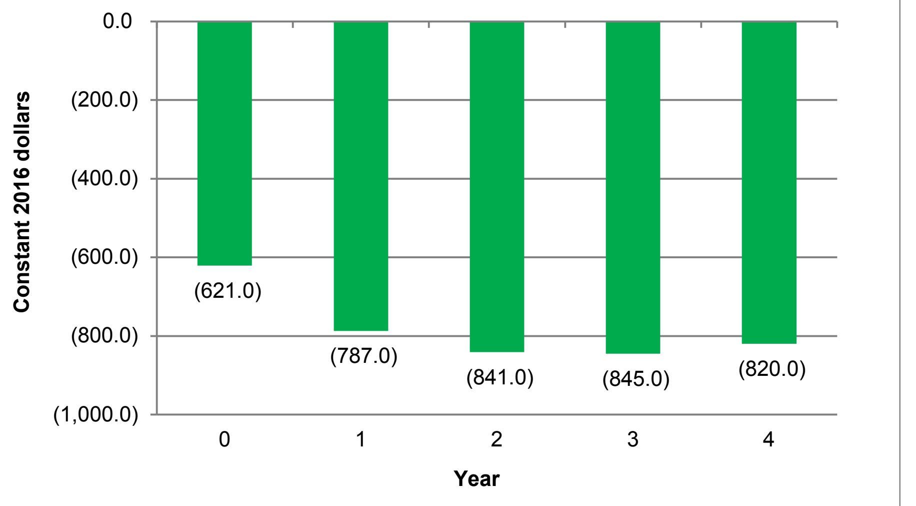
Household disposable income and consumption

Some portion of increases in manufacturers' costs ultimately will be passed on to consumers through higher prices for goods and services. Faced with lower purchasing power, consumers will scale back on discretionary purchases because expected real disposable income per household is lower by approximately $760 (2009 dollars) three years after the electric price increase (see Figure 20). The net impact on consumers reflects labor market conditions. The unemployment rate is now approaching the level associated with full employment, and employed consumers are able to respond to higher prices by demanding higher wages to some degree. On the one hand, this reduces the impact on consumers' wallets from the magnitude from even a few years ago. On the other hand, it exacerbates the inflationary impact on the economy, thereby reducing the Federal Reserve's range of options.

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

Figure 20

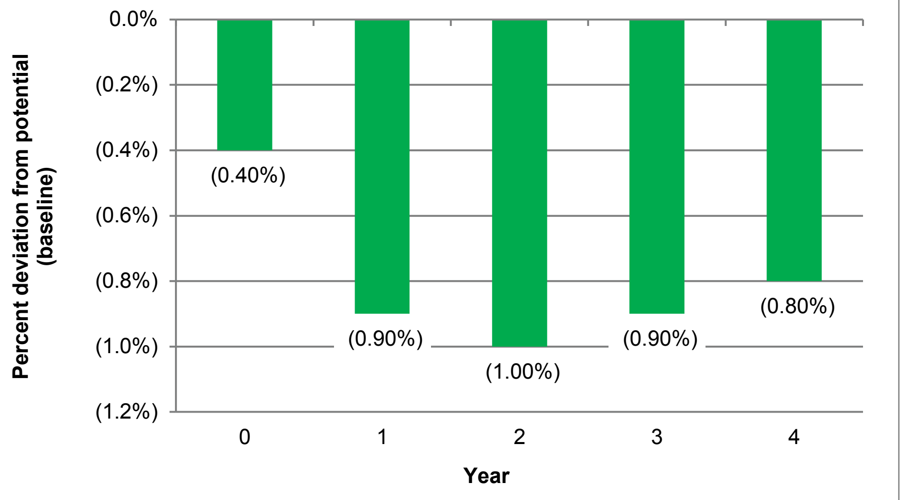
Impact of less efficient diversity case on real disposable income per household



Source: IHS Markit © 2017 IHS Markit

Figure 21

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



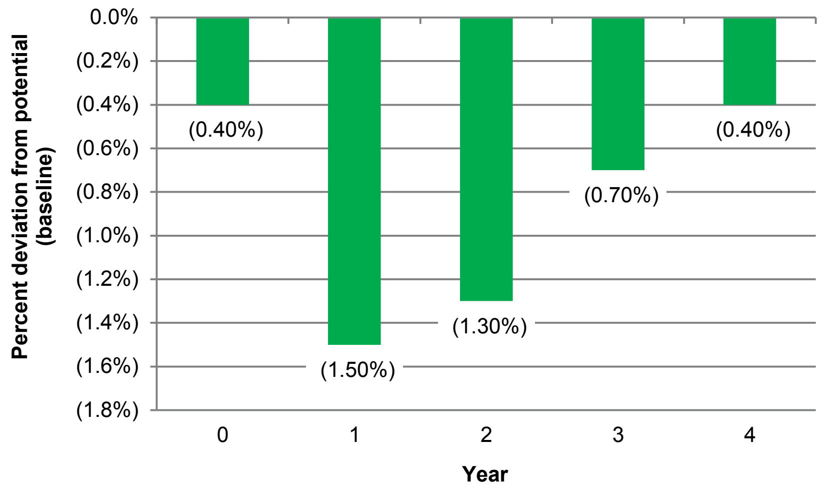
Source: IHS Markit © 2017 IHS Markit

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

Investment

Figure 22

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



Source: IHS Markit © 2017 IHS Markit

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

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

Current electricity sector policy at a critical juncture

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Appendix I: US electric energy demand analyses

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

Residential consumer electric energy demand

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

Equation 1:

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

Where

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

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

β_0 is the intercept.

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

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

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

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

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

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

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

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

e is the error term.

Residential regression results

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

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

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

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

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

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

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

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

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

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

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

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

Commercial consumer electric energy demand

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

Equation 2:

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

Where

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

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

β_0 is the intercept.

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

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

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

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

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

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

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

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

e is the error term.

Commercial regression results

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

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

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

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

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

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

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

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

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

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

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

Industrial consumer electric energy demand

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

Equation 3:

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

Where

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

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

β_0 is the intercept.

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

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

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

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

e is the error term.

Industrial regression results

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

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

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

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

  The estimated long-run price elasticity of demand is negative. The magnitude of the coefficient aligns with previous research. A survey of the literature for the US DOE by Carol Dahl in 1993 found a wide disparity in estimates for both commercial and industrial price elasticities, ranging from –1.03 to –1.94. The estimated coefficient is statistically significant based on conventional metrics. The null hypothesis is that no relationship exists with the dependent variable because the true value of the coefficient is zero. The T-statistic indicates that the probability of a type I error (rejecting this null hypothesis when it is true) is less than 1%.

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

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

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

Appendix II: Electricity storage paradox

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

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

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

Table 12

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

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

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

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

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

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

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

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

Table 13

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

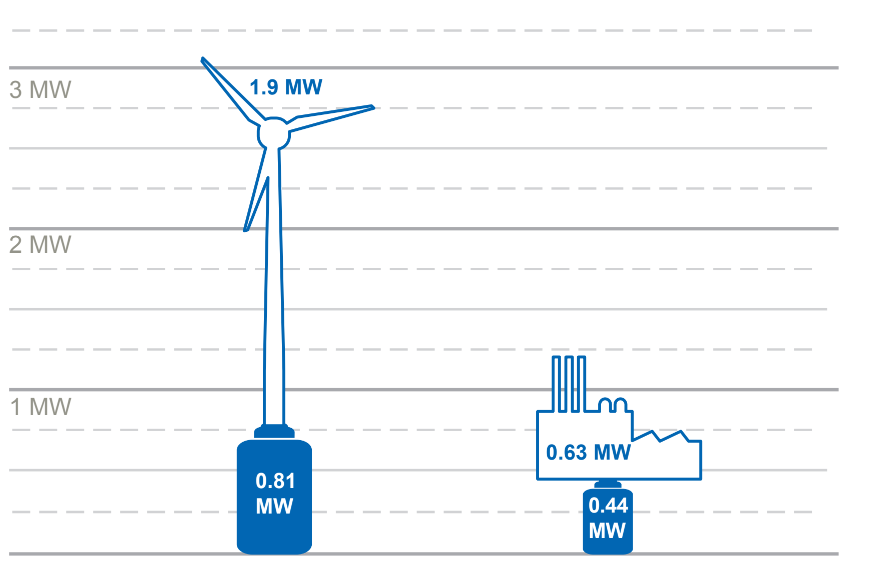
Costs to meet incremental power demand	1.1 MW conventional flexible dispatchable generating technology	1 MW wind turbine technology integrated with 1 MW conventional flexible dispatchable generating technology
Annual fixed cost	$75,000	$280,682
Annual variable cost	$250,000	$118,600
Total annual generating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

Source: IHS Markit © 2017 IHS Markit

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

Figure 23

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



Source: IHS Markit © 2017 IHS Markit:1695666

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

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

Table 14

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

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

Source: IHS Markit © 2017 IHS Markit

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

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

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

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

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

ERCOT

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

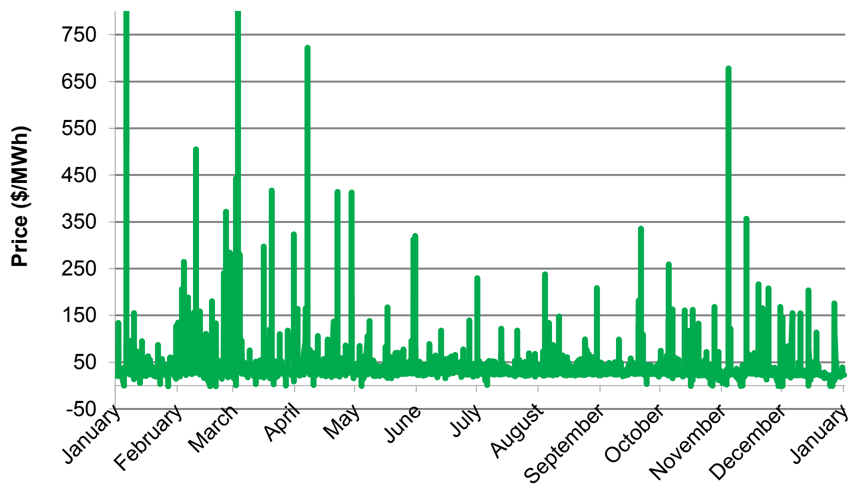
The EIA estimates that the unsubsidized levelized cost for wind entry in the United States is between $41/MWh (2015) and $71/MWh (2015). The above-average wind conditions in Texas put the unsubsidized levelized cost of ERCOT wind entry at the low end of this range, but these cost assessments do not include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

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

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

Figure 24

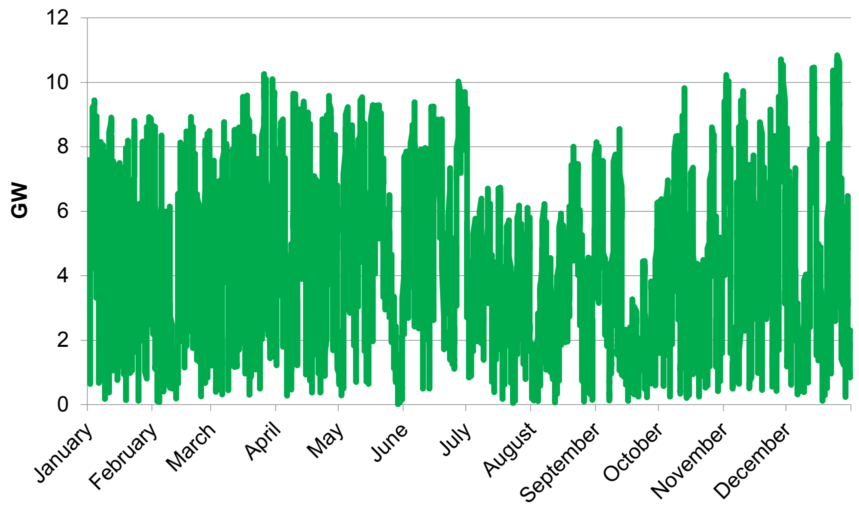
ERCOT: $36/MWh average price, 44 hours of negative prices, 2014



Source: IHS Markit, ERCOT © 2017 IHS Markit

Figure 25

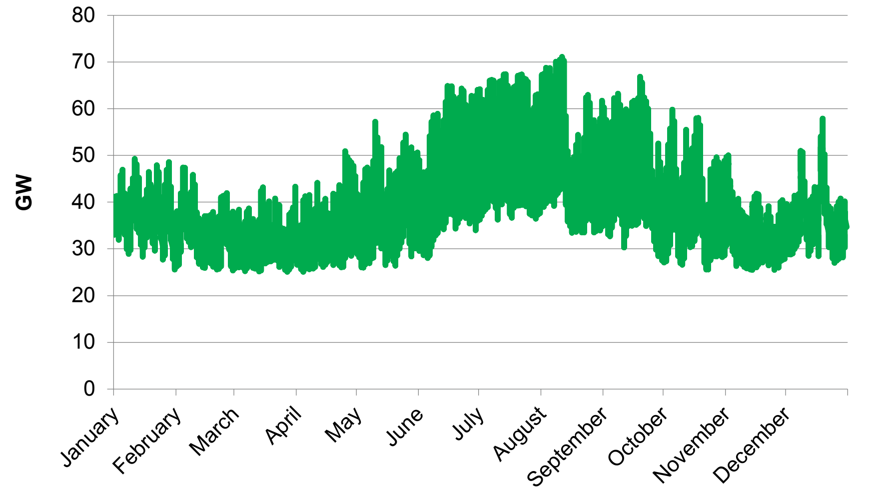
ERCOT hourly wind output, 2014



Source: IHS Markit, ERCOT © 2017 IHS Markit overgeneration conditions that produced the negative ERCOT wholesale prices shown in Figure 24. The bottom line is that the shortfall in ERCOT wholesale market-clearing prices covering the entry costs of unsubsidized wind are even greater when the realized average price reflects price levels when the wind blows or when the incremental generation costs of transmission are also included. The implication is that the ERCOT wind resource generation share exceeds the cost-effective level.

Figure 26

ERCOT aggregate hourly demand, 2014



Source: IHS Markit © 2017 IHS Markit

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

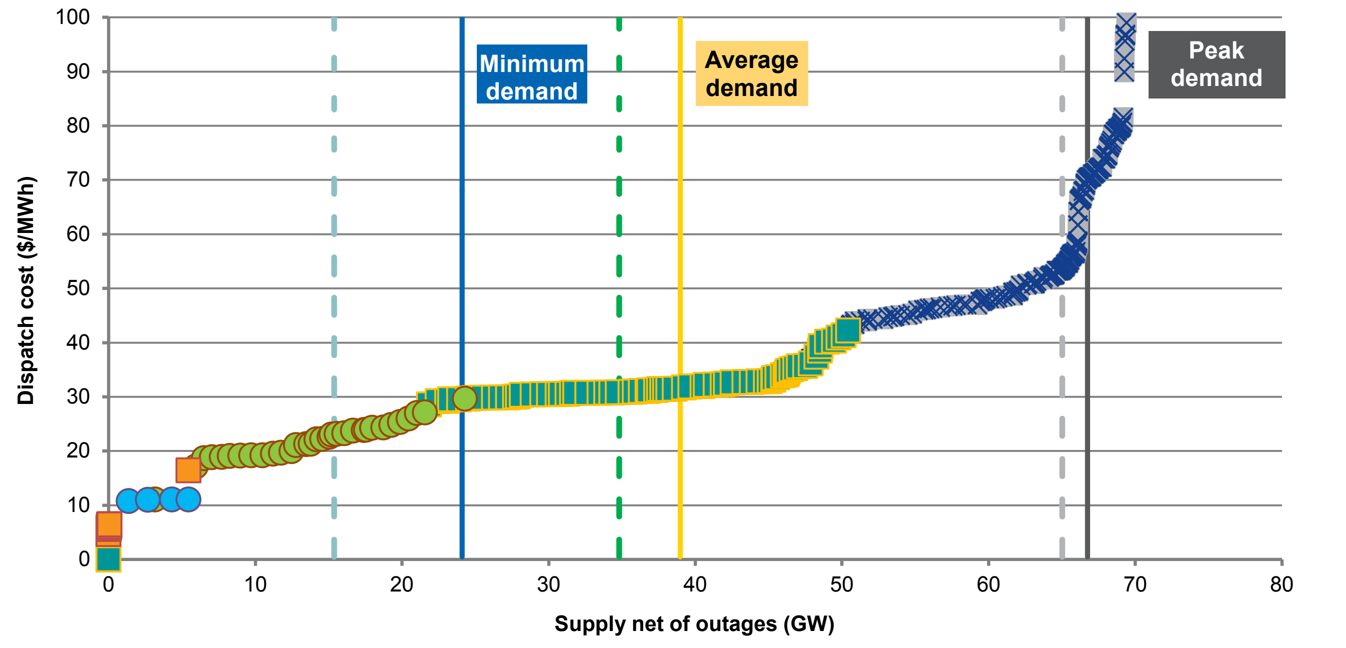
ERCOT wind output suppresses ERCOT wholesale market-clearing prices. This wholesale price suppression can be graphically illustrated for recent interactions between ERCOT supply and demand curves. Figure 27 shows the ERCOT wholesale market supply curve as an aggregation of price-sensitive power supply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

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

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

Figure 27

ERCOT supply curve, 2014



Source: IHS Markit

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

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

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

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

PJM

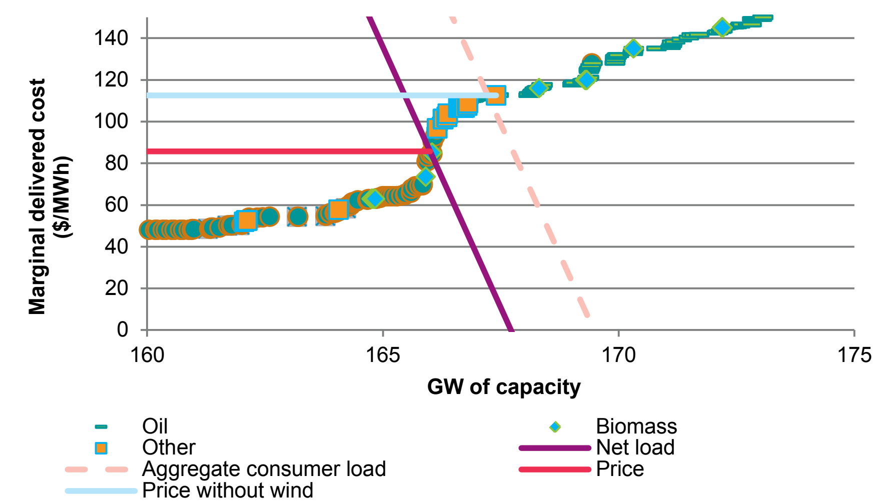
Many states within the PJM electric system mandated renewable generation shares beyond what is cost effective, causing market price distortions. The majority of renewable resource development in PJM involves wind technologies.

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

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

Figure 28

Demand hours: Top 15%



Source: IHS Markit, ABB Velocity Suite, Monitoring Analytics (PJM Independent Market Monitor)

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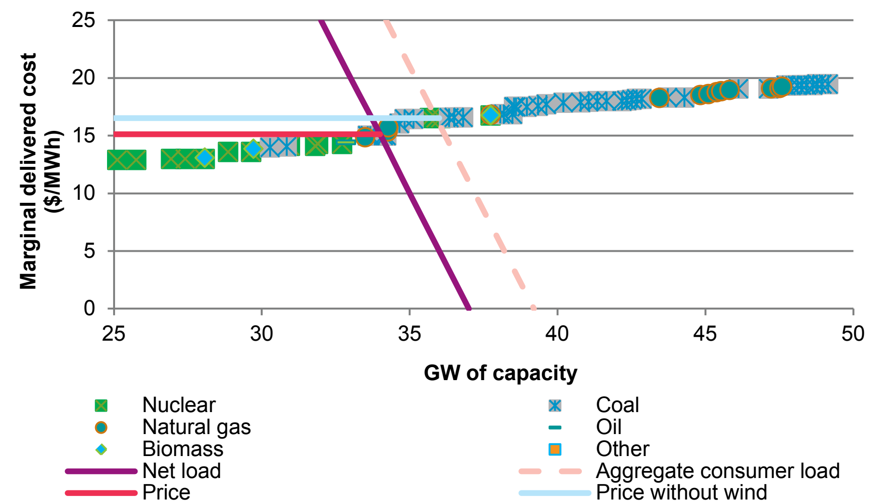
Figure 29

Average price level



Source: IHS Markit, ABB Velocity Suite, Monitoring Analytics (PJM Independent Market Monitor)

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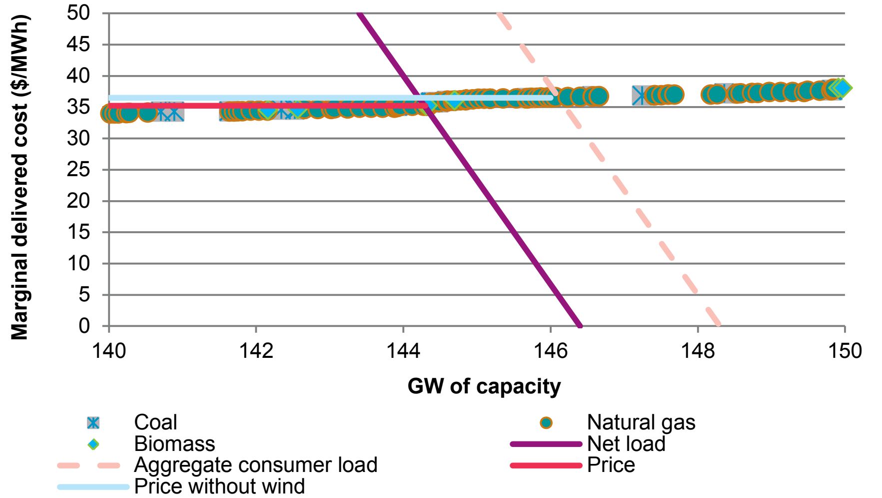
The market demand and supply interactions show that wind output suppressed prices by about 24% during the 15% of the maximum 2015 net-load hours when rival peaking technologies were setting the price. Wind output suppressed prices by about 4% during the 15% of hours around average net load and by around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

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

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

Figure 30

Demand hours: Bottom 15%



Source: IHS Markit, ABB Velocity Suite, Monitoring Analytics (PJM Independent Market Monitor)

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

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

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

Periods of overgeneration and negative market-clearing prices expose an underlying flaw in electricity market price formation. Such conditions caused 25 hours of negative PJM market-clearing energy prices in 2015. During these periods, production cost minimization requires reducing supply or increasing net load from the least-cost options during periods of overgeneration. However, wind-on-wind competition to avoid curtailment involves the opportunity cost of losing the volume-based subsidy. Consequently, the renewable bids reflecting this subsidy generate curtailment bids that lead to more expensive resource curtailment and negative market-clearing prices. Under these conditions, the market-clearing prices do not reflect the positive SRMC of the resources running to provide the security-constrained dispatch for the power system. Such results aggravate the existing problem that adjustments to market-clearing wholesale prices to accommodate the security constraints of generation dispatch do not fully reflect the marginal costs of generating resources operating to satisfy system requirements.

California

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

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

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

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

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

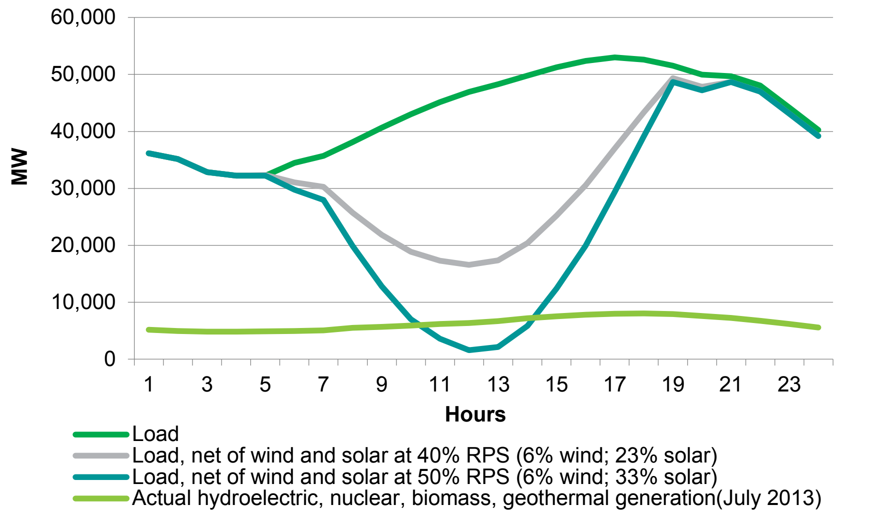
25. SB 350: Golden State Standards, retrieved 24 August 2017.

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

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

Figure 31

California average hourly load, July 2030



Source: IHS Markit, CAISO

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

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

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

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

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

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

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

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

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

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