INITIAL COMMENTS ON THE 2014 ELECTRIC PROCUREMENT EVENTS PURSUANT TO SECTION 16-111.5(o) OF THE ILLINOIS PUBLIC UTILITIES ACT

PRESENTED TO

THE ILLINOIS COMMERCE COMMISSION

By

BOSTON PACIFIC COMPANY, INC.
AS THE COMMISSION'S PROCUREMENT MONITOR

Craig R. Roach, Ph.D.
Andrew Gisselquist
Katherine Gottshall
Boston Pacific Company, Inc.
1100 New York Avenue, NW, Suite 490 East
Washington, DC 20005
Telephone: (202) 296-5520

June 5, 2014

BOSTON PACIFIC
COMPANY, INC.

TABLE OF CONTENTS

I. INTRODUCTION

Boston Pacific Company, Inc. ("Boston Pacific") appreciates the opportunity to submit these comments in response to the Illinois Commerce Commission's (the "Commission's") Request for Comments concerning the spring 2014 request for proposal (RFP) to procure fixed quantity standard electric energy contracts with Commonwealth Edison Company (ComEd) and Ameren Illinois Company (Ameren).[1] Boston Pacific serves as the Commission's procurement monitor, as we have done for the Commission since 2006 and as we do for several other state commissions.[2]

The RFP solicited fixed quantity standard electric energy products for both utilities to meet a portion of their energy needs to supply customers in the 2014-2015 and 2015-2016 service years and in the 2016-2017 service year for Ameren. As required by the Illinois Public Utilities Act (hereafter, along with the Illinois Power Agency Act, collectively the "Acts"), two days after bid day Boston Pacific provided a confidential report to the Commission that presented the procurement results and assessed bidder behavior and compliance with the procurement processes and rules. In that report we recommended that the Commission accept the RFP results.

The bases for our recommendation were as follows: (a) the RFP process was open, fair, and transparent, (b) the procurement events were run in accordance with the requirements of the Acts and Commission-approved rules, (c) nearly all products solicited were procured, (d) the benchmarks were properly calculated and applied to the bids, (e) the process was sufficiently competitive, and (f) we did not identify concerns with the actions of any affiliates.

We structure our comments by first providing a summary of the results of this RFP (Section II). Second, we discuss the possible risks to the Illinois process from load shifting back and forth between utility default service and alternate retail electric suppliers (ARES). In recent years, the pattern of municipal aggregation and individual customer switching has been to shift load away from utility default service and towards ARES, but there is the possibility that this is

---

[1] Illinois Commerce Commission, "Public Notice of Informal Hearing (Request for Comments) Concerning the 2014 Electric Procurement Events Which Were Held On Behalf of Commonwealth Edison Company and Ameren Illinois Company," May 12, 2014.

[2] Specifically, in addition to Illinois, Boston Pacific has served or is serving as monitor for (a) New Jersey's 2007 through 2014 Basic Generation Service (BGS) Auctions, (b) the 2004-2005 through 2013-2014 Standard Offer Service (SOS) Request for Proposals (RFPs) for the District of Columbia, (c) Delaware's 2007 through 2010 SOS RFPs, (d) Maryland's SOS RFPs in 2004 through 2006 and 2010 through 2014 for all four utilities, (e) Allegheny (now West Penn) Power's 2009 RFP for full requirements supply in Pennsylvania, (f) First Energy Ohio's 2009 through 2014 Auctions for its Ohio Standard Service Offer (SSO) load, (g) Duke Ohio's 2011 through 2013 Auctions for its SSO load, (h) Dayton Power & Light's 2013 Auction for its SSO load and (i) AEP Ohio's 2014 Auction for its SSO load.

changing – a small portion of load has already returned to utility default service (Section III). Third, we touch on the discussion around this year's IPA Procurement Plan about changing the energy product from blocks of energy to a load-following product. We draw from our experience as monitors of default electricity service RFPs and auctions in other states to describe different load-following products (Section IV). Fourth, we discuss lessons learned from this winter's price spikes in PJM and MISO, including specific changes other states are making to customer education efforts and restrictions on switching between utility and third-party service (Section V). Fifth and finally, we have specific recommendations on the timing of future Illinois bid days (Section VI).

II. SUMMARY OF RFP RESULTS

The Ameren and ComEd spring 2014 RFP solicited energy to meet all or part of each utility's projected need for the three service years from June 2014 through May 2017, as specified in the IPA Plan and Commission Order. The products procured were energy contracts in 25 MW blocks, by month, in peak and off-peak segments. The energy is to be physically delivered to the utilities' respective load zones. The RFP procured nearly all (99.8 percent) of the utilities' stated energy need.[3]

The average winning price for Ameren peak energy was $47.76/MWh and for off-peak energy was $29.77/MWh. For ComEd, the winning prices were $46.42/MWh for peak and $27.79/MWh for off-peak energy. Directly comparing these prices would be ill-advised because the timing of need was different for each utility – Ameren sought proportionally more blocks in some months and ComEd more in others. The total value of the contracts signed as a result of the RFP was just over $340 million. NERA (the IPA's procurement administrator) calculated market-based benchmark values based on a methodology that had already been approved by the Commission. All winning bids were priced below these benchmark values, as required.

We recommended the Commission approve the results of the RFP because: (a) the RFP process was open, fair, and transparent, (b) the procurement events were run in accordance with

[3] When less than 100 percent of the sought-after quantities are procured the Acts instructs that "the procurement administrator, the procurement monitor, and the Commission staff shall meet within 10 days to analyze potential causes of low supplier interest or causes for the Commission decision." (220 ILCS 5/16-111.5(e)(5)(ii)) If changes are identified that would likely result in increased supplier participation, or that would address concerns causing the Commission to reject the results, the procurement administrator may implement those changes and rerun the RFP within 90 days. Commission Staff, procurement administrator, and Boston Pacific, as procurement monitor, understand this provision to mean that whenever any of the targets are not met all parties are to meet to determine if an additional RFP should be held to procure the unmet targets. The only unfilled blocks were two March 2017 blocks for Ameren. All parties met and decided that Ameren should not issue another RFP but, rather, attempt to procure the unmet targets through the energy RFPs that will be held in future years.

the requirements of the Acts and Commission-approved rules, (c) nearly all products solicited were procured, (d) the benchmarks were properly calculated and applied to the bids, (e) the process was sufficiently competitive, and (f) we did not identify concerns with the actions of any affiliates. The Commission approved the results of the RFP on May 2, 2014.[4]

III. POTENTIAL IMPACTS OF CUSTOMER SWITCHING ON DEFAULT SERVICE

Switching from utility default service to service from ARES has been popular in Illinois, especially via municipal aggregation, because until recently customers have been able to get much lower rates from ARES than from Ameren or ComEd.[5] As a result, roughly two-thirds of Ameren and ComEd residential customer load in Illinois is now served by ARES. However, switching has also increased the volatility of rates for customers who have remained on default utility service and will continue to do so when it causes unexpected change in utility load. This is important to remember in light of recent electricity market price volatility.

To understand the price risk that default utility service customers face from switching, recall that the winning suppliers in this RFP sell a fixed amount of electric energy at a fixed price. This does not mean that default service customers enjoy a completely fixed price. Ameren and ComEd buy and sell energy in the RTO market to reconcile the fixed amount of block energy already procured with the actual needs of default service customers. Customers on default service take the risk that this buying and selling by the utilities in the RTO market may increase or decrease the utilities' electricity rates. This price risk increases with the amount of energy the utility must transact in the market, relative to the amount of retail sales to default service customers. That is, any costs that the utilities face from transacting in the market will be spread among all default service customers. If there are more customers, each customer will face a smaller amount of this price risk. If there are fewer customers, meaning that more load has switched away from default service than expected, each customer will face a larger amount of price risk.

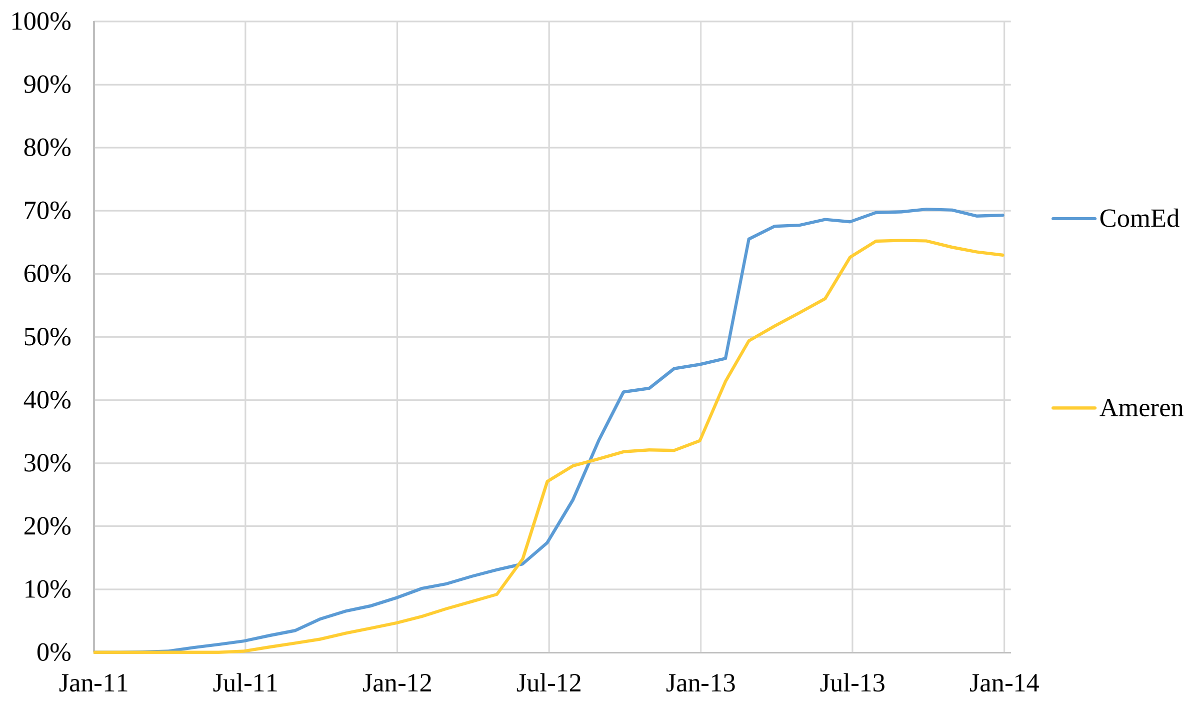
---

[4] Illinois Commerce Commission, "Public Notice of Successful Bidders and Average Prices, Ameren Illinois Company and Commonwealth Edison Company, Spring 2014 Procurement of Standard Energy Products", May 2, 2014.

[5] Several municipalities in Illinois have recently seen bids by ARES that have not been competitive with the default utility service rates and so have decided to switch from ARES back to utility default service. For example, Champaign, Illinois in Ameren's service territory is ending its municipal electric aggregation program June 2014 (http://ci.champaign.il.us/departments/public-works/residents/municipal-electric-aggregation/) and Lombard, Illinois in ComEd's service territory is ending its aggregation program in July 2014 (http://www.villageoflombard.org/index.aspx?NID=3895).

While switching away from default service to ARES leads to more price risk for remaining default service customers than does switching back to default service, the latter form of switching is not riskless. This is important to remember in light of the fact that, starting in the fall of 2013, switching reversed direction – more customers have been moving back to default service. Figure One, below, displays switching behavior of ComEd and Ameren residential customers from January 2011 through January 2014. After the 2010 municipal aggregation law passed, customers switched to ARES more quickly than expected. In preparation for the 2011 RFPs, ComEd had forecast that only about two percent of residential customers would switch from default service by June 2015 while Ameren had forecast that about ten percent would switch to ARES by May 2016. In reality though, residential switching for both ComEd and Ameren grew rapidly from 2011 through the beginning of 2013, peaking at over two-thirds of such load in September and October 2013. However, since then, through January 2014 (the most recently published switching statistics), a net one to two percent of residential load has switched back to default utility service.

Figure One
Percent of ComEd and Ameren Load (MWh) Supplied by ARES



Source: Utility filings with the Commission, Authors' calculations.

The recent switching behavior is likely due to the end of the ARES price advantage over utility default service. The swap contracts both utilities were required to have from 2008 through

2013 were above market price.[6] That boosted the price of default utility service, giving ARES an easy target. With the expiration of those higher priced swap contracts, utility default service prices are much more competitive with current market prices.

ARES customers may switch back to default service for many reasons. First, market prices could increase, making the default service product a better deal than could be offered by ARES. Second, we understand that ARES contracts are not required to have strong collateral protections, as do the contracts that default service energy suppliers sign with the utilities.[7] This may make it easier for ARES suppliers to walk away from unprofitable contracts; it also means that ARES customers may not be protected in case a supplier goes out of business. In such cases, customers could come back to default service. This possibility of an ARES contract ending prematurely was highlighted in the winter price spikes when Clean Currents, a third-party supplier in DC, Maryland and Pennsylvania, went out of business. Third, some ARES contracts that may appear to be fixed price actually allow pass through of the costs of high market prices. For example, according to *Crain's Chicago Business*, 98 municipalities in northern Illinois served by FirstEnergy Solutions were to be charged a proposed $5-$15 surcharge to offset high January power costs until public opposition to the surcharge led FirstEnergy Solutions to waive it.[8] Another supplier, Nordic Energy Services LLC, also requested recovery of the same costs from Hinsdale, Illinois.[9] Again, these contract terms make it more likely that ARES customers will return to utility service.

The risk to the price of default service is currently limited by the purchase electricity adjustment (PEA) rider. The PEA rider is calculated monthly and is, at least for ComEd, capped at no more than plus/minus 0.5 cents/kWh, with any excess in this account rolling over to future months. However, if there are high costs due to switching, the PEA rider may be elevated for a long time, or there may even be calls to loosen limits on the PEA rider. Either way, the risk that switching increases the price of utility service continues to be mainly borne by the ratepayers already on utility service, not by the customers that switch.

---

[6] These fixed quantity swap contracts were entered into in 2007 and deemed prudent pursuant to 220 ILCS 5/16-111.5(k). They included prices negotiated by the Illinois Attorney General's Office that increased each year between 2008 and 2013, during which period market electricity prices fell significantly.
[7] There are no legal requirements for ARES to offer any particular form of collateral. Additionally, to qualify as an ARES requires, at most, a $300,000 permit bond in favor of the People of the State of Illinois.
[8] Crain's Chicago Business, "FirstEnergy plans polar vortex surcharge on suburban electric bills", March 25, 2014; FirstEnergy, "FirstEnergy Solutions Waives Polar Vortex Surcharge for Residential Customers," April 25, 2014.
[9] Crain's Chicago Business, "Frigid Temps Spur Suburban Power Supplier to Hike Prices," February 27, 2014.

IV. STANDARD WHOLESALE ENERGY PRODUCT DEFINITION

There was discussion around this year's IPA's procurement plan about switching to a full requirements, load-following product. From the ratepayers' perspective, the major difference between wholesale block energy products and load-following full requirements products is that procuring a fixed quantity of block energy products leaves some market price risk with ratepayers, while soliciting a load-following product shifts that risk to the suppliers. However, shifting that market price risk away from ratepayers does come at a cost in the form of a risk premium on winning bids to supply load-following products. We fully agree with the Commission, Staff and the IPA that deciding whether to procure such a product is a policy question. In order to be of assistance on that question, we offer some facts about such a product, based on our experience as monitor for procurements of full-requirements, load-following products in several other states: Maryland, New Jersey, Ohio, and the District of Columbia.[10]

District of Columbia

Each year the utility in DC, PEPCO, procures one-third of its residential and small commercial load via a three-year full requirements product and procures all of its large commercial load via a one-year full requirements product. These procurements happen over two bid days, usually in early December and early January. Suppliers bid on tranches of either (a) residential and small commercial load or (b) large commercial load, where each tranche is a load following product for a fixed percentage of PEPCO's load. Suppliers provide full requirements service, including all elements of wholesale electricity supply – energy, capacity, ancillary services, renewable energy obligation, and losses – except for network integrated transmission service.

Maryland

Maryland's four major utilities procure their supply in separate, but simultaneous quarterly RFPs – the utilities' bid days are held at the same time. Suppliers bid on tranches of a full requirements, load-following product, split up by customer types. Winning suppliers have an obligation to supply a given percentage of a utility's retail load for a specific customer type. Therefore, this is a load following product. Two-year contracts are solicited for residential and small commercial load; each year 50 percent of the need is solicited. Large commercial load is supplied via three-month contracts, so 100 percent of that load is solicited each quarter. The Maryland product includes all components of full requirements wholesale supply service –

[10] We note that the IPA scheduled a workshop to discuss this issue on June 5, the same day these comments are due.

energy, capacity, ancillary services, renewable energy obligations and losses – except for network integration transmission service.

In order to mitigate suppliers' exposure to the risk associated with customer migration for its residential and small commercial products, Maryland incorporates a volumetric risk mechanism. In case of an increase in load above a set amount, which could occur if many customers migrated from third-party service back to utility service, the utility will be responsible for meeting the additional load by buying electricity from the PJM market. The cost of these purchases will be passed through to all utility default service customers. As a result, suppliers' risk is lower than it would be if they were required to follow load exactly because ratepayers accept the risk of a surge in demand above a certain level.

New Jersey

The four New Jersey utilities all procure their default service supply together, in the same auction. The residential and small commercial product is a three-year, fixed price, load-following product. In the auction to solicit this service, potential suppliers bid on tranches, or portions of each utilities' load. Each tranche is sized to be about 100 MW of peak load from all customers that are eligible to take default service. Suppliers also provide transmission, capacity, ancillary services, any other load serving entity services required by PJM, and renewable portfolio standard compliance.

New Jersey's large commercial product is a one-year load-following product for a fixed percentage of a utility's commercial and industrial load, whatever that amount turns out to be. Each year the utilities bid out 100 percent of their commercial and industrial supply needs. Winning bidders in this auction provide a full requirements service but are paid the spot market price for providing energy, $6/MWh for providing ancillary services, and a standby fee of $0.15/MWh. This means that the price they offer into the commercial and industrial auction is meant to essentially cover (a) the cost of capacity and (b) the cost of meeting New Jersey's RPS.

Ohio

Each utility in Ohio separately procures load-following supply for its default service customers, so the product varies somewhat between utilities. For simplicity, here we discuss the product procured by the FirstEnergy Ohio utility. The term of the full-requirement contracts that FirstEnergy has solicited varies from auction to auction, but typically ranges from one to three years. Each product is a tranche, equal to one percent of the actual hourly energy required to supply all of FirstEnergy Ohio's default service customers. In addition to energy, suppliers also provide transmission, capacity, ancillary services, and any other load serving entity services required by PJM. Suppliers do not provide renewable portfolio standard compliance.

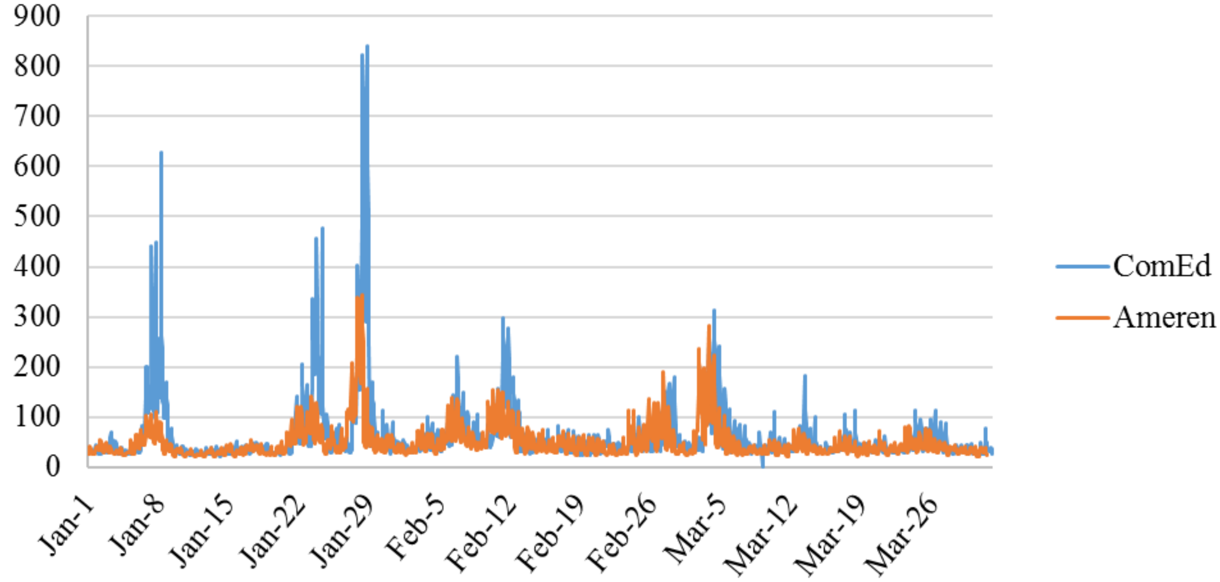
Note that another Ohio utility, AEP Ohio, solicits a load-following energy only product. This product does not require the supplier to provide capacity, transmission, ancillary services, or renewable portfolio standard compliance.

V. LESSONS LEARNED FROM WINTER 2014 PRICE SPIKES

This winter saw multiple instances of severe price spikes in PJM and MISO spot market prices. For Illinois, price spikes can have mixed effects. To the extent that Ameren or ComEd has contracted for more supply during a price spike than is needed by their default utility service customers, the ability to sell the excess energy at high prices is a benefit to ratepayers. However, to the extent the utilities need to buy electricity, ratepayers will face the added cost. Additionally, whether utilities buy or sell energy during a price spike, the price spike can increase the price of electricity in the future. This occurs because the price spike can make the market more risk averse, increasing electricity futures prices and the cost of purchasing standard electric energy contracts. Because of these impacts, in this section we discuss PJM's and MISO's examinations of the causes of this winter's price spikes, draw out some lessons learned, and discuss actions that other states are taking in response to customer complaints.

In January, PJM and MISO spot market prices spiked, most notably during the periods January 6-8 and January 17-29. These price spikes were higher for PJM, ComEd's regional market, than for MISO, Ameren's regional market. This is shown in Figure Two below, which displays the PJM and MISO day-ahead hourly prices at the delivery zones for the ComEd and Ameren zones. Prices also spiked in February and March for both utilities, most notably on February 10-12 and again on March 3-4.

Figure Two
ComEd and Ameren Zones, Jan – Mar 2014 Day-ahead Hourly LMP prices ($/MWh)



1. The ComEd Zone is the delivery point for the ComEd wholesale energy product.
2. The Ameren Zone (AMIL.BGS6) is the delivery point for the Ameren wholesale energy product.

Source: PJM and MISO LMP data.

Causes

PJM and MISO studied these price spikes and concluded that they began with extremely low temperatures. These low temperatures pushed demand to record levels, caused significant generator outages, and led to difficulties with delivering interruptible natural gas supplies. The record levels of demand and problems with natural gas delivery combined to push up natural gas prices and in turn cause electricity price spikes.

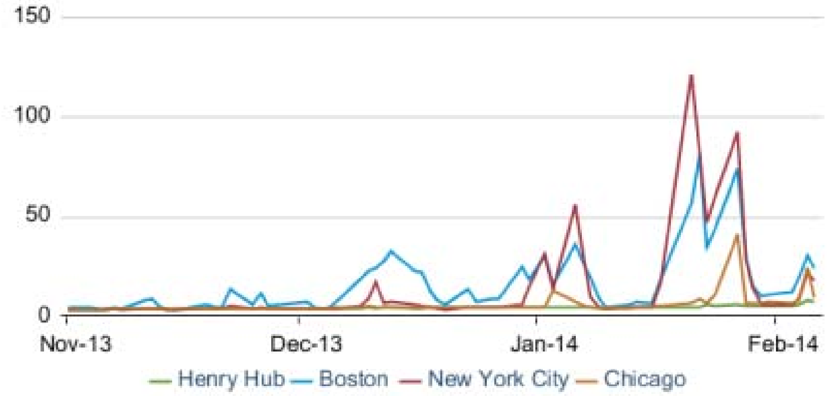
Both PJM and MISO saw record demand this winter. Eight of the ten highest all-time winter demands for electricity in the PJM region occurred this January.[11] MISO also set a new all-time winter peak load; on January 6 MISO's peak load was over 9 percent higher than the previous peak.[12]

---

[11] PJM Interconnection, *Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events*, May 8, 2014, 32, Figure 22.
[12] MISO, "January 2014 Extreme Weather Event – MISO Preliminary Review (01/10/2014)"

The cold weather and high energy usage increased demand for natural gas and, combined with limits on transport capability, created large price spikes across much of the northern and eastern US. Prices for natural gas in Illinois were not as high as in the Northeast, but daily prices for natural gas in Chicago closed as high as $41.31/MMBtu on January 27. Figure Three below shows the spot price of natural gas at several locations soaring even while prices at Henry Hub in Louisiana did not see the same price spikes. The high natural gas prices were a major driver for the price spikes in ComEd and Ameren's day-ahead LMP prices.

Figure Three
Natural Gas Spot Prices ($/MMBtu)

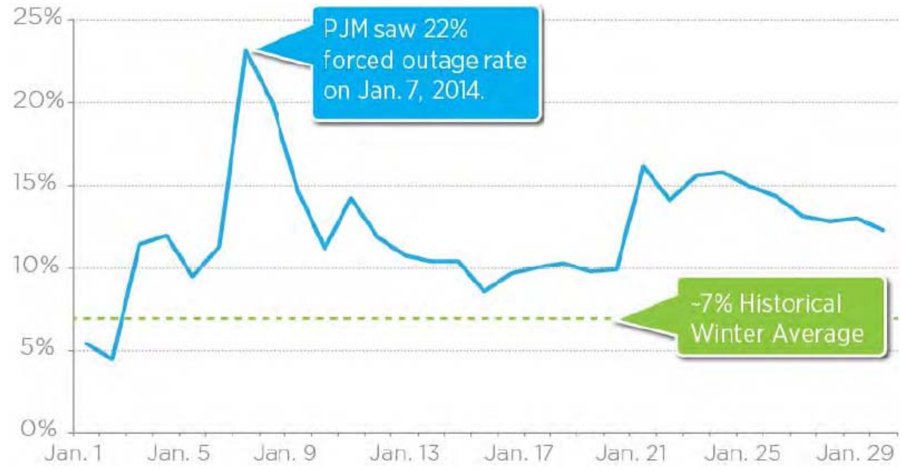


Source: U.S. Energy Information Administration, *Short-Term Energy Outlook Market Prices and Uncertainty Report*, February 11, 2014, p. 10, figure 13.

Additionally, many power plants in PJM and MISO experienced forced outages. For example, between January 6 and January 8, PJM experienced 40,200 MW of unexpected outages, amounting to 22 percent of its total generating capacity.[13] Around the same time, MISO experienced 24,562 MW of unexpected outages.[14] As can be seen in Figure Four, forced outages in PJM remained elevated during the second cold snap in January, reaching over 15 percent of installed capacity, or roughly twice the seasonal average of about 7 percent.

[13] PJM Interconnection, *Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events*, May 8, 2014, pp. 24, 26.
[14] *MISO's Response to Questions from the United States House of Representatives, Committee on Energy and Commerce, on 2014 Winter Cold Weather Events*, April 18, 2014, p. 2.

Figure Four
PJM Morning Peak Forced Outage Rate as Percent of Installed Capacity



Source: PJM Interconnection, *Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events*, May 8, 2014, p. 24.

There were a number of major causes of these high levels of forced outages. According to PJM, equipment issues with both coal and natural gas units made up the bulk of forced outages. In some periods, curtailments of natural gas supply to plants relying on interruptible supply also was a significant factor. PJM estimates that in the hour of peak demand on January 7, about 9,300 MW (roughly one-quarter of the forced outages at that time) were due to lack of gas supply; MISO estimates that on January 7 there were 6,666 MW of gas related forced outages.[15]

Outages in the second half of January were not driven as much by natural gas supply curtailments, though both PJM and MISO cited issues with gas scheduling that raised costs, particularly over the long Martin Luther King holiday weekend. For example, some plant operators asked PJM to "commit their units on the preceding Friday... to run through the entire weekend to assure gas was available for the following Tuesday morning."[16] That is, to ensure that natural gas plants were able to run for the few hours they would be needed, PJM had to run some natural gas plants out of dispatch order, despite high natural gas prices. Because outages in this second period were not as high as PJM had experienced in early January, PJM ended up overscheduling generation. This left a greater amount of expensive generation running than was needed, which also led to higher costs. In addition, due to PJM running some units out of order

[15] Ibid., 24-26 and *MISO's Response to Questions from the United States House of Representatives, Committee on Energy and Commerce, on 2014 Winter Cold Weather Events*, April 22, 2014, p. 2.
[16] *Statement of Michael J. Kormos Executive Vice President – Operation PJM Interconnection, L.L.C.*, FERC Docket AD14-8-000, April 1, 2014, p. 11.

to meet the anticipated need, PJM faced substantial uplift charges. All of this led to higher RTO market prices. We note that despite all of these strains, there were no blackouts and energy grids succeeded in delivering power to ratepayers.[17]

Initial Lessons Learned

For Illinois, there are at least four takeaways from the price spikes. First, these incidents highlight the value of utility default service. Experience in other states highlighted the fact that the default service stands ready to serve when third-party suppliers fail. For example, Clean Currents, a third-party supplier in DC, Maryland and Pennsylvania, went out of business and to our knowledge the default service was able to accommodate the addition of new customers smoothly.

Second, these incidents highlight the fact that price spikes are still a possibility even in the age of more abundant natural gas supply. Gas prices have been stable due to vast reserves of shale gas being developed, but here we see that a combination of extreme demand, limited pipeline capacity, and generating facility outages worked to drive prices up.

Third, these price spikes highlight the value of a fixed price electricity product, either as a default service or from third party suppliers. When used, such fixed price products provided protection for rate payers against volatile spot prices. Although energy products that shift risks to suppliers do come at the cost of added risk premiums, such costs have to be balanced against the value of reducing customers' exposure to price volatility and, therefore, to large potential bill increases.

Fourth, the winter price spikes highlight the value of contingency planning for the default service RFPs in case of a "bad day" that keeps suppliers from bidding and/or keeps prices unreasonably high. Though Illinois saw good participation in the spring RFP this year – after the price spikes had subsided – our experience is that default service procurements in other states during the price spikes saw lower than expected levels of participation. These states had acceptable results, but the lower levels of participation remind us that market uncertainty will affect default service procurements. For example, Maryland saw very low participation for its quarterly solicitation for default service for all four of its EDCs on January 27 – right in the middle of the second wave of PJM price spikes. This solicitation mainly sought default service supply for commercial customers in the form of three-month contracts with delivery starting

[17] PJM Interconnection, *Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events*, May 8, 2014, 4.

March 1, 2014.[18] Typically the process attracts 5 to 6 MW bid for every MW needed, but this solicitation saw just 2.1 MW bid for every MW needed.[19] Again, this was for a product that began delivery in March. In Delaware, a February 3 residential default service bid day saw just four bidders as compared to seven on a bid day in December.[20]

Action in Other States on Customer Education and Third-Party Service

The winter price spikes also led to an increased number of complaints from customers about higher bills. For example, the Citizens Utility Board in Illinois released a report in May that reported a 115 percent increase in consumer complaints about alternative electric suppliers; the number one reported complaint was high rates.[21] This fits with what we have heard from other states, where customers may not have known that they were on variable rate electricity service or, even if they knew that their rates were variable, they did not understand how high those rates could go.

These complaints in Illinois and other states highlight that many customers are unaware of the risks of variable rate plans and could benefit from increased customer education. Notice of these risks should come before a customer finishes enrollment in a variable rate service as well as before a customer transitions to variable rate service from fixed price service, as can happen when a fixed rate offer expires and becomes a variable rate. Several other states have begun considering and implementing additional education efforts around variable rate third-party electricity service. For example, the Pennsylvania PUC recently established a simplified form of disclosure and noticing regarding items like price offers, price volatility, and changes in rates.

Some states are also examining complaints about delays in switching from a spot-priced service to a fixed-rate service, delays which exposed consumers to more price volatility. For example, the Pennsylvania PUC passed regulations to reduce the time it takes to switch from a third-party supplier to utility default service to three business days. The Maryland Commission recently opened a docket to examine billing options, termination of service, and other issues related to the price spikes and has called for a customer switching time of three to five business days. Any similar policy proposal in Illinois should consider that Illinois has a robust municipal aggregation program. If such a policy would allow municipalities to quickly switch between

[18] "Direct Testimony of Frank Mossburg, Boston Pacific Company, Inc. on Behalf of the Staff of the Public Service Commission of Maryland," *Case Nos. 9056 and 9064, Before the Public Service Commission of Maryland*, January 30, 2014, pp. 3-4.
[19] Ibid., pp. 5-6.
[20] The Liberty Consulting Group, Inc., *Technical Consultant's Final Report To the Delaware Public Service Commission: Delmarva Power & Light's 2013-14 Request for Proposals for Full Requirements Wholesale Electric Supply for Standard Offer Service*, March 4, 2014, 7.
[21] Citizens Utility Board, *The Illinois Electric Market*, May 13, 2013, p. 2

utility and ARES service, it could significantly increase the volatility of utility load, leading to more market transactions for the utilities, and increasing price risk for existing default service customers, as described above.[22]

VI. TIMING OF BID DAY

As a final topic, we want to suggest that the IPA and others creating the RFP schedule keep in mind the following three ideas about bid day timing. First, ideally the timing of bid day will allow for a contingency procurement event to occur before the contracts are to begin delivery on June 1. This means that in case the bid day fails to procure a significant portion of targeted supply (a) all parties can meet to discuss this shortfall, (b) a contingency bid day can be held, and (c) contracts from that second bid day can be finalized before June 1. If a second set of contracts cannot be finalized before June 1, a utility can always purchase any needed supply for June at spot market prices, but this should be a last resort, not a contingency plan.

Second, to the extent possible, the Illinois bid day should not conflict with already scheduled bid days in other PJM or MISO states. While it is not always possible to avoid overlapping with other bid days, it is a good goal because it helps increase bidder participation.

Third, bid day should be scheduled for a Monday, if possible. Because the law provides for up to four days between bid day and a Commission decision, holding bid day on a Monday ensures that bidders will not have to hold their bids open over a weekend. Minimizing the amount of time that bids are held open has the potential to lower risk premiums that bidders attach to their bids.

[22] For comparison, it takes at least until the next meter reading date to switch providers in Illinois.