

Ensuring resilient and efficient PJM electricity supply

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

Appendixes

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Lawrence Makovich
Vice President and Chief Power Strategist

Benjamin Levitt
Associate Director

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Appendix A: US electric energy demand analyses

Quantification of US electric energy demand involves analysis of cross sectional state-level data (50 states plus 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:

$$Y_i = \beta_0 + \beta_1 X_{1i} + \beta_2 X_{2i} + \beta_3 X_{3i} + \beta_4 X_{4i} + e_i$$

Where:

i is the geographic region (state of 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

Table 13 summarizes the regression output. Since all variables are expressed as natural logs, the regression coefficients can be interpreted directly as elasticities of demand. Since price and income differences among states are longstanding, 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-Square statistic indicates that the four independent variables and the constant term forming the estimated equation altogether 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

Table 13

Summary annual residential electricity use per customer

Regression statistics						
Multiple-R		0.893994449				
R-Square		0.799226074				
Adjusted R-Square		0.781767472				
Standard error		0.1280528				
Observations		51				
ANOVA						
	df	SS	MS	F	Significance F	
Regression	4	3.002605812	0.750651453	45.77835404	1.77693E-15	
Residual	46	0.754285897	0.01639752			
Total	50	3.756891709				
	Coefficients	Standard error	t Stat	P-value	Lower 95%	Upper 95%
Intercept	7.620722512	2.53741701	3.003338625	0.004308774	2.513166981	12.72827804
LN (five-year price)	-0.71581224	0.07927539	-9.029438272	9.43334E-12	-0.875385323	-0.556239156
LN (median household income purchasing power parity)	0.114326268	0.216121596	0.528990487	0.599355539	-0.320703941	0.549356477
LN average temperature	0.625971103	0.116847054	5.35718345	2.62763E-06	0.390770182	0.861172023
LN (energy efficiency investment 10-year per customer)	-0.055820828	0.013379153	-4.172224295	0.000132356	-0.082751667	-0.02888999

Note: LN = natural log.

Source: IHS Markit

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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 back casting 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 -0.81.¹

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.

1. 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).

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 range 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 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%.

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:

$$Y_i = \beta_0 + \beta_1 X_{1i} + \beta_2 X_{2i} + \beta_3 X_{3i} + \beta_4 X_{4i} + e_i$$

Where:

i is the geographic region (state or DC).

β_0 is the intercept.

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

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 domestic 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

Table 14 summarizes the regression results. Since all variables are expressed as natural logs, the regression coefficients can be interpreted directly as elasticities of demand. Since differences in electric prices among states are longstanding, 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-Square statistic indicates that altogether 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.

Table 14

Summary annual commercial electricity use per customer

Regression statistics									
Multiple-R	0.912267316								
R-Square	0.832231656								
Adjusted R-Square	0.817643104								
Standard error	0.132847813								
Observations	51								
ANOVA									
	df	SS	MS	F	Significance F				
Regression	4	4.027178377	1.006794594	57.04690059	2.96769E-17				
Residual	46	0.81183291	0.017648542						
Total	50	4.839011287							
	Coefficients	Standard error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%	
Intercept	-6.362496117	0.786230961	-8.092400875	2.16205E-10	-7.945096959	-4.779895276	-7.945096959	-4.779895276	
LN (five-year price)	-0.501549627	0.076892586	-6.522730677	4.74891E-08	-0.656326374	-0.34677288	-0.656326374	-0.34677288	
LN (state GDP per commercial customer)	0.743840483	0.052266843	14.23159376	1.81969E-18	0.638632784	0.849048183	0.638632784	0.849048183	
LN average temperature	0.463083141	0.108195294	4.280067319	9.37886E-05	0.24529731	0.680868972	0.24529731	0.680868972	
LN (energy efficiency investment 10-year per residential and commercial customer)	-0.037255632	0.013877971	-2.684515727	0.010064634	-0.065190539	-0.009320725	-0.065190539	-0.009320725	

Source: IHS Markit

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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 DC).

β_0 is the intercept.

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

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

Table 15 summarizes the regression results. Since all variables are expressed as natural logs, the regression coefficients can be interpreted directly as elasticities of demand. Since differences in electric prices among states are longstanding, 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-Square statistic indicates that altogether 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.

Table 15

Summary annual industrial electricity use per customer

Regression statistics

Multiple-R	0.79235173
R-Square	0.627821264
Adjusted R-Square	0.612313817
Standard error	0.745614116
Observations	51

ANOVA

	df	SS	MS	F	Significance F
Regression	2	45.01465697	22.50732848	40.48514566	4.98927E-11
Residual	48	26.68513968	0.55594041		
Total	50	71.69979665			

	Coefficients	Standard error	t Stat	P-value	Lower 95%	Upper 95%
Intercept	0.091209421	2.820686164	0.032335898	0.974338269	-5.580160221	5.762579062
LN (five-year price)	-1.496288156	0.317495819	-4.712780656	2.1282E-05	-2.134656286	-0.857920026
LN GDP	0.738646324	0.103125489	7.162597056	4.14372E-09	0.531298632	0.945994017

Source: IHS Markit

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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 a -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 B: Cost-effective power supply and efficient electricity system operations

Some of the current discord between public policies and market operation reflects the encroachment of the idea that “base-load” generation—an efficient alignment of generating technologies to the steady segment of consumer demand is now an obsolete concept. However, long-standing engineering and economic principles underlying the determination of a cost-effective power supply portfolio that cost-effectively aligns base-load, cycling, and peaking technologies to the steady, fluctuating, and infrequent load segments of consumer demand by making efficient trade-offs between higher fixed costs and lower variable operating costs associated with the current state of power supply technologies.

Engineering and economic factors that determine cost-effective grid-based power supply

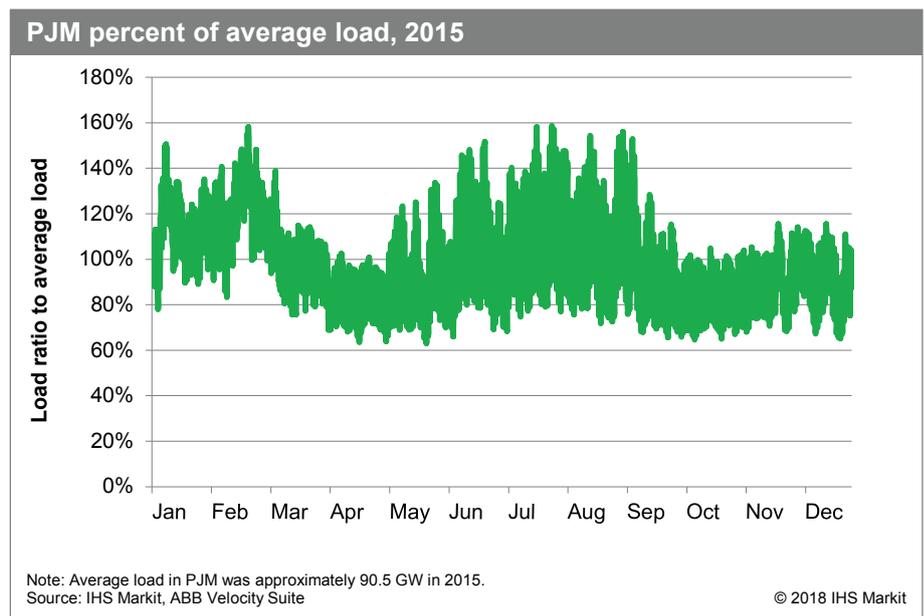
Efficient electricity production requires making economic trade-offs to align cost-effective generating resources with the recurring annual pattern of aggregate consumer grid-based electricity demand.

Consumer demands for grid-based electricity throughout the year reveal a preference to use different amounts of grid-based electricity at different points in time. These consumer demand patterns through time reflect numerous factors that make power demand deviate from average levels such as temperature changes, work schedules, holidays, and hours of sunlight. Since many of these factors vary in predictable ways throughout the year, the hourly consumer electricity use results in a recurring hourly annual consumer load pattern. The recurring daily, weekly, and seasonal load patterns from one year to the next are observed by expressing the annual load pattern as the ratio to the annual average hourly load level.

Figure 12 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 PJM, the seasonal movements in aggregate demand to levels well above average reflect the influence of electric end uses sensitive to the recurring weather conditions in the winter and summer. By contrast, the stable, lower-than average electricity usage levels that define the base of consumer demand throughout the year reflect the weather-insensitive consumer uses of electricity.

In PJM, 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. The PJM net load profile (hourly aggregate consumer load minus the generation from nondispatchable resources, such as wind and solar outputs) also shows that the base net load accounts for majority of the electric output supplied by resources dispatched by PJM to generate electricity.

Figure 12



Expressing power system hourly aggregate consumer demands as ratios to the average load and ordering these load metrics from highest to lowest ratio produces a power system aggregate consumer annual load duration curve. Whereas an aggregate consumer annual demand curve segments power system demand by price level, a load duration curve segments annual aggregate consumer demand by time duration. The load duration curve indicates the percentage of hours across the year associated with different aggregate load levels. Figure 13 shows the PJM load duration curve expressed as a ratio to average load in 2015.

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

Consumer preferences for a high degree of grid-based electric supply reliability is the primary determinant of the overall size of the power system supply portfolio where the net dependable capacity (the expected power plant capacity after adjustments for the risk of disruptions at time of peak) is sufficient to deliver the desired level of reliability.

Reliable and resilient power system operation requires resilient balancing of 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 in time, providing reliable electric service requires operating with some of these resources in reserve. Therefore, a robust reserve uses diversity of capacity to mitigate potential deviations from normal operating conditions affecting the availability of a given generating technology or fuel source. For example, an operating reserve made up entirely of natural gas-fired resources supplied from a common pipeline could provide power supply reliability under normal pipeline operating conditions. However, the reserve would not be resilient to a pipeline disruption. By contrast, a diverse operating reserve 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.

Alternative generating technologies bring different cost and performance characteristics to a power supply portfolio. As Figure 14 shows, each technology brings different performance characteristics to an electric supply portfolio, including

- **Flexibility/dispatch**—the capability to vary electric output to follow net load through time.
- **Reliable capacity**—the capability to provide capacity when needed.

Figure 13

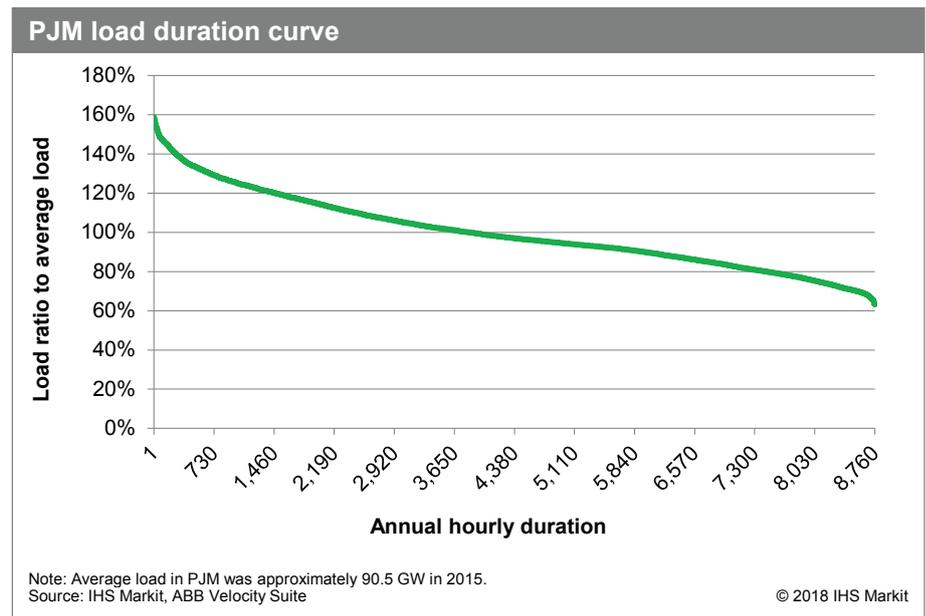
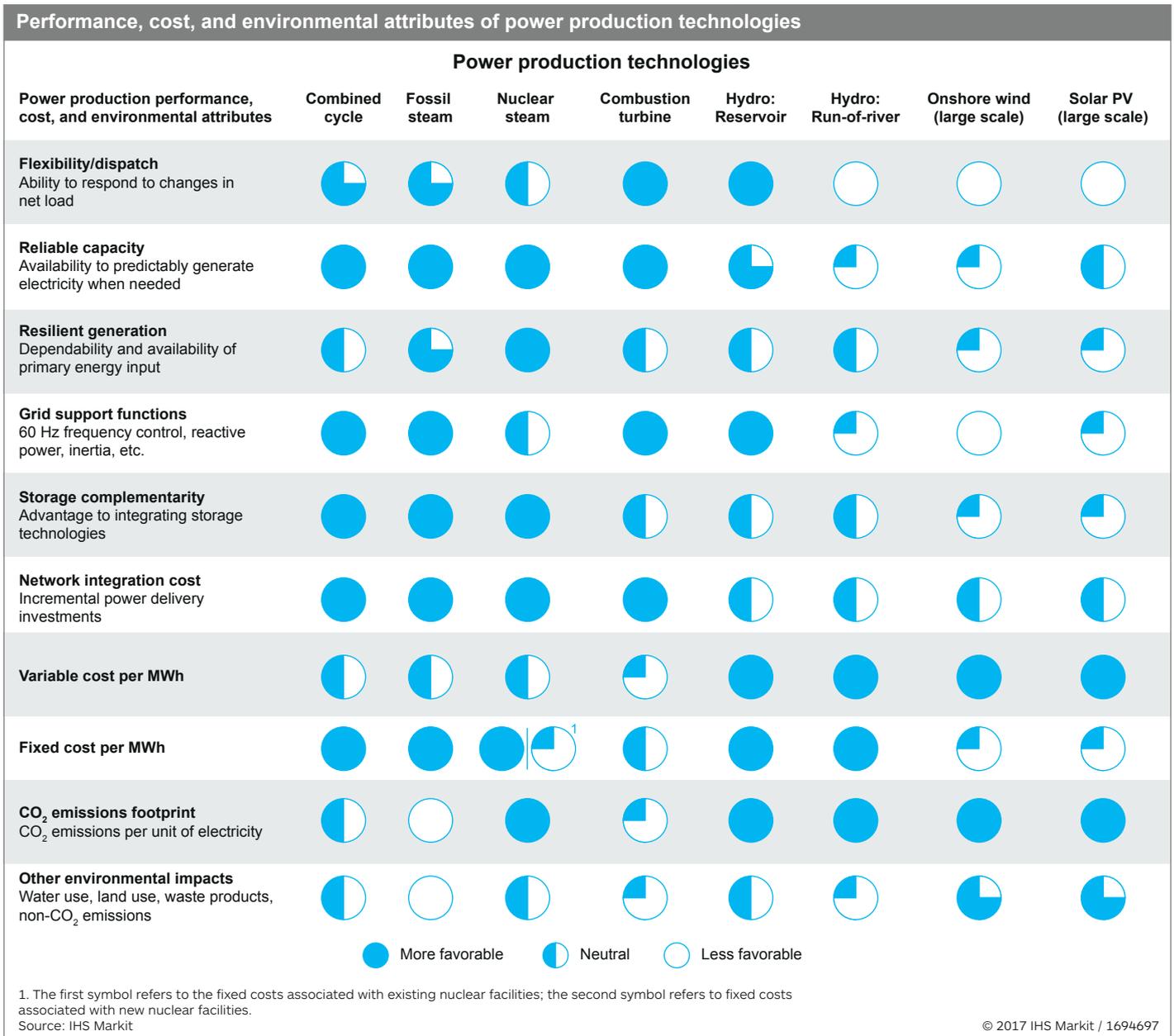


Figure 14



- **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 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.
- **CO₂ emission footprint**—the level of CO₂ emissions per unit of electric energy output.
- **Other environmental impacts**—the per-unit cost of non-GHG environmental impacts associated with electric generation.

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 the recurring annual real-time pattern of power system aggregate consumer demand. Although a simple levelized cost of electricity metric can indicate that a single generating technology provides the lowest levelized cost electric energy 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 DOE’s 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.² Therefore, if solar PV provided the lowest levelized cost of electric output compared with other electric supply technologies, a 100% solar PV power supply portfolio would neither be capable of meeting peak demands, nor 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 that were in the path of the 21 August 2017 solar eclipse. The US power system resiliency to this event illustrates the value of the current diversified power supply portfolio.

The cost-effective resilient 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. 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 reliably balance with the varying real-time aggregate demand levels with limited economic inventory options.³

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

2. Lori Bird, Carolyn Davidson, Joyce McLaren, and John Miller, *Impact of Rate Design Alternatives on Residential Solar Customer Bills: Increased Fixed Charges, Minimum Bills and Demand-Based Rates*, National Renewable Energy Laboratory, US DOE, September 2015, <http://www.nrel.gov/docs/fy15osti/64850.pdf>, retrieved 27 March 2018.

3. Oliver E. Williamson, “Peak-Load Pricing and Optimal Capacity under Indivisibility Constraints” *American Economic Review* 56, no. 4 (September 1966): pp 810–827.

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 into electric energy.

An example employing two consumer demand segments and four alternative generating technologies illustrates that a cost-effective electric supply portfolio involves an integration of different generating resources. In this example, the consumer demand segments are the variable load and the base-load segments and the generating technologies are a simple-cycle combustion turbine, a combined-cycle generating technology, and a cogeneration technology.

Table 16 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.

As the cost and performance profiles indicate, the combined-cycle technology involves 58% higher up-front capital costs to deliver 35% greater efficiency in transforming natural gas into electricity compared with the combustion turbine. Figure 15 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 combustion turbine and the combined-cycle 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 (levelized cost of energy) decline as utilization rates increase. In this example, the benefits of greater production efficiency do not outweigh the costs until expected utilization rates approach 30%.

In this example, the combustion turbine 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 combustion turbine 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 combustion turbine with the peak demand segment of aggregate consumer demand identifies this technology as the least-cost “peaking technology.”

Figure 15 also shows that the trade-off between the up-front costs and the greater production efficiency makes the combined-cycle generating technology more cost effective than the combustion turbine to supply variable customer loads that are present more than about 30% of the year. Consequently, the combined-cycle generation technology cost-effectively aligns with this segment of aggregate consumer demand.

Table 16

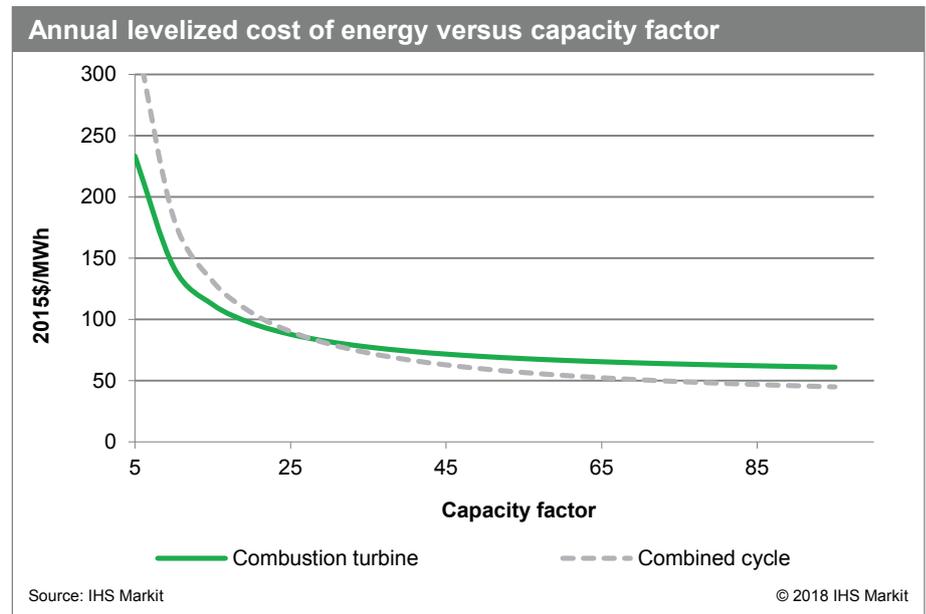
Electric generating technology cost and performance profiles								
Technology	Size (MW)	Lifetime/ MACRS (years)	Overnight costs (2015\$/ kW)	Lead time (years/ CFUDC)	Contin- gency factor	Variable nonfuel O&M (2015\$/ MWh)	Fixed O&M (2015\$/ MWh)	Heat rate (Btu/kWh)
Natural gas-fired combustion turbine	237	30/20	\$632	2/1.14	1.05	\$10.5	\$6.7	10,878
Natural gas-fired combined cycle	429	30/20	\$1,000	3/1.2	1.08	\$2.0	\$9.8	7,010

Source: IHS Markit, EIA

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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 combustion turbine or combined-cycle 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.

Figure 15



The simple example of minimizing the cost of electricity supply across two demand segments and three technologies provides the basis to understand the cost-effective integration of intermittent generating technologies or electric energy storage technologies. The cost-effective amount of intermittent renewable generation follows from the cost-effective match of aggregate consumer demand segments to dispatchable generating technologies. The mix of dispatchable generating technologies creates varied SRMCs 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 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 upon to offset net dependable capacity requirements.

Entry of intermittent resources into a power system supply portfolio creates a net impact on 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 systems 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 in time, charging and discharging a storage technology can lower the overall power system cost. Since 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 impact is the lower overall power system cost resulting from charging at relatively low power system SRMC intervals and discharging at relatively higher power system SRMC intervals. The second impact is the lower cost of net dependable capacity due to the availability of the discharge capacity during periods of capacity reserve scarcity. The third impact 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 a higher amount of cost-effective storage in the supply portfolio, and as the amount of storage increases, the net load factor increases along with the level of 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.

The simple examples illustrating the underlying trade-offs that determine the composition of a reliable, resilient, and efficient electric supply portfolio provide 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 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.** Greater operational flexibility is not always cost effective because most 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 that internalize an appropriate charge for environmental impacts rather than employ discordant command and control approaches can alter, but not distort, the cost-effective alignment of aggregate consumer demand segments with available power generation technologies and fuels.

Principled government interventions harmonized with markets to produce effective competition and efficient market outcomes

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. To supply this segment, competitive forces drive investment toward generating technologies with flexible dispatch capabilities and the lowest average total costs at low annual utilization rates. As a result, during the infrequent, highest hourly market demand periods, competitive forces drive market-clearing energy price to reflect the SRMCs of rival peaking resources. However, an inherent flaw exists in electricity markets that prevent the SRMCs of the peaker units from rising to equal the LRMCs when the market is in long-run balance, including the desired reserve margin associated with reliability goals. On the regulation side, principled government interventions to address this “missing money” problem involved the evolution of capacity markets or operating reserve demand curves. These regulatory interventions offset this inherent market flaw by generating capacity market prices or operating reserve demand curve payments that produce an efficient market outcome in which a market-clearing capacity price or operating reserve demand payment closes the gap between SRMCs and LRMCs 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 of a supply interruption exceeds the cost of incorporating backup fuel capability, then the marketplace will generate profitable investments in fuel supply resiliency for these 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 only involve investments in combustion turbines. When a sufficient number of rival suppliers compete to serve the segments of 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 higher than peakers that

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 SRMCs are what economists call "inframarginal rents"). Again, price signals provide incentives for resiliency. For example, a combined-cycle 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 along with 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 and 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 wholesale price levels correspond to relatively low demand levels, and, conversely, relatively high wholesale price levels correspond to relatively high demand levels, the market impact of economic storage entry produces a higher net load factor and triggers adjustments in the dispatchable generation portfolio that produces 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.

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 drives investment to a mix of storage and generating technologies with different costs, efficiencies, and operating characteristics that altogether produce the lowest possible total average cost to meet the peak demand and the annual aggregate net load pattern.⁴

The bottom line is that the expected outcome in an undistorted and efficient electricity marketplace provides the benchmark to evaluate current PJM market outcomes and the impact of policy interventions.

4. Oliver E. Williamson, "Peak-Load Pricing and Optimal Capacity under Indivisibility Constraints" *American Economic Review* 56, no. 4 (September 1966): pp 810–827.

Appendix C: Causes, consequences, and dynamics of PJM market distortions

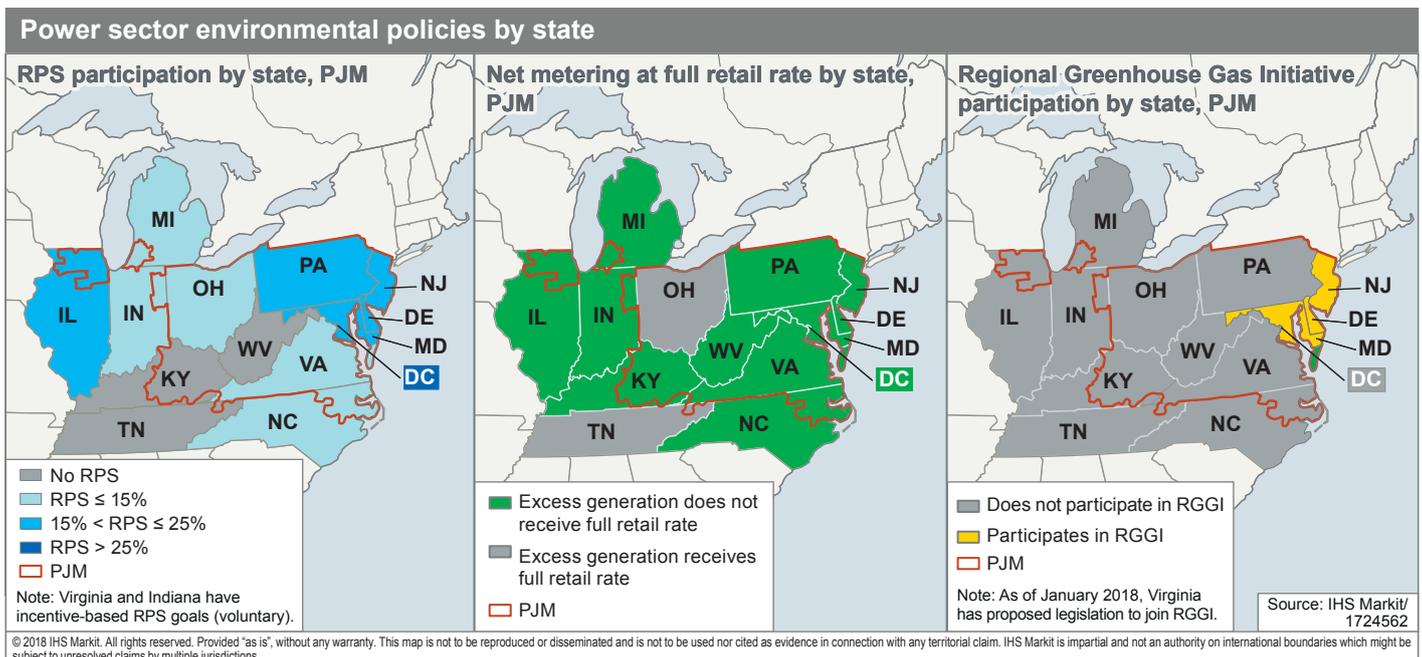
Current discord between public policies and market operations creates PJM wholesale electricity market distortions

Public policy formulation reflects the political process of negotiation and compromise, and the policy outcomes at the federal, state, and independent system operator (ISO) level do not always harmonize with efficient wholesale electricity market operations. Five misalignments are currently distorting PJM wholesale market operations:

- Subsidies based on renewable output levels, including federal Production Tax Credits (PTCs), shift costs away from the marginal cost-based supply bids for some non-CO₂-emitting generators and not others; these subsidies do not treat similarly situated rival generators equally.
- A patchwork of mandates for intermittent wind and solar technology generation shares, as shown in Figure 16 (left), override market-determined renewable generation investments.
- Subsidies including federal Investment Tax Credits and solar PV net metering at retail rather than wholesale prices, as shown in Figure 16 (middle), alter investment decisions by favoring some non-CO₂-generating technologies and not others.
- A variety of CO₂ emission charges, as shown in Figure 16 (right), apply to some but not all rival generators in the marketplace.
- Energy market-clearing prices are reset to reflect the impact of security constraints on grid-based generator economic dispatch below the marginal generating costs of resources providing power supply.

A consensus regarding the causes, consequences, and dynamics of current PJM market distortions does not currently exist. Nevertheless, a broader recognition of the problem of market distortions is emerging. FERC member Neil Chatterjee noted that, “As states take on policy initiatives to influence the local generation

Figure 16



mix, it's having an impact on our markets.”⁵ The DOE Staff Report to the Secretary on Electricity Markets and Reliability noted the work of economist Severin Borenstein who concluded, “In California, New York and many other states, wind and solar are pushing down wholesale prices and making continued operation of some nuclear and fossil fuel generation unprofitable.” The DOE report also noted that the DOE Quadrennial Energy Review found “... price suppression from wind and solar is putting financial pressure on base-load power plants.”⁶ The PJM ISO concluded, “...subsidies can suppress wholesale electricity markets and threaten these markets’ basic design mission.”⁷

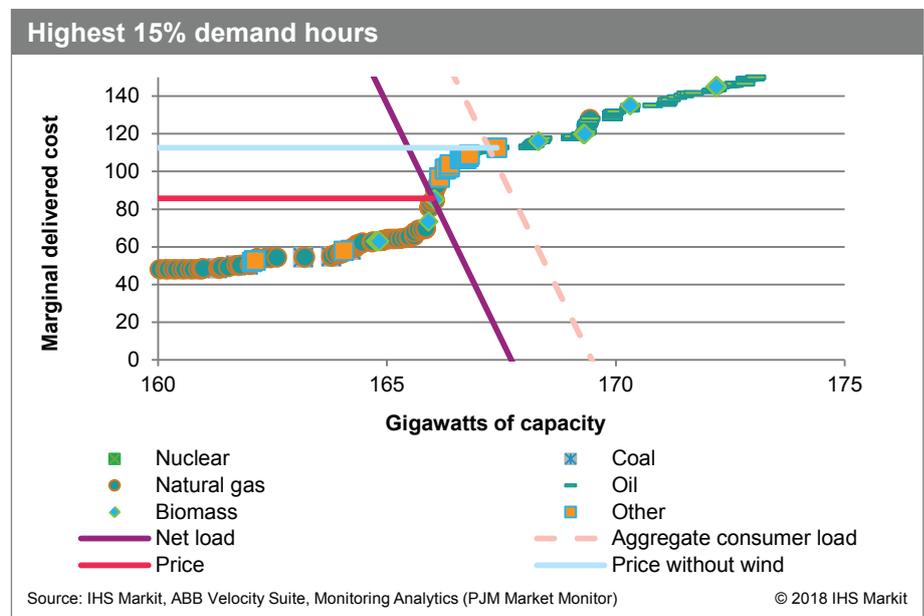
The current misalignment of public policies and PJM market operations causes predictable short- and long-run market distortions.

Suppression of wholesale electric energy market prices

Policy initiatives that drive wind and solar additions beyond their market-determined level impact the interaction of market demand and supply. Analyses of the impacts on market-clearing prices can employ the conventional framework of intersecting market demand and supply curves. Policy-driven wind and solar generation can be represented as either a rightward shift in the supply curve whenever the wind blows or the sun shines due to the addition of zero-SRMC resources or represented as a leftward shift in the demand curve whenever the wind blows or the sun shines due to a reduction in the net load (consumer demand less intermittent renewable power generation).

Figures 17–19 graphically illustrate recent PJM wholesale price suppression from policy-driven intermittent renewable generation. The figures show interactions of PJM supply and demand curves during three different demand intervals in 2015. PJM electricity market demand and supply curve interactions show 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 17



The market demand and supply interactions show 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

5. S&P Global Market Intelligence Power and Gas M&A Symposium, 1 February 2018, New York as reported in “Updated guidance could help FERC balance state policy with market integrity,” SNL, 2 February 2018, <https://platform.mi.spglobal.com/InteractiveX/article.aspx?CDID=A-43415492-10550&KPLT=4>, retrieved 7 February 2018.

6. US DOE, *Staff Report to the Secretary on Electricity Markets and Reliability*, August 2017, pp. 110–112.

7. PJM, *Context for PJM Market Design Proposals Responding to State Public Policy Initiatives*, June 2017, <http://www.pjm.com/~media/library/reports-notice/special-reports/20170612-context-for-pjm-market-design-proposals-responding-to-state-public-policy-initiatives.ashx>, retrieved 25 February 2018.

suppressed prices by about 4% during the 15% of hours around average net load, and by about 9% during the hours associated with minimum net load levels.

Whereas the maximum, average, and minimum demand and supply interactions shown in Figures 17–19 show typical demand and supply conditions, atypical conditions arise when aggregate consumer loads are less than the sum of output from zero-marginal cost generating resources and minimum output from resources needed for power system security of supply. Under these “overgeneration” conditions, the PTC volume-based subsidy creates a short-run marginal generating opportunity cost of negative \$23/MWh (2016) for subsidized wind generation. As a result, a rational wind generator bids a negative price as high as -\$23/MWh into the wholesale marketplace to supply electric energy and avoid losing the PTC. Consequently, the impact in the interactions of market demand and supply curves is enough to suppress market-clearing prices to negative levels, as shown in Figure 20. 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 PJM market price formation for more than a decade to come. As Figure 20 shows, overgeneration conditions caused 19 hours of negative PJM market-clearing energy prices in 2017.

Figure 18

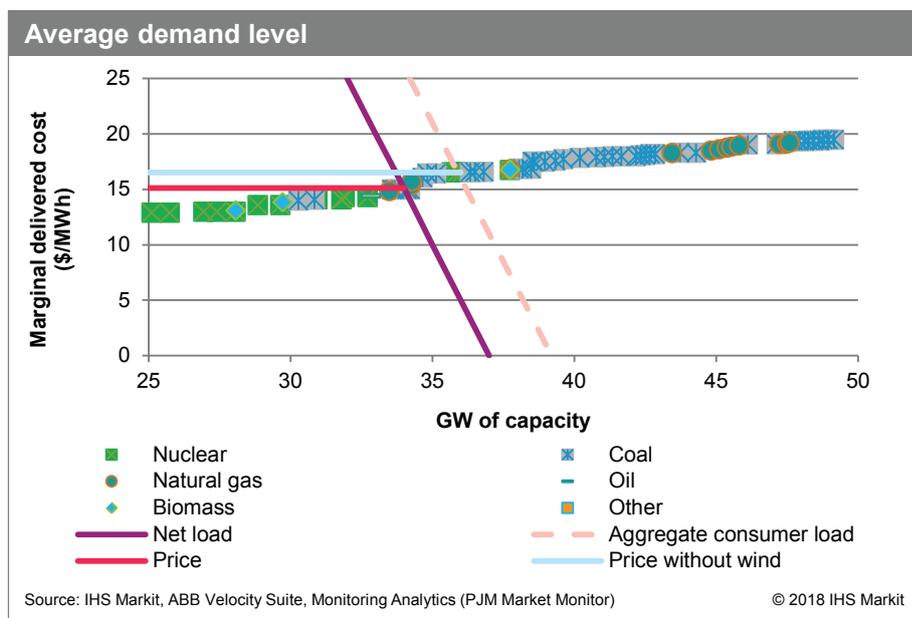
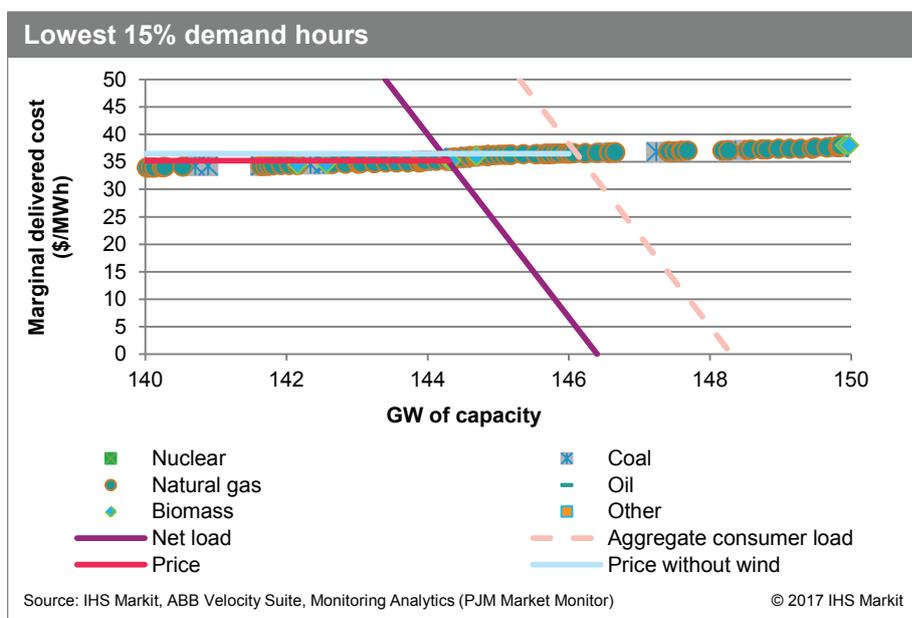


Figure 19



The bottom line is that command and control policy interventions that overwrite the market-based renewable generation shares cause suppression of market-clearing energy prices. Since suppression of prices below unfettered efficient market levels is not sustainable in the long run, the suppression of energy market prices triggers market adjustment in both the energy and capacity marketplaces.

Prolonged short-run capacity market imbalances

Mandates of renewable resource generation shares push renewable capacity development beyond the level expected in an unfettered marketplace. In an unfettered marketplace, rational investors are not expected to make unprofitable investments. In PJM, most renewable resource development involves wind technologies and the 2015 PJM market monitor report indicated that PJM wind entry costs were typically uneconomic without subsidies.⁸ The shortfall is significant because selling wind output in PJM during 2015 at market-clearing prices yielded an average wind output weighted wholesale price of \$34.40/MWh. This realized wholesale electricity price for wind output was well below the EIA estimates of the range for unsubsidized levelized cost for wind entry in the United States of between \$41/MWh (2015) and \$71/MWh (2015).

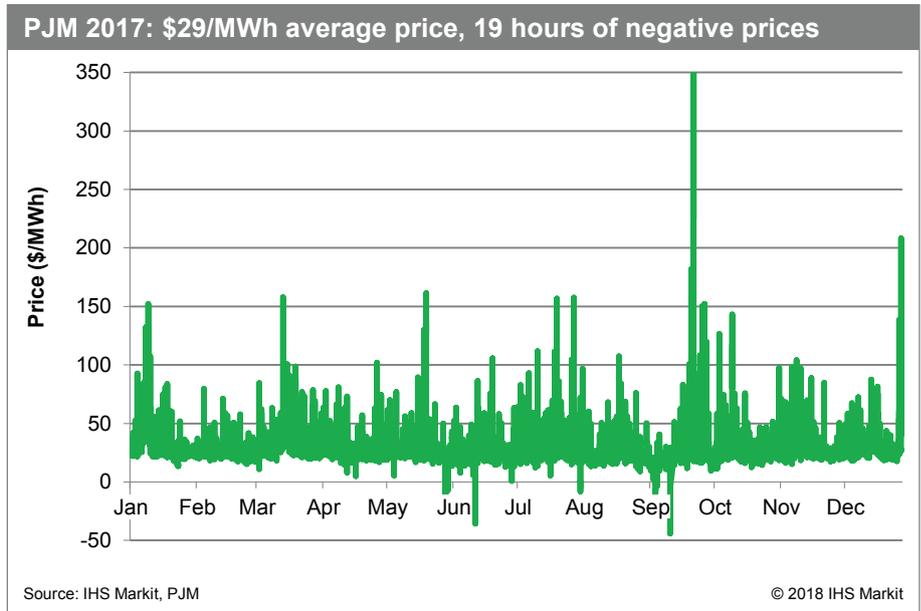
PJM wind market cash flow shortfalls are persistent. The 2016 PJM market monitor report indicates that PJM wind entry costs are at the high end of the EIA cost range and that capacity and energy prices in 2016 would provide net revenues that covered less than half of the annual costs of new entry for wind generating technologies.⁹

Renewable generation mandates distort PJM capacity as well as energy markets. The ratcheting up of state mandates for renewable supply adds net dependable capacity that would not otherwise enter the market. As a result, policy-driven outside-of-the-market mechanisms added firm solar and wind capacity into the supply side of the PJM capacity market beyond the level expected in the unfettered marketplace.

Policy-driven net dependable renewable capacity additions have altered the PJM demand and supply interactions that determine market-clearing capacity prices by delaying the point in time when market price signals need to increase to the level necessary to incentivize new capacity development compared with the point in time expected in an undistorted market outcome. These policy-driven capacity additions have prolonged the excess of PJM capacity supply relative to demand and prolonged PJM capacity price suppression.

A prolonged PJM capacity market imbalance caused chronic market cash flow shortfalls for new PJM power supply entrants. The PJM State of the Market Report for 2016 notes that a typical new natural gas-fired combustion turbine that began operation in PJM one decade ago would not have been able to cover their total costs from energy and capacity market revenues through December 2016.¹⁰

Figure 20



8. Monitoring Analytics: *State of the Market Report for PJM* (2015), Volume II, Section 7 (“Net Revenue”), 2016, http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2015/2015-som-pjm-volume2-sec7.pdf, retrieved 27 March 2018.

9. *Ibid.*, p. 279.

10. Monitoring Analytics, LLC, *State of the Market Report for PJM* (2016), 9 March 2017, p. 279, http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2016/2016-som-pjm-volume2.pdf, retrieved 27 March 2018.

Higher long-run capacity prices

Suppressing prices below an efficient market level is not sustainable. Ongoing energy and capacity price suppression accelerates the retirement of existing generating resources and discourages investments in competitive new supply development. Consequently, capacity market imbalances will end when load growth and capacity retirements eventually outpace policy-driven net dependable capacity additions.

Since nuclear capacity currently accounts for 18% of PJM installed capacity, the potential acceleration of PJM nuclear power plant closures has the potential to significantly affect PJM capacity demand and supply balances and create upward pressure on long-run market-clearing capacity prices.

When capacity demand and supply are in balance, reliability targets incorporated into the PJM wholesale market design cause capacity market cash flows to augment energy market cash flows to cover the cost of new entry (CONE), equal to the annual levelized fixed costs of the least-cost capacity option, typically reflecting the cost of developing a simple-cycle combustion turbine peaking generation technology.

The PJM capacity market design incorporates a capacity demand curve that produces capacity price levels and associated market cash flows that are sufficient to cover the annual net cost of new entry (net-CONE) when demand and supply achieve a long-run balance. The net CONE equals CONE minus the contribution toward fixed costs from the energy market when capacity demand and supply are in balance.

The PJM capacity and energy market linkage means that the capacity price can clear at net CONE even if market distortions suppress energy market cash flow contributions toward fixed costs. In the extreme, the capacity market can clear at CONE if energy market price suppression is enough to reduce the expected inframarginal rents—the difference between the energy market-clearing price and the generator's own SRMC—to zero.

When PJM capacity market demand and supply are in balance along with a distorted PJM energy market outcome, the linkage between the capacity and energy market increases the expected long-run capacity price compared with the level expected in a capacity market operating alongside an undistorted energy marketplace.

The ability of the PJM market to provide timely price signals for new capacity additions in the presence of energy market distortions appears to be present. Currently, PJM capacity markets clear within 20 load deliverability area zones and the energy market trades occur across hundreds of nodes. The degree of energy market price suppression differs by location along with capacity demand and supply balances. The PJM State of the Market Report finds that a typical new natural gas-fired combustion turbine electric generating technology would have received sufficient combined capacity and energy net revenues from recent market-clearing prices to cover its annual levelized costs in 13 of the 20 PJM transmission zones.¹¹

The bottom line is that when energy market distortions suppress energy market-clearing prices, then in the long run, market-clearing capacity prices will increase to cover net CONE and offset the impact of energy market cash flow suppression on the profitability of investing in peaking technology development. As a result, the capacity and energy market linkage creates higher long-run capacity prices as a backstop to prevent energy market cash flow suppression from leading to capacity shortages.

Underinvestment in electric production efficiency

Market distortions decrease energy market cash flows relative to capacity market cash flows and, as a result, reduce the level of investment in the efficiency of transforming primary energy into electricity.

11. Monitoring Analytics, LLC, *State of the Market Report for PJM* (2016), 9 March 2017, p. 279, http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2016/2016-som-pjm-volume2.pdf, retrieved 27 March 2018.

Efficient power supply requires operating different power plants at different utilization rates to satisfy varying levels of aggregate consumer demand through time. In an efficient marketplace, the varied generator market cash flows are the sum of capacity and energy market cash flows and the proportion of cash flows from the energy market increases as the power plant utilization rate increases. The implication of this relationship is that energy market inframarginal rents cover the higher up-front costs of generation technologies that deliver greater efficiency in transforming primary energy into electricity compared with peaking technologies. Therefore, the mix of energy and capacity market cash flows associated with varied expected utilization rates determine the cost-effective level of investment in electric generation production efficiency for each resource in the overall power supply portfolio.

Since market distortions increase capacity prices relative to energy prices, the return to investment in greater productive efficiency in the energy market declines relative to the return of investing in capacity. The implication is that PJM energy market distortions disproportionately suppress the cash flows of non-CO₂-emitting generating resources that cost-effectively align output to the nonpeaking segments of consumer electricity demand.

When energy market distortions exist, the linkage between PJM capacity and energy markets does not provide a backstop for recovering the higher up-front costs of nonpeaking generating technologies that are more efficient at transforming primary energy into electricity compared with the up-front cost and generating efficiency of the least-cost peaking technology. As a result, the leading edge of uneconomic retirements from energy market distortions are likely to involve nuclear base-load generating resources in the generating portfolio with their relatively higher up-front investments in the efficiency of transforming primary energy into electricity and the associated relatively lower incremental generating costs.

As the market adjustments play out, the power supply portfolio shaped by distorted price signals is increasingly composed of too many relatively inefficient peaking technologies and too few relatively efficient non-CO₂-emitting base-load resources compared with the supply portfolio expected from an undistorted PJM energy market operating alongside an undistorted PJM capacity market. In the long run, increasing generation shares of peaking technologies create upward pressure on energy prices that counter some of the price suppression of mandated and subsidized renewable resources. As a result, the long-run impact on cycling technologies is the net effect of market distortions and long-run market adjustments.

The bottom line is that the consumer impact of underinvestment in electric energy productive efficiency causes a long-run increase in the overall average cost of electric production as the marginal costs of resources setting prices in the off-peak period increasingly resemble the marginal costs of resources setting prices in the on-peak period.

Underinvestment in power plant operating resilience

Competitive generators can make money only by being able to operate when the market-clearing wholesale energy price exceeds their short-run marginal generating cost. Therefore, competitive generators have an economic incentive to be available in the marketplace. The difference between expected wholesale energy price levels and SRMCs determine the benefits for an electric supplier of being available for economic dispatch.

Power plants are complex technologies that present a variety of investment capable of improving power plant availability. Since these various options involve different costs, a rational, profit-maximizing competitive electric generator will pursue the available investments to increase availability up to the point where the marginal cost of the investment equals the marginal benefit. The implication is that suppression of energy market cash flows due to market distortions leads to underinvestment in power plant availability compared with the cost-effective investment in power plant availability expected in an undistorted market outcome.

Less resilient PJM production costs

Market distortions produce a less efficient mix of fuels and technologies in the power supply portfolio. As a result, some of the inherent resilience to cost risk factors is lost and the variability of production costs increases. The impact on consumers is more varied monthly power bills compared with the monthly power bill variability expected from generation portfolio shaped by an undistorted efficient market outcome.

The bottom line is that cost-effective nuclear generation in the PJM supply portfolio provides a zero-cost source of electric production cost resilience, and other mechanisms, such as financial hedging instruments, would need to be employed to restore the production cost resilience lost due to uneconomic nuclear power plant closures. Since these other production cost risk mitigation options are more expensive, a balancing of the costs and benefits of production cost risk management results in a lower level of resilience.

Uncompensated integration and security of supply costs

PJM coordinates the interdependent operation of generating resources throughout the grid. Operational interdependency of generating resources and the grid reflect the impacts of transmission constraints and security of supply constraints. As a result, PJM market operations do not simply clear the market with a single electric energy price across all hours that reflects the intersection of the aggregate consumer demand curve with the aggregate bid-based PJM supply curve. Instead, ensuring the security of power system operations requires adjustment of this simple unconstrained market result to the redispatch of power plants to manage transmission line loadings, regulate voltage and frequency, and position the power system operations to be resilient to the most significant potential deviations from expected operating conditions. Some, but not all, of the costs associated with the adjustments involved in the security-constrained redispatch of PJM electric supply to demand are reflected in the market-clear energy price. The partial coverage of these incremental costs is a market flaw because some by generators providing the resilience attributes required for secure grid operation are not fully compensated.

The impact of wind and solar output on the sequential hourly net load pattern causes generators to start and stop output and ramp output up and down more frequently and, thus, incur less production efficiency and higher O&M costs. In addition, increasing renewables decreases the power system net load factor and increases the cost of security-constrained redispatch.

The bottom line is that the addition of intermittent renewable generation beyond the market-determined level decreases generating cash flows on the cost side by increasing the operating costs of flexible PJM generating resources and decreasing generating cash flows on the revenue side by increasing redispatch marginal generating costs and expanding the shortfall to repriced energy market price levels.

Appendix D: Hedging natural gas-fired electric generation costs

Consumers in PJM will be exposed to greater power price variability owing to the increased reliance on natural gas fuel supply under the less efficient diverse fuel supply portfolio case. The implicit value to PJM consumers of greater power price stability from the PJM base case portfolio can be comparable to the cost of using financial instruments as a substitute for a more efficient power supply portfolio to hedge the higher production cost variability in the less efficient diversity scenario over 2013–16.

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

Backcasting the purchase of natural gas call options on a monthly basis at a rolling strike price set equal to the current price of natural gas in PJM reduces the variability (standard deviation) of the variable cost of electricity production in PJM by 18% from 2013 to 2016. The average annual cost of purchasing the natural gas call options based on this strategy is \$251 million. Therefore, the average cost to reduce production cost variability by 1% is \$13.5 million. Because the production cost variability in PJM is 53% higher in the nuclear scenario, the cost to use natural gas call options to achieve the same level of production cost variability as in the PJM base case is \$714 million.

The formula used to calculate the theoretical price of an option is shown below and is based on a variant of the Black-Scholes option pricing formula:¹²

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

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

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

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

Where:

C_T is the value of the call option contract.

S_T is the strike price.

X is the natural gas spot price.

12. James Read and Art Altman, “Energy Derivatives and Price Risk Management,” in *Pricing in Competitive Electricity Markets*, eds. Ahmad Faruqui and Kelly Eakin (Springer US, 2000). Retrieved from <http://www.springer.com/us/book/9780792378396> on 27 March 2018.

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

r is the risk-free rate of return.

σ is the volatility of the spot price of natural gas.

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

IHS Markit Customer Care

CustomerCare@ihsmarkit.com

Americas: +1 800 IHS CARE (+1 800 447 2273)

Europe, Middle East, and Africa: +44 (0) 1344 328 300

Asia and the Pacific Rim: +604 291 3600

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