Estimating the Value of Energy Efficiency to Reduce Wholesale Energy Price Volatility

Brendon Baatz, James Barrett, and Brian Stickles

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529 14th Street NW, Suite 600, Washington, DC 20045

Phone: (202) 507-4000 • Twitter: @ACEEEDC

Facebook.com/myACEEE • aceee.org

Contents

About the Authors

Brendon Baatz until recently led ACEEE's utility program, with a focus on state energy efficiency policy, utility regulation, energy markets, utility resource planning, and utility-sector efficiency programs. Prior to joining ACEEE, he worked for the Federal Energy Regulatory Commission, Maryland Public Service Commission, and Indiana Office of Utility Consumer Counselor. Brendon holds a master of public affairs in policy analysis from Indiana University and a bachelor of science in political science from Arizona State University. Brendon now works at Gabel Associates.

James Barrett is a visiting fellow at ACEEE. He concentrates on the nexus of climate change, energy efficiency, and economics and has written extensively on the role of efficiency in achieving environmental and economic goals. Prior to joining ACEEE, Jim was executive director of Redefining Progress, a public policy think tank dedicated to promoting a healthy environment, a strong economy, and social justice. Before that he was an economist at the Economic Policy Institute, a senior economist on the Democratic staff of the Joint Economic Committee, and a staff economist at the Institute for Biological Energy Alternatives. Jim earned his bachelor of arts in economics from Bucknell University and his master of arts and PhD in economics from the University of Connecticut.

Brian Stickles is a senior research analyst with the Economics and Finance Policy team, focusing on best practices for financing energy efficiency improvements. He holds a master of arts in economics from New York University and a bachelor of science in economics and business from Skidmore College.

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Executive Summary

Wholesale energy prices have historically been volatile for several reasons, including weather and fuel price fluctuations, and this volatility can impose significant costs on electricity buyers and sellers. It does not usually directly affect retail electric customers but does indirectly increase prices over time. Short-term fluctuations in wholesale energy prices increase the risk premium paid by market participants. This increases the long-term cost of electricity as market participants attempt to price future volatility into both long- and short-term contracts.

Utilities and other market participants must manage price volatility using a variety of strategies to hedge against unanticipated price swings. Common strategies include both physical hedges (such as long-term fixed-price contracts) and financial hedges (such as futures contracts). These come at some cost and themselves bear some risk, specifically that prices will not be volatile, rendering the hedges and their costs unnecessary after the fact.

This report examines the degree to which electricity price volatility generates asymmetric upside risk (i.e., the degree to which upward unexpected price swings cost buyers more than unexpected downward swings save them). To the extent that upside risk is greater than downside risk, investments in electricity resources that have fixed prices will generate value associated with the reduction in this risk. Energy efficiency is one such resource.

Previous ACEEE research has shown that energy efficiency often is the least-cost resource available to utilities.[1] In addition, the use of efficiency to reduce demand has system-wide benefits. Often referred to as demand reduction induced price effects (DRIPE), these are the benefits of efficiency that result when reduced electricity demand results in lower clearing prices. The value of DRIPE is largely independent of volatility.[2]

As we discuss in this study, efficiency has a benefit above and beyond DRIPE: It provides utilities and retail electric providers an additional strategy to reduce exposure to price volatility. Efficiency can serve as a type of long-term supply contract that provides energy resources at a fixed price. Though efficiency investments will often cost less than alternative physical hedges, they also come with risks, including the possibility that they will not perform as expected and that the price of physical supply will fall below the cost of the efficiency resource. However, to the extent that energy efficiency can meet electricity demand without being subject to price volatility and the need to hedge against it, efficiency can provide value. Resource planning should consider this value of reduced risk when making long-term decisions on how to meet anticipated electricity demand.

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[1] M. Molina, *The Best Value for America's Energy Dollar: A National Review of the Cost of Utility Energy Efficiency Programs* (Washington DC: ACEEE, 2014), aceee.org/research-report/u1402.

[2] To the extent that load volume and price volatility are correlated, reducing demand reduces volatility and risk at any given price point. This effect is additive to and distinct from the overall risk reduction benefits we discuss here and represents a potential area of future study.

In order to put this value in context, we examine the potential value at risk (VAR) utilities face due to volatile wholesale electricity prices. VAR measures the price that market participants may be willing to pay to avoid risk of price fluctuations and serves as one way to demonstrate the potential cost savings from hedging price volatility with energy efficiency. It is important to note that VAR is not a direct estimate of the risk reduction value of energy efficiency, since there are some risks that utilities prefer to bear. Rather, VAR gives an indication of how much risk energy efficiency and other hedging strategies can alleviate and provides an upper bound of the value of risk reduction such strategies confer.

We use a previously established method to analyze two years of data from the PJM service territory to determine ex post the amount of risk exposure inherent in day-ahead power purchases.[3] One year of the data in our sample (May 2013–June 2014) includes the polar vortex weather event, and the other year covers the 12 months immediately following. Calculating the value at risk (VAR) using historical data, we found that day-ahead power purchases in the 2013–2014 time period carried a risk premium of more than 25%, while the less extreme year of 2014–2015 exhibited a VAR of almost 14%. Taking the second year as representative, this means that from an ex ante planning standpoint, a utility or other power purchaser should be willing to pay a premium of up to 14% to avoid purchasing power in the day-ahead market and facing the risk that prices may spike.

These results show that volatility can impose significant costs on energy markets and that these costs can vary widely from year to year depending on external factors such as the weather. A more granular analysis examining individual utility service territories, or even nodes, would allow the estimation of risk premiums in specific locations and during specific load periods and would also allow policymakers to target energy savings at the times and locations with the highest value of risk reduction.

Energy efficiency is often the least-cost option for meeting electricity demand, and it comes without the risk of price volatility inherent in investments in generation. To the extent that efficiency investments can successfully lower system-wide price risk, the value of that avoided risk should be part of cost–benefit evaluations in resource planning. Properly valued, the risk-reducing properties of energy efficiency investments would likely lead to an increase in their deployment relative to situations in which that value is not recognized.

[3] PJM is the largest regional transmission operator (RTO) in the United States. It coordinates delivery of electricity for 65 million people in 13 states and the District of Columbia.

Energy Efficiency Background

This report considers the potential value of energy efficiency investments (or other demand reductions) to lower or avoid the risk of volatility in wholesale electricity prices. This value is above and beyond efficiency's commonly known benefits, which include direct energy savings for individual consumers and system-wide reductions in electricity demand. Efficiency also has a number of nonenergy benefits:

- Decreased pollution resulting from reduced demand for fossil-based energy
- Job creation, as energy efficiency investments and the savings they generate support more jobs than an equivalent amount of energy production
- Increased comfort and improved health in buildings with energy-efficient equipment and practices (for example, see Russell et al. 2015; Barrett and Baatz 2017)

Avoided utility costs are another key benefit of energy efficiency. They depend primarily on efficiency's being less costly than energy production and delivery. While this is not always the case, there is a large body of evidence that energy efficiency is generally less expensive than producing and delivering energy supply, and investing in efficiency can offer energy consumers considerable savings in comparison with purchased electricity. In short, efficiency is among the lowest-cost resource options available to utilities for delivering energy services to their customers (Molina 2014; Billingsley et al. 2014).

Efficiency programs can also reduce demand, thereby lowering wholesale energy, capacity, and natural gas prices. This is called demand reduction induced price effect (DRIPE), or market price suppression. When viewed as a reduction in wholesale price, DRIPE effects are often a small fraction of a percent (Hornsby et al. 2015). However the value may be substantial when considered in aggregate dollar terms, as the price reduction results in reduced costs for all customers, and not just those participating in energy efficiency programs.

Several recent studies have quantified the economic or financial value of energy efficiency programs in reducing demand (see Chernick and Plunkett 2014; Kenneally and Stanfield 2014; Exeter 2014; Hornsby et al. 2013). Estimates of DRIPE vary and are dependent on several key assumptions and methodological approaches. One study estimated a percentage reduction in wholesale energy prices of 0.0095–0.0428% for every percentage reduction in load, with a high of 0.721% for Massachusetts in the summer peak period (Hornsby et al. 2015). Another study, completed in Illinois, showed that a 1% reduction in load in Illinois and much of the Midcontinent ISO territory could reduce Illinois energy prices by 2% (Kenneally and Stanfield 2014). These small percentages can result in large economic values. An ACEEE study showed that if utilities in Ohio met energy efficiency resource standards, the state would save $1.3 billion from wholesale capacity price mitigation through the year 2020 (Neubauer et al. 2013).

In addition to the reduced clearing prices measured by DRIPE, energy efficiency investments can deliver risk reduction benefits that constitute an additional dimension of their value. As we will discuss in detail, utilities can mitigate the risk of energy price volatility through various hedge mechanisms including long-term supply contracts. In effect, energy efficiency can serve as such a contract, providing energy resources at a fixed price and avoiding the need for utilities to purchase energy when demand and therefore prices are unexpectedly high. While it is possible to buy actual electricity in a long-term supply contract, energy efficiency provides the same risk-mitigating benefits but typically at a lower cost.

Our discussion proceeds as follows. First we outline the fundamentals of the PJM energy markets, including a discussion of the financial products used by market participants to minimize exposure to price fluctuations. Then we discuss documented experience of electric and gas utilities with risk management and hedging strategies. We describe an extreme weather event, the 2014 polar vortex, that caused extreme volatility in energy price and demand. We go on to discuss the value of energy efficiency in mitigating such volatility. Then we rely on one existing method in the literature to quantify the risk premium for PJM wholesale energy market prices for the 12-month period around the time of the polar vortex and the subsequent 12-month period. Finally, we outline how demand reductions could be used to minimize this risk premium, lowering costs for all customers.

Research Questions and Methodology

This report explores the following questions:

- What is the historical variation and volatility in PJM day-ahead and real-time energy prices? What are the trends associated with these prices?
- Are retail electric utilities exposed to day-ahead and real-time energy price spikes?
- What methods exist to determine the risk premium inherent in wholesale energy prices?
- Can energy efficiency (or other demand reductions) contribute to a reduction of wholesale energy price risk premiums?

To answer these questions, we rely on a blend of research methods including literature review, interviews with experts, and analysis of PJM market data. While we focus on the PJM wholesale electricity market, this research is applicable to other regional transmission operator (RTO) markets as well.

The data analysis in this study examines the nature of risk associated with electricity price volatility and its costs. We make an implicit comparison of those risks with other physical supply options and financial hedging strategies. Assessing the risks of those strategies is beyond the scope of this report, and we assume that those risks are accounted for when balancing the risks of purchasing power through the PJM market.

PJM Energy Market Fundamentals

PJM is the largest RTO in the United States. It coordinates delivery of electricity for 65 million people in 13 states and the District of Columbia, an area of more than 243,000 square miles. PJM maintains operational control of 82,000 miles of high-voltage transmission to manage the flow of electricity from more than 1,300 generators to its 990 members. It coordinates generation capacity exceeding 176,000 MW and delivers 792 million MWh annually (PJM 2017e, 2017g). Figure 1 shows the PJM service territory.

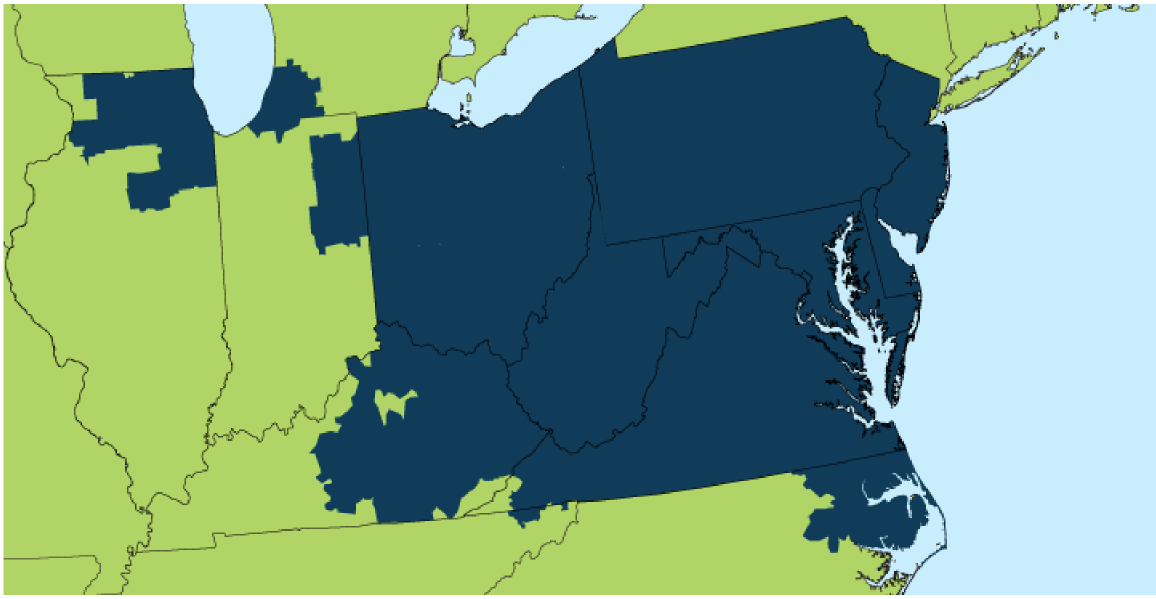

Figure 1. PJM service territory. *Source:* PJM 2018c.

PJM establishes energy and generating capacity prices within its service territory through several wholesale markets for wholesale electricity, generating capacity, transmission capacity, and ancillary services. These markets are composed of both physical commodities and financial products. They include:

- Day-ahead energy
- Real-time energy
- Capacity
- Regulation
- Synchronized reserves
- Day-ahead scheduling reserve
- Financial transmission rights

Long-term contracts are used to ensure adequate generating capacity and transmission rights.

THE DAY-AHEAD AND REAL-TIME ENERGY MARKETS

PJM operates two coordinated energy markets to ensure adequate supply of electric energy—the day-ahead and real-time markets. Within the day-ahead market, PJM uses generation offers, demand bids, and bilateral transaction schedules to develop hourly locational marginal prices for the next operating day (PJM 2016). However the day-ahead market does not always accurately match supply and demand. Because of this, PJM also operates the real-time market, where electricity is bought and sold in one-hour increments and five-minute increments in real time. Real-time market transactions are often much smaller in terms of energy and dollars than the day-ahead market, but the real-time market is important for pricing additional supply to meet unexpected demand.

LOCATIONAL MARGINAL PRICE

The price of an incremental unit of electricity at any specific location is known as the locational marginal price (LMP). LMP is composed of the marginal cost of energy, transmission line losses, and the cost of congestion. These three cost components are forecast and used to determine prices in the-day ahead market for every node in PJM, so that there are both day-ahead LMPs and real-time LMPs (PJM 2017a). Real-time LMPs are formed every five minutes when the loads report actual instantaneous demand and PJM determines dispatch for least-cost generation based on available capacity and constraints. These three components can be understood as follows:

Marginal Cost of Energy

This is the cost of one additional unit of energy without delivery losses or congestion. If all supply were offered into the market and purchased least-cost first, the cost of the last unit purchased would be the marginal cost of energy. It represents the point of confluence between supply and demand. Therefore, if there were no transmission losses or congestion, the LMP would equal the marginal cost of energy at every node in the marketplace.

Transmission Line Losses

These are the power losses that occur through heat loss during the transmission of electricity. The losses increase with distance, increased current flow, and conductor temperatures. Total losses throughout the entire PJM system on peak days can exceed 3,600 MW per hour (PJM 2007).

Congestion

Congestion is defined by PJM as the difference between the cost of an unsold, constrained low-cost source of generation and a higher-cost source of generation that gets purchased (PJM 2017b). Constraints occur because of thermal, voltage, and stability limits (or constraints) within the transmission system. When these constraints occur, the ability of the least-cost generator to deliver power demanded at a specific location is limited, and a higher-cost generator must be dispatched to meet that demand (PJM 2017b). These congestion costs are difficult to predict and can be very expensive; in the first three months of 2016, total congestion costs alone exceeded $292 million of the $39 billion PJM market (Walton 2017; PJM 2017d).

Risk in the Wholesale Market

Prices in PJM markets fluctuate for several reasons, exposing (through price premiums) utilities, power retailers, large industrial customers, and ultimately end-use customers to price volatility and risk. Figure 2 shows the top three components of total quarterly prices in PJM from 1999 through September 2017. The total price includes the locational marginal price (energy, losses, and congestion cost), transmission, and generating capacity.

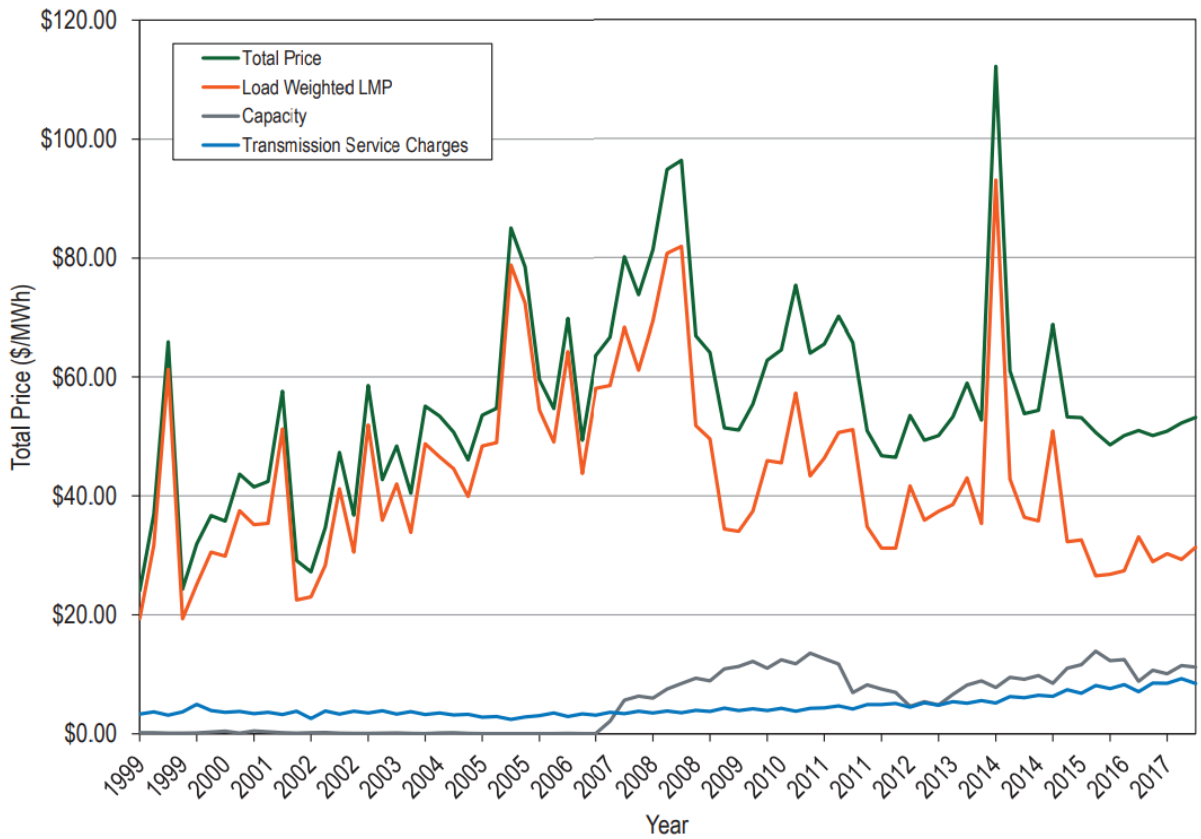

Figure 2. Top three components of quarterly total energy price ($/MWh), January 1, 1999, through September 30, 2017. *Source:* Monitoring Analytics 2017.

Electricity prices are both variable and volatile. Predictable price variation does not pose a threat to marketplace participants because they can prepare for the variation and properly allocate resources. Prices may fluctuate daily and seasonally but remain within a predictable range that does not upset normal market operations. Volatility, however, can cause lasting economic damage. Whereas variation in prices may be predictable and manageable, volatility typically is not.

Both generators and retailers are vulnerable to volatile markets and have limited means to recoup these costs. Generators are susceptible to volatility due to the regulations that require them to place their capacity in the PJM market and also place a cap on the price for which they can sell their energy. Likewise, retailers must meet demand but are selling at fixed prices while buying in a volatile market. In some cases utilities can pass through price increases to retail customers (see the section on customer exposure to price fluctuations below). However these customers typically pay a fixed rate for electricity over any given period of time. Therefore retailers cannot immediately recoup monetary losses due to price spikes in the wholesale market because they cannot transfer those spikes to end users in the form of higher prices until regulated utilities ask for and receive permission from public utility commissions to do so. Permission is not necessarily always given, and the time lag between the expense and the recovery of costs itself represents a cost to utilities, so that utilities typically incur some potentially significant costs when wholesale prices rise unexpectedly.

Utilities attempt to forecast demand as well as the probability that demand will exceed the supply under contract, by how much, and how much they will have to pay in the day-ahead or spot market to meet that uncovered demand. Unfortunately, since increased demand pushes up wholesale prices, periods of unexpectedly high demand typically have the highest unit prices attached to them, and the cost to utilities of being underinsured against periods of high demand can be quite high.

How Utilities Hedge Electricity Price Risk

Whenever there is price uncertainty in a market, there is risk. To avoid severe economic losses, any market player exposed to risk will characteristically seek strategies to mitigate it and engage in such strategies if they cost less than the cost of the risk they avoid. Electric utilities and other entities balance the risks of volatile energy prices in several ways, including physical hedges, most commonly long-term supply contracts at fixed prices, and financial hedges, which do not provide actual electricity but do provide financial compensation in the event that prices rise beyond a certain level.

Long-term contracts to purchase power at a fixed price typically set a price higher than current expected prices, so if prices do not exceed expectations, the purchasers of contracts pay more than they otherwise would have. As an example of a short-term contract, the Maryland Public Service Commission conducts quarterly auctions to procure the energy necessary to serve customers receiving energy service provided by the distribution company, acting as their default supplier. The quarterly auction allows Maryland regulators to balance the risk of price changes from one period to the next by procuring only 25% of future energy per auction. Contracts of longer length are naturally embedded with greater risk. This risk is largely a product of natural gas price uncertainty, as marginal energy prices in PJM are set primarily by natural gas–fired resources.

Utilities do not hedge all of their electricity purchases. Hedging is not free, and there is a point at which the cost of hedging is greater than the anticipated costs of purchasing electricity from spot markets. Financial hedges are costly; purchasers of electricity options are paying a price for the right to execute a contract to buy electricity at a given price some time in the future, regardless of whether they ultimately do so. These and other costs of hedging are commonly referred to as premiums, similar to insurance markets, because they offer insurance against high electricity prices.

Utilities must balance the cost of hedging against the anticipated cost of having to buy power in spot markets at high prices. Being over-hedged (e.g., buying more power in long-term contracts than is needed) results in utilities paying more for electricity when demand and prices remain at or below their expected levels. Being under-hedged (not buying enough) results in buying electricity in real-time markets when demand and prices are higher than expected. Both options involve risk, but the risks are highly asymmetric; the costs of being under-hedged generally are much higher than the costs of being over-hedged.

To see this, consider the common and conceptually simplest form of price hedging, long-term supply contracts. When utilities engage in long-term contracts, they agree to buy a certain amount of electricity at a known price over some amount of time. To lock in that supply at a known price, utilities generally have to pay more than what the price is expected to be. So if a utility is buying a MWh of electricity to be delivered in the middle of a weekday in January, it may expect spot market prices to be $40 per MWh but might be willing to pay $41 per MWh to limit exposure to higher prices caused by, for instance, extreme weather. In this example, the risk associated with buying the long-term contract is relatively low: If prices that day turn out to be average, the utility has lost $1 per MWh.

On the other hand, if the utility does not buy the long-term contract and there is an extreme weather event that drives up electricity demand and prices, the spot market price for a MWh might surge to $50 or $100—or, in the case of the 2014 polar vortex, as high as $1,800.[1] On a per-MWh basis, the upside risk is therefore much higher than the downside risk. Of course, the utility cannot know ahead of time if or when prices are going to jump, and it must try to balance the number of MWhs to hedge unnecessarily against the expected cost of buying power in the spot market for those MWhs it does not hedge.

FINANCIAL PRODUCTS

PJM marketplace participants use a number of financial products to mitigate price risk. Options, swaps, and futures can be bought and sold on the New York Mercantile Exchange (NYMEX) and the Intercontinental Exchange (ICE) (CME 2017; ICE 2017). These financial products exist for both the day-ahead and real-time marketplace for a number of hubs.

Forwards

An electricity forward is an agreement to supply a specific amount of electricity at a specific future date at an agreed upon price. The seller agrees to supply the specified electricity amount at the given time and date, and the buyer agrees to pay for the supply at the agreed-upon price. This is one of the most common strategies for trading electricity. Day-ahead market trades are a type of forward. Forwards can be as simple as bilateral trades and are generally nonstandardized agreements where physical electricity is traded (Deng and Oren 2006). Being nonstandardized and typically between two entities, counterparty risk can be a factor in this transaction.[2] Additionally, drawing up the terms of the contract may take longer than a more standardized product. While these contracts are smaller in number compared with the more standard futures contract, they are usually much larger in terms of the amount of electricity delivered (Deng and Oren 2006).

Futures

An electricity future is a type of standardized forward contract that can be traded on a financial exchange. Standardization means that the terms for the amount, timing, and other

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[1] In the 2014–2015 time period, hourly prices averaged about $38 per MWh. They dipped below $10 per MWh 19 times and spiked over $100 per MWh 188 times.

[2] Counterparty risk is the risk that one entity will not fulfill its contractual obligations.

legal requirements are the same as in other contracts. Futures tend to be nonphysical—in other words, settled by financial payments and not by delivery of electricity. Whereas forwards tend to trade larger amounts of electricity with a smaller number of transactions, futures tend to cover small amounts of electricity with a high volume of transactions. Additionally, futures are more transparent as they are listed in an exchange. Futures are seen to be more advantageous for some market participants because they take less time to set up and monitor, have less counterparty risk, and offer more transparency and liquidity (Deng and Oren 2006).

Swaps

A swap is a financial agreement between two parties in which one (here, the swap buyer) wishes to guarantee a fixed price for electricity, while the other (the seller) is willing to bear the risk of price fluctuations in return for a premium. The two parties set a fixed price higher than current prices. If market prices rise above this level, the swap seller pays the buyer the difference between market prices and the fixed price. If market prices fall below the fixed price, the buyer must pay the difference to the seller. The end result is that the swap buyer effectively pays the specified fixed price for electricity regardless of the actual market price. The swap seller receives the difference between the fixed price and actual market prices. Swaps typically cover a fixed quantity that can be drawn down over a period of 0–3 years (Deng and Oren 2006). The seller takes on the risk of price volatility and typically receives a premium in the form of a fixed price that is higher than current expected prices. The buyer receives price certainty but pays a premium for that security and risks overpaying if market rates stay below the agreed upon price.

Options

An option is a financial instrument that gives the purchaser the right (but not the obligation) to execute a contract for a commodity at a specified price (Hayes 2017). Common options used in electricity markets are call and put options, where the seller sells the right to buy or sell a fixed amount of electricity for a fixed price, but with a contract expiration date (Deng and Oren 2006). Option sellers are typically paid a premium for taking on the risk (a small percentage of the total contract amount) and are rewarded if the contract is never executed; they retain the premium and do not have to buy or deliver any electricity. Option buyers secure either a price floor for selling or a price ceiling for buying, insulating themselves from spikes for that time period.

Virtual Bids

There can also be virtual bidders in the marketplace, who buy or sell energy without necessarily being a retailer or generator. These virtual bidders buy or sell energy in the day-ahead market and then sell or buy, respectively, in the real-time market. This is an opportunity for traders to profit from arbitrage, but it is also a way for generators or retailers to hedge price risk (PJM 2017c).

Customer Exposure to Price Fluctuations

Vertically integrated utilities (those that still own generation capacity) may use various hedges for fuel and wholesale contracts. They often collect the costs associated with these hedge agreements through mechanisms called fuel adjustment clauses or fuel trackers. Such mechanisms allow them to collect costs outside of base rates as a pass-through; that is, they do not earn a financial return on these investments.

Utilities operating in deregulated environments divested their generation assets during restructuring. Many of them still offer customers supply service, with supplies often procured through a competitive auction process. The cost of supply is then recovered from retail customers in rates, also as a pass-through; the utilities do not financially gain from these sales. Because the costs of supply are treated as a pass-through cost, distribution utilities are protected financially from the risks of wholesale price volatility. However, since they are the entities that retail customers interact with, customers may blame them for high energy prices. Negative public sentiment may lead to adverse financial consequences from regulators in terms of reduced rates of return for failing to manage supply properly.

Customers' exposure to price fluctuations varies depending on the structure of the electricity market that serves them. As noted, most deregulated states operate competitive auctions for distribution companies to offer retail supply to customers. However the structure and frequency of these auctions vary. Some of the auction results are also reconciled with actual market results, exposing retail customers to price fluctuations. Table 1 shows the cost recovery practices for energy costs for some PJM states.

Table 1. Cost recovery practices for retail energy in select PJM states

State	RTO	Cost recovery for power costs
Delaware	PJM	Power to meet standard-offer-service (SOS) needs is procured competitively, and the resulting costs are reflected in rates.
District of Columbia	PJM	PEPCO, the sole electric utility serving the District, purchases the power to meet its SOS requirements via a competitive bidding process, and prices paid by SOS customers reflect the weighted average of the winning bids; SOS prices are adjusted.
Illinois	PJM/MISO	The power to meet the utilities' SOS obligations is procured competitively; SOS costs and revenues are subject to an annual true-up mechanism.
Maryland	PJM	Utilities provide electric supply service to customers who do not select an alternative generation supplier; the power to meet these requirements is obtained via competitive bids, and the costs are recovered from ratepayers.
New Jersey	PJM	Utilities procure power to meet customer basic generation service in the wholesale market and are permitted to pass these costs through to ratepayers on a dollar-for-dollar basis via the basic generation service charge. However costs associated with buyout/buy-down of above-market-priced purchased power contracts with nonutility generators and costs associated with any remaining purchase requirements are recovered through a separate non-bypassable charge.
Ohio	PJM	Utilities operate under electric security plans, or ESPs, that provide for the pass-through of the utilities' cost of power to serve SOS customers.

Source: Ernst and Bellizzi 2017

The table shows that most deregulated states in PJM and MISO allow utilities to pass through costs associated with retail supply. Some states, like Illinois and New York, reconcile or "true up" revenues with market results. Customers in these states are more directly exposed to increases in wholesale prices but are still mostly shielded from volatility through bilateral contracts between retailers and generators, instead paying premiums associated with various hedging strategies deployed by utilities. Approximately 10,000 ComEd (Illinois) residential customers are on real-time pricing and exposed to fluctuations in wholesale energy prices. Currently no other state in this region offers real-time pricing for residential customers.

The Polar Vortex

The strategies discussed above are used to manage the inevitable but unpredictable variations in electricity prices that occur regularly on a daily and hourly basis. If electricity markets experience extreme volatility, however, these commonly deployed strategies may be insufficient to insulate market participants from the costs of that volatility. Though extreme volatility events are less frequent than the more common and smaller price fluctuations, they are no less inevitable. Events like extreme weather and critical equipment failure can cause large price swings, sometimes over a protracted period.

It is important to consider the costs of both common and extreme price variations in assessing the risk-reduction value of energy efficiency investments and other hedging strategies. In this study we will consider data from two consecutive 12-month periods, June 2013 to May 2014, and June 2014 to May 2015. The second of these periods was a year of relatively normal weather and other conditions that produced commonplace volatility in prices on the PJM market. The first, however, included the winter of 2013–2014, in which the northeastern United States experienced a prolonged and extreme cold snap caused by a polar vortex.

In January 2014, record low temperatures and heavy snowfall caused both increased electricity demand and generation outages, leading to high energy prices in the PJM territory. Demand surged to more than 140,000 MW on January 7, and the cold weather continued: That month produced 8 of the 10 highest winter demands for electricity ever recorded in PJM (PJM 2014). At the same time, generator outages totaled nearly 40,000 MW, more than 20% of total capacity. The generator outages also increased the reliance on natural gas, a more expensive resource at the time due to its own price spikes caused by the polar vortex. Contractual constraints on natural gas generators, which required them to commit to specific volumes of gas purchases several days ahead of the actual day-ahead market for which they were being purchased, led to additional mismatches between available capacity and demand (PJM 2014). All these factors contributed to real-time power prices peaking at over $1,800 per MWh for four hours on January 14, with sustained high prices over the course of the event (RTO Insider 2014). Figure 3 shows the real-time and day-ahead locational marginal prices on January 14.

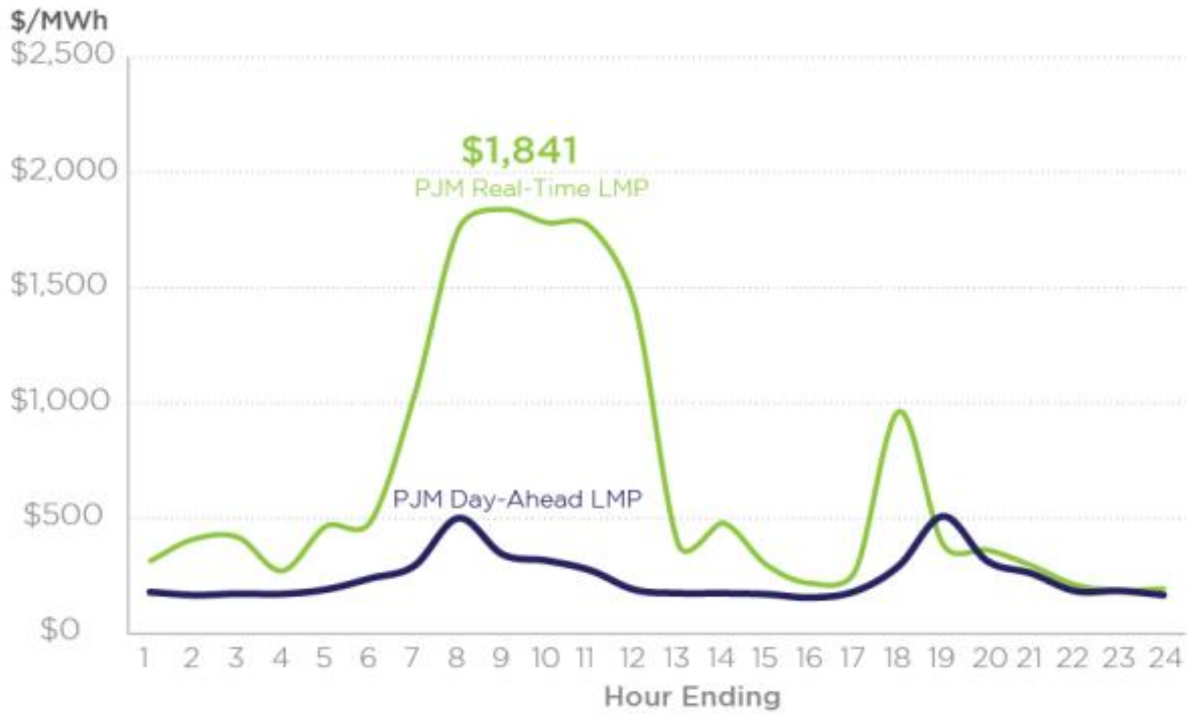

Figure 3. Day-ahead and real-time LMP on January 14, 2014. *Source:* PJM 2014.

On January 22, 2014, during the effects of the polar vortex, real-time prices in the PEPCO service area spiked at 6 AM to $415 per MWh; prices during the same hour seven days earlier, on January 15, had been just over $27 per MWh. This jump in prices was the result of surging demand that was about 50% greater than in the previous week. It cost PEPCO more than $500,000 in a single hour to cover that additional demand. The difference in the 8 PM hour was even worse. While demand was only 40% higher, covering that extra demand on the day-ahead and real-time markets cost PEPCO between $1 million and $3 million (PJM 2018a, 2018b).

PJM PLANNING AND RESPONSE

PJM estimated in late December 2013 that the approaching extreme weather could generate demand of 140,000 MW in early January, 20,000–40,000 MW higher than normal January peaks. PJM continually coordinated with generators and requested and received a waiver of confidentiality from FERC in order to review the day-ahead market bids and ensure that demand would be met. Later in the month, PJM requested and was awarded the ability to compensate the generators that had generation costs exceeding the $1,000-per-MWh ceiling on prices. FERC also granted permission for offers to exceed the cap, removing that price ceiling from the market temporarily (FERC 2014).

PJM also made an appeal to the public for conservation (FERC 2014). Specific guidelines for this type of appeal are detailed in PJM's emergency procedure plan.[3] In cold-weather events such as the vortex, they recommend limiting use of electric appliances and reducing thermostat set points, if possible (PJM 2017f). The 2014 appeal for conservation was shared with transmission owners, who in turn disseminated it to other stakeholders (PJM 2014). The message was covered by news outlets, which helped spread the appeal to customers (Akron Beacon Journal 2014).

Energy Efficiency as a Price Hedge

Investments in efficiency can reduce the risk premium inherent in the wholesale energy market by providing long-lasting energy savings at a fixed price. The costs of energy efficiency investments are most often expended in a single year and deliver savings over time. As a result, energy efficiency acts like a long-term contract for electricity at a fixed price that is not subject to the same fluctuations as the price of actual electricity. Moreover, unlike standard long-term contracts, efficiency investments do not include a price premium. In fact, the opposite is generally true: Efficiency tends to cost less than an equivalent amount of actual energy, delivering both energy services and risk reduction at a discount rather than a premium.

By reducing the need for utilities to purchase electricity through forward or spot markets, energy efficiency reduces not only the cost of the electricity supply but also the risk associated with price volatility and the cost of managing that risk. Efficiency may also reduce risk premiums in the long term. Risk premiums in long-term energy pricing reflect potential future volatility, which may be reduced by relying on fixed-price options like energy efficiency.

Since investments in energy efficiency typically require fixed up-front costs that provide a stream of future benefits, whether an efficiency investment makes sense at any point in time depends on whether the expected net present value of the energy savings is greater than the up-front costs. If future energy prices are expected to be low, the returns on any given energy efficiency investment go down and vice versa. However, since energy efficiency investments reduce the amount of electricity purchased at any given time, they reduce the amount of electricity purchased both during periods when prices are unusually high and during periods when they are unusually low. If the risk that electricity prices will be higher than expected is greater than the risk that they will be lower than expected, then efficiency investments provide additional value in terms of mitigating the risk of price volatility even when the long-term price trend is flat or moderately declining. Moreover, since energy prices can and often do fluctuate considerably even when prices are generally low, efficiency investments can provide an additional economic benefit in almost any energy price scenario.

[3] For more details on PJM's emergency procedure plan, see the most recent version of *PJM Manual 13: Emergency Operations* at pjm.com/~/media/committees-groups/committees/mrc/20171207/20171207-item-13d-draft-m13-revisions.ashx.

It is worth noting here that energy efficiency investments are not without their own risks. One important risk that we account for in our analysis is the risk that the price of a kilowatt-hour (kWh) of electricity will fall below the cost of delivering a kWh of energy efficiency. Like a long-term contract to purchase electricity at a given price, efficiency hedges against the risk that prices will increase but leaves the investor exposed to the risk that prices will fall. Another important risk, which we do not address quantitatively, is the possibility that efficiency investments will not perform as expected. Efficiency planners may overestimate the potential for savings and/or underestimate the costs of implementation. Efficiency equipment can fail before the end of its projected useful life or operate at below its expected capacity, either under-delivering or requiring repair. These and other factors introduce a degree of risk in efficiency investments that implementers should consider when determining the expected cost per kWh saved of efficiency investments.

Quantifying the Risk Reduction Value of Energy Efficiency

The value of the energy resource that efficiency represents is well understood, but the value of the fixed nature of the prices associated with it and the risk benefit that this confers is not often discussed, and few attempts have been made to quantify it.

Methodologies to quantify the risk reduction value of an instrument (such as energy efficiency or a financial instrument like a futures contract) are typically based on a comparison of the cost or premium of the instrument against the expected cost of the commodity being hedged. Here we discuss three methods to estimate the value of risk premiums in electricity prices.

TUOMINEN AND SEPPÄNEN METHOD

One approach used by Tuominen and Seppänen (2017) employs the Black–Scholes options pricing model to create and value a hypothetical financial hedge against rising electricity prices. Tuominen and Seppänen compared the cost of that hedge against the cost of end-use energy efficiency investments that would achieve the same level of protection against price risk. They used this method to calculate the risk-reduction value of adding fireplaces, heat pumps, and solar arrays to single-family homes to protect against rising costs of electricity for heating in Finland. They concluded that the value of the risk reduction was equal to about 10% of the annualized cost of the behind-the-meter energy investments they considered.

This result is interesting and important but has several relevant drawbacks. The approach assumes threshold levels of electricity prices that are high enough for residential consumers to be willing to insure against the risk of prices exceeding them.[4] The authors chose the admittedly arbitrary level of 40% above expected prices, which they assumed to be average current prices plus 2.5% inflation per year. Both inputs (price threshold and future price expectations) are necessary for the calculation, but neither is possible to define with

[4] Though uncommon, residential electricity customers in Finland are able to purchase electricity priced by spot markets, with the attendant price volatility.

certainty. While the price expectation assumption seems plausible, it is difficult to determine whether the 40% price increase threshold accurately represents the risk preference of consumers. The authors intended their calculation to be an example of how such a computation could be done, rather than a definitive quantification of the risk-reduction value of the efficiency measures they considered. The value of 10% that they derived is therefore not necessarily as precise as their method implies, and their assumptions, though plausible, are not as accurate as the method requires.

BOLINGER METHOD

Bolinger et al. (2002) used a conceptually similar methodology to quantify the risk-reduction benefits of energy efficiency to hedge against natural gas prices. They specifically examined this in the context of electric utilities' use of gas-fired generators (the marginal fuel in most regions) to meet electricity demand. In this case, they used the well-developed natural gas futures markets to determine the cost of locking in prices (specifically a 10-year price swap) and compared that with the Energy Information Administration's (EIA) natural gas price forecasts as a measure of expected spot market prices. Using data for California from 2000 and 2001, they found that long-term fixed gas prices available through futures markets were generally (but not universally) higher than long-term price forecasts, at times by as much as 60%. By comparing the present values of the costs of the 10-year swaps and the EIA price forecast, the authors determined that the market valued the risk reduction of the swaps to be roughly $0.76 per mmBTU, indicating a risk-reduction premium of 24%. The authors translated this into an electricity cost (using a conversion rate of 7,000 kBTU per kWh) of roughly 0.5 cents per kWh, which represented almost 15% of projected electricity prices at the time (AEO 2000).

This methodology does not try to identify the value of risk reduction from energy efficiency specifically. Rather, it identifies the market-determined maximum premium that wholesale natural gas customers (including electricity generators) would be willing to pay to avoid upside gas price risk. The implication is that utilities would be willing to pay a price premium of up to 24% for guaranteed access to gas supplies at a fixed price, and that the risk-mitigating benefits of energy efficiency in electricity markets would be worth the equivalent of 0.5 cents per kWh.

Unfortunately, it is difficult to apply either the Tuominen and Seppänen approach or the Bolinger option directly to electricity markets. The first methodology might be amenable to this question if we were willing to speculate about utilities' risk tolerance and long-term price expectations. The second methodology would require an estimate of price expectations as well as information on the price of futures contracts (or some other financial hedge) over 10 years. Neither of these is within the scope of this paper.

DICKERSON METHOD

A third methodology, described by Dickerson et al. (2003), estimates the cost of electricity price risk without these information requirements. This methodology calculates the value at risk (VAR) that utilities face due to volatile wholesale prices. Using hourly data from the California Power Exchange for calendar year 1999, Dickerson and colleagues assigned each hour to one of five time-of-use categories: summer peak, summer shoulder, summer off-peak, winter peak, and winter off-peak. Within each category, they broke the data down further into bins of hours when load was above the median for that category, delineating the bins in 5-percentage-point increments above median. Within each load bin, they calculated net VAR as the cost of satisfying demand when that cost was above the load-weighted average, minus the cost of satisfying demand when costs were below the load-weighted average. What is left is an estimate of the net cost of meeting demand from an unhedged position.

If prices are low enough during periods of low demand to offset the cost of purchasing high-priced power during periods of high demand, then VAR is negative, and there would be no value to hedging. The authors found that, since prices tend to be higher when demand is high, the VAR was generally positive, meaning that there would be some value to avoiding price volatility. The size of the VAR varied significantly among the five time-of-use categories. During summer peak hours, the cost of electricity acquisition averaged just under $47 per MWh while the VAR for that period was over $40 per MWh, representing an 85% risk premium. During winter off-peak hours, the cost of acquisition was just under $22 per MWh while the VAR was about $6.25, for a risk premium of 28%. Over the course of 1999, the authors found that the average risk premium was about 50% of the cost of acquisition.

It is important to note that net VAR represents an upper-bound estimate of the amount that utilities should be willing to spend to avoid price volatility. Calculated at a 95% confidence interval, it would assure utilities that there was only a 5% chance that they would have had to pay more than the net VAR for unhedged power.

Long-term contracts can be a low-cost method of taking a large share of total demand off the table. Utilities are willing to bear some risk, as evidenced by the fact that they do not buy forward contracts or hedges to cover all possible ranges of demand in all hours. Hedging against price risk is not without cost, and there are some situations in which utilities prefer to cover demand through spot-market purchases rather than through forward contracts. For this reason, net VAR is not a direct estimate of the risk-reduction value of energy efficiency. Rather, VAR gives an indication of how much risk energy efficiency and other hedging strategies can alleviate and provides an upper bound of the value of risk reduction that such strategies confer.

Analysis of VAR during and after the Polar Vortex

We use the methodology described in Dickerson et al. to calculate the net VAR associated with the price variability of electricity in the PJM service territory over the two consecutive 12-month periods of June 1, 2013, to May 31, 2014, and June 1, 2014, to May 31, 2015. The polar vortex anomaly occurred in January 2014, in the middle of the first of these two periods, which allows us to compare the first, with a distinct and extreme weather-driven demand spike, with the following 12 months, which lacked such a singular event.

Proceeding in a similar way to the method described in Dickerson et al., we broke each 12-month period into four time-of-use (TOU) categories: summer peak, summer off-peak, winter peak, and winter off-peak. We ranked the hours within each TOU category according to total load and divided them into the 11 percentile bins as described above, starting with the lowest 50% and proceeding with 10 additional bins, one for each remaining 5-

percentage-point increment. Within each bin, we created a 95% confidence interval around clearing price. The resulting net VAR for each bin was calculated on the basis of this 95% confidence interval and represents the net VAR for each bin with 95% certainty.

We broke the data into these bins in order to ensure that we were making apples-to-apples comparisons around the costs of price volatility. The historical method of calculating VAR that we employed relies on three basic data points within a given bin: the top price of the 95% confidence interval, the lowest price of the 95% confidence interval, and the mean price. It compares the difference between the upper price and the mean against the difference between the lowest price and the mean, netting the two differences to determine net risk. If we were to compute VAR based on a single bin that included all of the hours within a particular TOU, we would be comparing the upside risk in the most volatile and high-demand hours against the downside risk of the least volatile, low-demand hours. This would skew the net risk calculations considerably upward. By dividing the hours into percentile bins according to their load, we helped ensure that we would calculate risk by comparing prices in similarly volatile hours. This is a more relevant way to calculate risk since buyers plan their power purchases on the basis of the amount of load they expect in a given hour. The risk associated with those decisions should be calculated according to the probability that the actual price of power during an hour with a given amount of load will exceed the expected price of power during an hour with that given amount of load.

Table 2 shows the load-weighted average clearing price for electricity and VAR for each TOU category for two separate periods (2013–2014 and 2014–2015). The last column shows the load-weighted average price VAR for each 12-month period, in $ per MWh.

Table 2. Value at risk and price June 2013–May 2014 and June 2014–May 2015

	Summer peak	Summer off-peak	Winter peak	Winter off-peak	Weighted average
June 2013–May 2014					
Value at risk (VAR) ($/MWh)	11.3	13.7	50.9	9.3	13.9
Mean electricity price ($/MWh)	57.7	36.2	77.3	62.9	55.1
VAR as % of mean price	19.5%	37.9%	65.9%	14.7%	25.2%
June 2014–May 2015					
Value at risk ($/MWh)	13.2	3.4	18	3.7	5.6
Mean electricity price ($/MWh)	51.8	32.9	50.2	42.1	41
VAR as % of mean price	25.6%	10.5%	35.9%	8.9%	13.8%

It is clear by looking at the VAR during the winter peak hours of 2013–2014 that the polar vortex created a significant price and risk impact across the entire PJM territory. For context, it is important to note first that even during the less extreme year of 2014–2015, the average risk across all hours in all times of use was nearly 14% of the purchase price of electricity. A power purchaser that knew this ahead of time and wanted to eliminate price risk with 95% certainty would have to pay a premium of almost 14% above day-ahead prices to achieve that level of certainty. The premium was significantly higher in 2013–2014, when the risk associated with purchasing power was 25% of the purchase price.

Further research using data over longer periods could help determine how stable the 14% estimate is over time and how often more-extreme events occur, which would help planners determine how much risk they were likely to face over long planning horizons and how much it would likely cost them.

Table 2 demonstrates that the risk of price spikes is not uniform across all hours, and since volatility and load tend to rise and fall together, VAR tends to be higher during peak time-of-use periods. The polar vortex was an unusual event, and the day-ahead market during the 2013–2014 period exhibited higher levels of overall risk and much higher levels of risk during the winter months, with the implied risk premium rising to 66% of actual electricity prices. Even during off-peak hours of that winter, the VAR was significantly higher than it was the following year, driven by the high prices and high demand exhibited during the polar vortex.

The data from 2013–2014 show that average winter electricity prices, both peak and off peak, were well above what they were the following year and were in fact the highest average prices of the entire two years. The fact that the winter off-peak VAR was much lower than the winter peak VAR during the polar vortex is a reflection of the fact that, while prices during off-peak hours were unusually high, the price volatility was much more equally distributed between upside spikes and downside dips. A strategy of contracting for demand with low- but variable-cost power supplies would not have subjected power purchasers to an inordinate amount of risk.

Comparing the two summer off-peak periods also yields interesting results. Though average prices were similar, 2013–2014 had a VAR more than three times higher than the same hours in the following year. This emphasizes the point that while prices and volatility tend to move together, the correlation is not absolute. In the off-peak hours of summer 2014, the costs of meeting demand were high but stable, while in the following year they were high and volatile. The difference in these two is attributable to the fact that the amount of electricity demanded during periods of high prices was much higher in 2014 than it was in 2015. From a planning standpoint, a utility that planned to purchase an average number of MWs at a per-MW price in the mid $30 range in 2014 would likely have set aside sufficient funds to cover its costs. That same plan in the previous year would have left the utility spending significantly more than it had planned. Avoiding those extra, unplanned expenditures is the value that hedging provides.

Interestingly, the increased risks during the two winter peak periods were disproportionate to the increased prices. That is, prices were about 55% higher in the 2013–2014 winter peak period than they were in the same hours the following year, but VAR per MWh was 183% higher. The results for winter off-peak hours show a similar pattern. This difference is again the result of the large number of MWhs of electricity demanded during high-price hours.

Obviously, it is not appropriate to view the risk of an event after it has already taken place. Valuing risk is explicitly an ex ante exercise. However comparing a normal year to a year with highly volatile prices and demand allows an understanding of how much additional risk is generated by an extreme event.

Taking 2014–2015 as a more representative year, it is clear that even under more normal circumstances, the risk of price spikes is significant, averaging almost 14% of the cost of acquisition across the entire year. In contrast, the VAR in 2013–2014 was over 25% of the average cost of acquisition. In making long-term plans for electricity supply, utilities, regulators, and others should recognize that adding generation to the system entails not only the risk of volatility commonly experienced in average years but also the risk of extreme volatility of unusual years such as the one affected by the polar vortex. Given that the useful lifetime of electricity generating assets is measured in decades, it is probable that they will be subject to events like the polar vortex. For a unit with a useful lifetime of 30 years, the question is more likely to be how many times it will happen rather than whether it will happen at all.

While the costs of risk are significant year-round, load, prices, risks, and associated costs tend to move together. Figure 4 ranks all 44 TOU bins from 2014–2015 by the mean price within each bin and reports the upper and lower price bounds of the 95% confidence interval, mean price, and VAR, all in dollars per MWh.

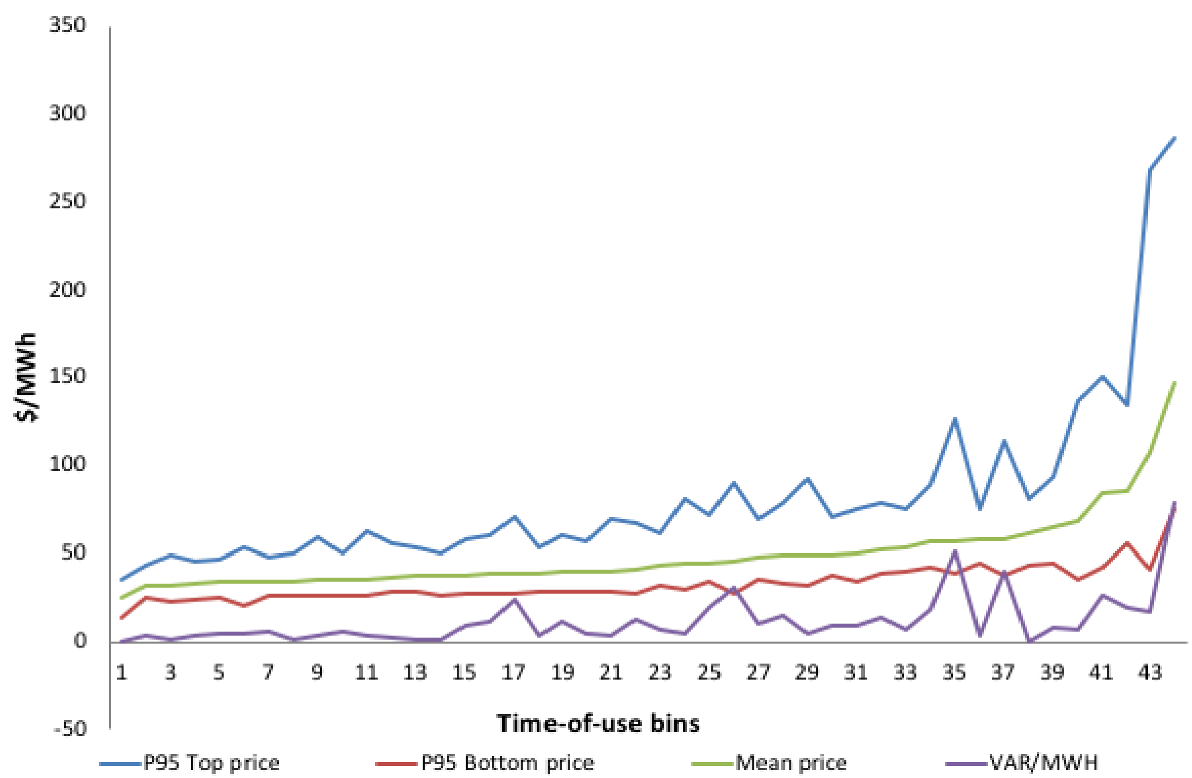

Figure 4. Ranking of all 44 TOU bins for 2014–2015 period

As shown in the chart, VAR tends to increase generally with mean prices, though there is substantial variation within that trend. Examining the individual bins, the five TOU percentile load bins with the highest mean prices—the top 5% of summer peak hours and the top 10% of hours during winter peak and winter off-peak hours—account for more than 25% of the total value of VAR (not per MWh) for the entire year. This is due to the combination of relatively high VAR per MWh and the large number of MWhs served during those hours.

LOCATION-SPECIFIC PRICE DIFFERENCES

The VAR analysis presented in the previous section demonstrates the price that market participants may be willing to pay to avoid risk of price fluctuations. The results rely on PJM's RTO-level data and do not capture location-specific differences in price. The actual VAR would vary by specific location throughout PJM. Figure 5 shows LMPs for the PJM market on July 19, 2013. The colors denote different ranges in price for wholesale energy. At the time of this snapshot, prices were higher in the eastern part of the service area, and prices ranged from below zero to $1,000 per MWh.

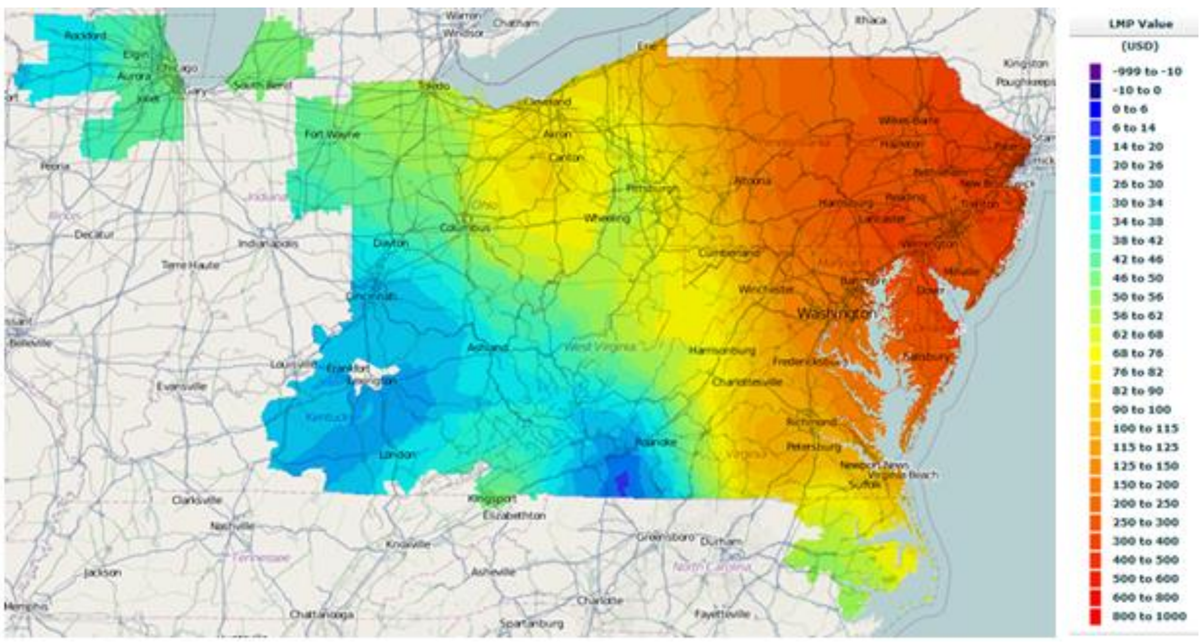

Figure 5. PJM real-time LMP on July 19, 2013, at 4:05 PM. *Source:* Avalon Energy Services 2013.

The figure demonstrates the variance in prices throughout the PJM footprint. These prices also fluctuate every five minutes, meaning the prices vary by time as well as location. Therefore the highest value of risk reduction would be in areas of high volatility. Although we chose to look at the RTO level in this study, an analysis of data specific to individual service territories could be valuable to individual utilities' planning efforts.

SUMMARY

The RTO-level VAR calculations highlight the fact that risks associated with price volatility are significant relative to the cost of electricity itself. Looking at June 2014–May 2015 as a representative year, the cost of risk averaged a nearly 14% price premium. In a year with an extreme weather event, the premium is even higher. One interesting extension of this methodology would be to cover a much longer period, say a decade, that includes stretches of representative demand interspersed with occasional demand spikes. Given that extreme weather events are inevitable, looking at a broader time range would provide a better measure of ongoing risk.

As mentioned previously, it is critically important to have a clear understanding of the risks associated with developing long-term supply plans, and this analysis shows that the costs associated with the risk of price volatility are significant. For any given hour of the June 2014–May 2015 period, utilities should have been willing to pay up to a 14% premium to reduce their exposure to risk—specifically, to be 95% sure that they would face no price risk at all. Energy efficiency is one possible strategy to hedge against risk, and the risk-reducing value of efficiency investments should be included in assessments of its cost effectiveness relative to electricity supply options.

It is important to note that while energy efficiency, long-term supply contracts, and financial hedges can all be useful ways to reduce the risk of price volatility, simply investing in generating assets with low and stable marginal costs is not. The reason is that all electricity sold during any given hour is priced at the same level: the price of the marginal MWh sold in that hour. Utility-scale supply resources such as solar or nuclear power with very low marginal costs are still sold at that clearing price and thus carry the same risk as other types of generation. Energy efficiency, by reducing the number of MWhs that are traded in any given hour at its associated LMP, reduces the overall exposure to price swings that low- and stable-cost supply options do not.

Long-term fixed-price contracts have the same hedging properties as energy efficiency. However long-term contracts sell at a premium in return for reducing the risk of volatility, while energy efficiency generally sells at a discount relative to electricity prices. As mentioned above, energy efficiency is not without its own risks, making the cost–benefit comparison between efficiency investments and other hedging strategies more complicated than a simple question of costs and risks avoided. However, to the extent that energy efficiency investments are not valued for their hedging properties, planners will deploy less efficiency than a more comprehensive analysis would indicate is appropriate.

Conclusion

Wholesale electricity prices fluctuate due to weather, fuel prices, critical equipment failures, and other events. Utilities and other power purchasers can reduce the risk of exposure to these price fluctuations in several ways. The most common is to purchase power forwards, which lock in a future price for electricity based on market projections. This type of hedge comes at a cost, but it allows a market participant to avoid risk of higher prices.

Energy efficiency investments, with their fixed up-front costs, are another way of hedging against wholesale price spikes and volatility. Like long-term contracts, efficiency investments reduce the amount of energy that must be purchased during high-price events. Unlike long-term contracts, however, energy efficiency does not typically sell at a premium to expected prices, but generally sells at a discount, making it both a lower-cost and lower-risk alternative to investments in generating assets.

In long-term resource planning, utilities and others must consider the risks associated both with normal price fluctuations and with occasional extreme events like the polar vortex.

Having a correct perception of these risks is critical to effective planning. In the creation of a plan that manages these risks and the costs of hedging against them, energy efficiency can play a role that has largely gone unrecognized so far. By offering electricity services at fixed and low prices, efficiency can reduce the amount of electricity that needs to be purchased when electricity prices are high, thus lowering overall system risk. To the extent that utilities, regulators, and other planners recognize this characteristic of efficiency, its overall value should increase in planning processes, and more efficiency resources should be deployed.

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