Energy Market

The PJM Energy Market comprises all types of energy transactions, including the sale or purchase of energy in PJM's Day-Ahead and Real-Time Energy Markets, bilateral and forward markets and self-supply. Energy transactions analyzed in this report include those in the PJM Day-Ahead and Real-Time Energy Markets. These markets provide key benchmarks against which market participants may measure results of transactions in other markets.

The Market Monitoring Unit (MMU) analyzed measures of market structure, participant conduct and market performance for the first six months of 2016, including market size, concentration, residual supply index, and price.[1] The MMU concludes that the PJM energy market results were competitive in the first six months of 2016.

Table 3-1 The energy market results were competitive

Market Element	Evaluation	Market Design
Market Structure: Aggregate Market	Competitive	
Market Structure: Local Market	Not Competitive	
Participant Behavior	Competitive	
Market Performance	**Competitive**	**Effective**

- The aggregate market structure was evaluated as competitive because the calculations for hourly HHI (Herfindahl-Hirschman Index) indicate that by the FERC standards, the PJM Energy Market in the first six months of 2016 was moderately concentrated. Average HHI was 1073 with a minimum of 837 and a maximum of 1356 in the first six months of 2016. The fact that the average HHI was in the moderately concentrated range does not mean that the aggregate market was competitive in all hours. It is possible to have an exercise of market power even when the average HHI is unconcentrated. The PJM Energy Market peaking segment of supply was highly concentrated.
- The local market structure was evaluated as not competitive due to the highly concentrated ownership of supply in local markets created by transmission constraints. The results of the three pivotal supplier (TPS) test, used to test local market structure, indicate the existence of market power in local markets created by transmission constraints. The local market performance is competitive as a result of the application of the TPS test. While transmission constraints create the potential for the exercise of local market power, PJM's application of the three pivotal supplier test identified local market power and resulted in offer capping to force competitive offers, correcting for structural issues created by local transmission constraints. There are, however, identified issues with the application of market power mitigation to resources whose owners fail the TPS test that need to be addressed.
- Participant behavior was evaluated as competitive because the analysis of markup shows that marginal units generally make offers at, or close to, their marginal costs in both Day-Ahead and Real-Time Energy Markets, although the behavior of some participants both routinely and during periods of high demand is consistent with economic withholding.
- Market performance was evaluated as competitive because market results in the energy market reflect the outcome of a competitive market, as PJM prices are set, on average, by marginal units operating at, or close to, their marginal costs in both Day-Ahead and Real-Time Energy Markets, although high markups during periods of high demand did affect prices.
- Market design was evaluated as effective because the analysis shows that the PJM Energy Market resulted in competitive market outcomes. In general, PJM's energy market design provides incentives for competitive behavior and results in competitive outcomes. In local markets, where market power is an issue, the market design identifies market power and causes the market to provide competitive market outcomes. The role of UTCs in the Day-Ahead Energy Market continues to cause concerns.

PJM markets are designed to promote competitive outcomes derived from the interaction of supply and demand in each of the PJM markets. Market design itself is the primary means of achieving and promoting competitive

1 Analysis of 2016 market results requires comparison to prior years. In 2004 and 2005, PJM conducted the phased integration of five control zones: ComEd, American Electric Power (AEP), The Dayton Power & Light Company (DAY), Duquesne Light Company (DLCO) and Dominion. In June 2011, PJM integrated the American Transmission Systems, Inc. (ATSI) Control Zone. In January 2012, PJM integrated the Duke Energy Ohio/Kentucky (DEOK) Control Zone. In June 2013, PJM integrated the Eastern Kentucky Power Cooperative (EKPC). By convention, control zones bear the name of a large utility service provider working within their boundaries. The nomenclature applies to the geographic area, not to any single company. For additional information on the control zones, the integrations, their timing and their impact on the footprint of the PJM service territory, see the *2015 State of the Market Report for PJM*, Appendix A, "PJM Geography."

outcomes in PJM markets. One of the MMU's primary goals is to identify actual or potential market design flaws.[2] The approach to market power mitigation in PJM has focused on market designs that promote competition (a structural basis for competitive outcomes) and on limiting market power mitigation to instances where the market structure is not competitive and thus where market design alone cannot mitigate market power. In the PJM Energy Market, this occurs primarily in the case of local market power. When a transmission constraint creates the potential for local market power, PJM applies a structural test to determine if the local market is competitive, applies a behavioral test to determine if generator offers exceed competitive levels and applies a market performance test to determine if such generator offers would affect the market price.[3] There are, however, identified issues with the application of market power mitigation to resources whose owners fail the TPS test that can result in the exercise of local market power. These issues need to be addressed. There are issues related to the definition of gas costs includable in energy offers that need to be addressed. There are currently no market power mitigation rules in place that limit the ability to exercise market power when aggregate market conditions are tight. If market-based offer caps are raised, or if generators are allowed to modify offers hourly, market design must reflect appropriate incentives for competitive behavior and aggregate market power mitigation rules need to be developed.

Overview

Market Structure

- **Supply.** Supply includes physical generation and imports and virtual transactions. Average offered real-time generation increased by 458 MW, 0.29 percent, in the first six months of 2016 from 156,679 MW in the first six months 2015 to 157,137 MW in the first six months 2016. In the first six months of 2016, 4,634.9 MW of new capacity were added and 706 MW were retired.

  PJM average real-time generation in the first six months of 2016 decreased by 3,762 MW, or 4.2 percent, from the first six months of 2015, from 90,097 MW to 86,335 MW.

  PJM average day-ahead supply in the first six months of 2016, including INCs and up to congestion transactions, increased by 10.9 percent from the first six months of 2015, from 115,148 MW to 127,748 MW, primarily as a result of an increase in UTC volumes.

- **Market Concentration.** The PJM Energy Market was moderately concentrated overall with moderate concentration in the baseload and intermediate segments, but high concentration in the peaking segment.

- **Generation Fuel Mix.** During the first six months of 2016, coal units provided 32.2 percent, nuclear units 36.5 percent and gas units 25.7 percent of total generation. Compared to the first six months 2015, generation from coal units decreased 16.3 percent, generation from gas units increased 21.7 percent and generation from nuclear units increased 2.0 percent.

- **Marginal Resources.** In the PJM Real-Time Energy Market, in the first six months of 2016, coal units were 44.39 percent of marginal resources and natural gas units were 43.38 percent of marginal resources. In the first six months of 2015, coal units were 32.85 percent and natural gas units were 56.12 percent of the marginal resources.

  In the PJM Day-Ahead Energy Market, in the first six months of 2016, up to congestion transactions were 83.3 percent of marginal resources, INCs were 3.8 percent of marginal resources, DECs were 7.3 percent of marginal resources, and generation resources were 5.5 percent of marginal resources. In the first six months of 2015, up to congestion transactions were 74.1 percent of marginal resources, INCs were 5.4 percent of marginal resources, DECs were 9.1 percent of marginal resources, and generation resources were 11.0 percent of marginal resources.

- **Demand.** Demand includes physical load and exports and virtual transactions. The PJM metered system peak load during the first six months of 2016 was 134,958 MW in the HE 1700 on June 20, 2016, which was 8,157 MW, 5.7 percent, lower than the PJM peak load for the first

2 PJM. OATT Attachment M (PJM Market Monitoring Plan).
3 The market performance test means that offer capping is not applied if the offer does not exceed the competitive level and therefore market power would not affect market performance.

six months of 2015, which was 143,086 MW in the HE 0800 on February 20, 2015.

PJM average real-time load in the first six months of 2016 decreased by 5.3 percent from the first six months of 2015, from 90,586 MW to 85,800 MW. PJM average day-ahead demand in the first six months of 2016, including DECs and up to congestion transactions, decreased by 5.3 percent from the first six months of 2015, from 94,782 MW to 89,746 MW.

- **Supply and Demand: Load and Spot Market.** Companies that serve load in PJM can do so using a combination of self-supply, bilateral market purchases and spot market purchases. For the first six months of 2016, 8.4 percent of real-time load was supplied by bilateral contracts, 26.8 percent by spot market purchases and 64.8 percent by self-supply. Compared with the first six months of 2015, reliance on bilateral contracts increased by 1.5 percentage points, reliance on spot market purchases decreased by 6.1 percentage points and reliance on self-supply increased by 4.6 percentage points.
- **Supply and Demand: Scarcity.** There were no shortage pricing events in the first six months of 2016.

Market Behavior

- **Offer Capping for Local Market Power.** PJM offer caps units when the local market structure is noncompetitive. Offer capping is an effective means of addressing local market power. Offer capping levels have historically been low in PJM. In the Day-Ahead Energy Market, for units committed to provide energy for local constraint relief, offer-capped unit hours decreased from 0.2 percent in the first six months of 2015 to 0.1 percent in the first six months of 2016. In the Real-Time Energy Market, for units committed to provide energy for local constraint relief, offer-capped unit hours decreased from 0.5 percent in the first six months of 2015 to 0.3 percent in the first six months of 2016.

  In the first six months of 2016, 11 control zones experienced congestion resulting from one or more constraints binding for 50 or more hours. The analysis of the application of the TPS test to local markets demonstrates that it is working successfully to identify pivotal owners when the market structure is noncompetitive and to ensure that owners are not subject to offer capping when the market structure is competitive. There are, however, identified issues with the application of market power mitigation to resources whose owners fail the TPS test that can result in the exercise of local market power. These issues need to be addressed.
- **Offer Capping for Reliability.** PJM also offer caps units that are committed for reliability reasons, specifically for black start service and reactive service. In the Day-Ahead Energy Market, for units committed for reliability reasons, offer-capped unit hours decreased from 0.5 percent in the first six months of 2015 to 0.03 percent in the first six months of 2016. In the Real-Time Energy Market, for units committed for reliability reasons, offer-capped unit hours decreased from 0.6 percent in the first six months of 2015 to 0.03 percent in the first six months of 2016.
- **Markup Index.** The markup index is a summary measure of participant offer behavior for individual marginal units. In the PJM Real-Time Energy Market, when using unadjusted cost offers, in the first six month of 2016, 89.4 percent of marginal units had average dollar markups less than zero and had an average markup index less than zero. Using adjusted cost offers, in the first six months of 2016, 20.0 percent of marginal units had average dollar markups less than zero. Some marginal units did have substantial markups. Among the units that were marginal in the first six months of 2016, none had offer prices above $400 per MWh.

  In the PJM day-ahead energy market, when using unadjusted cost offers, in the first six months of 2016, 62.9 percent of marginal generating units had an average markup index less than or equal to zero. Using adjusted cost offers, in the first six months of 2016, no marginal units had an average markup index less than or equal to zero.
- **Frequently Mitigated Units (FMU) and Associated Units (AU).** A new FMU rule became effective November 1, 2014, limiting the availability of FMU adders to units with net revenues less than unit going forward costs. The number of units that were eligible for an FMU or AU adder declined

from an average of 70 units during the first 11 months of 2014, to zero since December 2014.

- **Virtual Offers and Bids.** Any market participant in the PJM Day-Ahead Energy Market can use increment offers, decrement bids, up to congestion transactions, import transactions and export transactions as financial instruments that do not require physical generation or load. The reduction in up to congestion transactions (UTC) that had followed a FERC order setting September 8, 2014, as the effective date for any uplift charges subsequently assigned to UTCs, was reversed. There was an increase in up to congestion volume as a result of the expiration of the fifteen month refund period for the proceeding related to uplift charges for UTC transactions. In the first six months of 2016, the average hourly up to congestion submitted MW increased by 101.9 percent from 68,947 MW in the first six months of 2015 to 139,199 MW in the first six months of 2016, and cleared MW increased by 98.7 percent from 17,421 MW in the first six months of 2015 to 34,607 MW in the first six months of 2016.

- **Generator Offers.** Generator offers are categorized as dispatchable and self scheduled. Units which are available for economic dispatch are dispatchable. Units which are self scheduled to generate fixed output are categorized as self scheduled. Units which are self scheduled at their economic minimum and are available for economic dispatch up to their economic maximum are categorized as self scheduled and dispatchable. Of all generator offers in the first six months of 2016, 52.5 percent were offered as available for economic dispatch, 22.0 percent were offered as self scheduled, and 17.9 percent were offered as self scheduled and dispatchable.

Market Performance

- **Prices.** PJM LMPs are a direct measure of market performance. Price level is a good, general indicator of market performance, although the number of factors influencing the overall level of prices means it must be analyzed carefully. Among other things, overall average prices reflect changes in supply and demand, generation fuel mix, the cost of fuel, emission related expenses, markup and local price differences caused by congestion. PJM also may administratively set prices with the creation of a closed loop interface related to demand side resources or reactive power or the application of price setting logic.

  PJM real-time energy market prices decreased in the first six months of 2016 compared to the first six months of 2015. The load-weighted average real-time LMP was 36.0 percent lower in the first six months of 2016 than in the first six months of 2015, $27.09 per MWh versus $42.30 per MWh.

  PJM day-ahead energy market prices decreased in the first six months of 2016 compared to the first six months of 2015. The load-weighted average day-ahead LMP was 36.8 percent lower in the first six months of 2016 than in the first six months of 2015, $27.33 per MWh versus $43.26 per MWh.

- **Components of LMP.** In the PJM Real-Time Energy Market, for the first six months of 2016, 53.0 percent of the load-weighted LMP was the result of coal costs, 21.5 percent was the result of gas costs and 2.17 percent was the result of the cost of emission allowances.

  In the PJM day-ahead energy market for the first six months of 2016, 29.8 percent of the load-weighted LMP was the result of the cost of coal, 22.6 percent was the result of DECs, 13.6 percent was the result of the cost of gas, 14.5 percent was the result of INCs, and 4.4 percent was the result of up to congestion transactions.

- **Markup.** The markup conduct of individual owners and units has an identifiable impact on market prices. Markup is a key indicator of the competitiveness of the energy market.

  In the PJM Real-Time Energy Market in the first six months of 2016, the adjusted markup component of LMP was $0.97 per MWh or 3.6 percent of the PJM real-time, load-weighted average LMP. April had the highest adjusted peak markup component, $3.50 per MWh, or 10.58 percent of the real-time load-weighted average LMP. Using the unadjusted cost offers, the highest markup in the first six months of 2016 was $258.16 per MWh. There were 14 hours in the first six months of 2016 where the positive markup contribution to the PJM system wide, load-weighted, average LMP exceeded $54.54 per MWh.

In the PJM Day-Ahead Energy Market, marginal INCs, DECs and UTCs have zero markups. In the first six months of 2016, the adjusted markup component of LMP resulting from generation resources was $1.29 per MWh or 4.7 percent of the PJM day-ahead load-weighted average LMP. January had the highest adjusted markup component, $2.26 per MWh or 7.3 percent of the day-ahead load-weighted average LMP.

Participant behavior was evaluated as competitive because the analysis of markup shows that marginal units generally make offers at, or close to, their marginal costs in both the Day-Ahead and Real-Time Energy Markets, although the behavior of some participants during the high demand periods in the first three months is consistent with economic withholding.

- **Price Convergence.** Hourly and daily price differences between the Day-Ahead and Real-Time Energy Markets fluctuate continuously and substantially from positive to negative. The difference between the average day-ahead and real-time prices was -$1.17 per MWh in the first six months of 2015 and -$0.39 per MWh in the first six months of 2016. The difference between average day-ahead and real-time prices, by itself, is not a measure of the competitiveness or effectiveness of the Day-Ahead Energy Market.

Scarcity

- There were no shortage pricing events in the first six months of 2016.

Recommendations

- The MMU recommends that PJM retain the $1,000 per MWh offer cap in the PJM Energy Market except when cost-based offers exceed $1,000 per MWh, and retain other existing rules that limit incentives to exercise market power. (Priority: High. First reported 1999. Status: Partially adopted, 1999.)
- The MMU recommends that the rules governing the application of the TPS test be clarified and documented. (Priority: High. First reported 2010. Status: Not adopted.)
- The MMU recommends, in order to ensure effective market power mitigation when the TPS test is failed, that markup be constant across price and cost offers, that there be at least one cost-based offer using the same fuel as the available price-based offer. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that in order to ensure effective market power mitigation when the TPS test is failed, the operating parameters in the cost-based offer and the price-based parameter limited schedule (PLS) offer be at least as flexible as the operating parameters in the available non-PLS price-based offer, and that the price-MW pairs in the price based PLS offer be exactly equal to the price-based non-PLS offer. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM require all generating units to identify the fuel type associated with each of their offered schedules. (Priority: Low. First reported 2014. Status: Adopted in full, Q4, 2014.)
- The MMU recommends that under the capacity performance construct, PJM recognize the difference between operational parameters that indicate to PJM dispatchers what a unit is capable of during the operating day and the parameters that are used for capacity performance assessment as well as uplift payments. The parameters which determine nonperformance charges and the amount of uplift payments to those generators should reflect the flexibility goals of the capacity performance construct. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that capacity performance resources and base capacity resources (during the June through September period) be held to the OEM operating parameters of the capacity market CONE reference resource for performance assessment and energy uplift payments. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM remove nonspecific fuel types such as “other” or “co-fire other” from the list of fuel types available for market

participants to identify the fuel type associated with their price and cost schedules. (Priority: Medium. First reported 2015. Status: Not adopted.)

- The MMU recommends that a unit which is not capable of supplying energy consistent with its day-ahead offer should reflect an appropriate outage rather than indicating its availability to supply energy on an emergency basis. (Priority: Low. First reported 2009. Status: Not Adopted.)
- The MMU recommends that PJM explain how LMPs are calculated when demand response is marginal. The LMPs in excess of $1,800 per MWh on January 7, 2014, were potentially a result of the way in which PJM modeled zonal (not nodal) demand response as a marginal resource. (Priority: Low. First reported 2014. Status: Not Adopted.)
- The MMU recommends that PJM explicitly state its policy on the use of transmission penalty factors including the level of the penalty factors, the triggers for the use of the penalty factors, the appropriate line ratings to trigger the use of penalty factors, and when the transmission penalty factors will be used to set the shadow price. (Priority: Medium. First reported 2015.Status: Not adopted.)
- The MMU recommends that PJM explicitly state its policy on the use of constraint relaxation logic and price setting logic. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that PJM routinely review all transmission facility ratings and any changes to those ratings to ensure that the normal, emergency and load dump ratings used in modeling the transmission system are accurate and reflect standard ratings practice. (Priority: Low. First reported 2013. Status: Partially adopted.)
- The MMU recommends that the definition of maximum emergency status in the tariff apply at all times rather than just during maximum emergency events.[4] (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM update the outage impact studies, the reliability analyses used in RPM for capacity deliverability and the reliability analyses used in RTEP for transmission upgrades to be consistent with the more conservative emergency operations (post contingency load dump limit exceedance analysis) in the energy market that were implemented in June 2013. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that the roles of PJM and the transmission owners in the decision making process to control for local contingencies be clarified, that PJM's role be strengthened and that the process be made transparent. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM include in the appropriate manual an explanation of the initial creation of hubs, the process for modifying hub definitions and a description of how hub definitions have changed.[5] There is currently no PJM documentation in the tariff or manuals explaining how hubs are created and how their definitions are changed.[6] (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that during hours when a generation bus shows a net withdrawal, the energy withdrawal be treated as load, not negative generation, for purposes of calculating load and load-weighted LMP. The MMU recommends that during hours when a load bus shows a net injection, the energy injection be treated as generation, not negative load, for purposes of calculating generation and load-weighted LMP. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM identify and collect data on available behind the meter generation resources, including nodal location information and relevant operating parameters. (Priority: Low. First reported 2013. Status: Partially adopted.)
- The MMU recommends that PJM continue to enhance its posting of market data to promote market efficiency. (Priority: Medium. First reported 2005. Status: Partially Adopted.)
- The MMU recommends the elimination of FMU and AU adders. FMU and AU adders no longer serve the purpose for which they were created and interfere with the efficient operation of PJM markets. (Priority: Medium. First reported 2012. Status: Adopted partially, Q4, 2014.)

4 PJM. OATT Section: 6A.1.3 Maximum Emergency, (February 25, 2014), p. 1740, 1795.

5 According to minutes from the first meeting of the Energy Market Committee (EMC) on January 28, 1998, the EMC unanimously agreed to be responsible for approving additions, deletions and changes to the hub definitions to be published and modeled by PJM. Since the EMC has become the Market Implementation Committee (MIC), the MIC now appears to be responsible for such changes.

6 The general definition of a hub can be found in PJM. "Manual 35: Definitions and Acronyms," Revision 23 (April 11, 2014).

Conclusion

The MMU analyzed key elements of PJM energy market structure, participant conduct and market performance in the first six months of 2016, including aggregate supply and demand, concentration ratios, three pivotal supplier test results, offer capping, participation in demand response programs, loads and prices.

Average PJM real-time generation decreased by 3,762 MW, 4.2 percent, and peak load decreased by 8,157 MW, 5.7 percent, in the first six months of 2016 compared to the first six months of 2015. Market concentration levels remained moderate although there is high concentration in the peaking segment of the supply curve which adds to concerns about market power when market conditions are tight. The relationship between supply and demand, regardless of the specific market, balanced by market concentration and the extent of pivotal suppliers, is referred to as the supply-demand fundamentals or economic fundamentals. While the market structure does not guarantee competitive outcomes, overall the market structure of the PJM aggregate energy market remains reasonably competitive for most hours although aggregate market power does exist during high demand hours. Low average aggregate concentration does not mean that market power cannot be exercised. It is possible that market power can be exercised at times when individual suppliers or small groups of suppliers are pivotal even when the average HHI is unconcentrated.

Prices are a key outcome of markets. Prices vary across hours, days and years for multiple reasons. Price is an indicator of the level of competition in a market although individual prices are not always easy to interpret. In a competitive market, prices are directly related to the marginal cost of the most expensive unit required to serve load in each hour. The pattern of prices within days and across months and years illustrates how prices are directly related to supply and demand conditions and thus also illustrates the potential significance of the impact of the price elasticity of demand on prices. Energy market results in the first six months of 2016 generally reflected supply-demand fundamentals, although the behavior of some participants during high demand periods is consistent with economic withholding. Economic withholding is the ability to increase markups substantially in tight market conditions. There are additional issues in the energy market including the uncertainties about the pricing and availability of natural gas, the way that generation owners incorporate natural gas costs in offers, and the lack of adequate incentives for unit owners to take all necessary actions to acquire fuel and operate rather than take an outage.

The three pivotal supplier test is applied by PJM on an ongoing basis for local energy markets in order to determine whether offer capping is required for transmission constraints.[7] This is a flexible, targeted real-time measure of market structure which replaced the offer capping of all units required to relieve a constraint. A generation owner or group of generation owners is pivotal for a local market if the output of the owners' generation facilities is required in order to relieve a transmission constraint. When a generation owner or group of owners is pivotal, it has the ability to increase the market price above the competitive level. The three pivotal supplier test explicitly incorporates the impact of excess supply and implicitly accounts for the impact of the price elasticity of demand in the market power tests. The result of the introduction of the three pivotal supplier test was to limit offer capping to times when the local market structure was noncompetitive and specific owners had structural market power. The analysis of the application of the three pivotal supplier test demonstrates that it is working for most hours to exempt owners when the local market structure is competitive and to require offer capping of owners when the local market structure is noncompetitive.

However, there are some issues with the application of mitigation in the Day-Ahead Energy Market and the Real-Time Energy Market when market sellers fail the TPS test. There is no tariff or manual language that defines in detail the application of the TPS test and offer capping in the Day-Ahead Energy Market and the Real-Time Energy Market. In both the Day-Ahead and Real-Time Energy Markets, generators have the ability to avoid mitigation by using varying markups in their price-based offers, offering different operating parameters in their price-based and cost-based offers, and using different

7 The MMU reviews PJM's application of the TPS test and brings issues to the attention of PJM.

fuels in their price-based and cost-based offers. These issues can be resolved by simple rule changes requiring that markup be constant across price and cost offers, that there be at least one cost-based offer using the same fuel as the available price-based offer, that the price-MW pairs in the price based PLS offer be exactly equal to the price-based non-PLS offer, and requiring cost-based and price-based PLS offers to be at least as flexible as price-based non-PLS offers.

PJM also offer caps units that are committed for reliability reasons in addition to units committed to provide constraint relief. Specifically, units that are committed to provide reactive support and black start service are offer capped in the energy market. These units are committed manually in both the Day-Ahead and Real-Time Energy Markets.

With or without a capacity market, energy market design must permit scarcity pricing when such pricing is consistent with market conditions and constrained by reasonable rules to ensure that market power is not exercised. Scarcity pricing can serve two functions in wholesale power markets: revenue adequacy and price signals. Scarcity pricing for revenue adequacy is not required in PJM. Scarcity pricing for price signals that reflect market conditions during periods of scarcity is required in PJM. Scarcity pricing is also part of an appropriate incentive structure facing both load and generation owners in a working wholesale electric power market design. Scarcity pricing must be designed to ensure that market prices reflect actual market conditions, that scarcity pricing occurs with transparent triggers based on measured reserve levels and transparent prices and that there are strong incentives for competitive behavior and strong disincentives to exercise market power. Such administrative scarcity pricing is a key link between energy and capacity markets. The PJM Capacity Market is explicitly designed to provide revenue adequacy and the resultant reliability. Nonetheless, with a market design that includes a direct and explicit scarcity pricing net revenue true up mechanism, scarcity pricing can be a mechanism to appropriately increase reliance on the energy market as a source of revenues and incentives in a competitive market without reliance on the exercise of market power. PJM implemented scarcity pricing rules in 2012. There are significant issues with the scarcity pricing net revenue true up mechanism in the PJM scarcity pricing design, which will create issues when scarcity pricing occurs. There are also significant issues with PJM's scarcity pricing rules, including the absence of a clear trigger based on measured reserve levels (the current triggers are based on estimated reserves) and the lack of adequate locational scarcity pricing options.

The overall energy market results support the conclusion that energy prices in PJM are set, generally, by marginal units operating at, or close to, their marginal costs, although this was not always the case during the high demand hours in the first six months of 2014, 2015 or 2016. This is evidence of generally competitive behavior and competitive market outcomes, although the behavior of some participants during the high demand periods is consistent with economic withholding. Given the structure of the energy market which can permit the exercise of aggregate market power at times of high demand, the tighter market conditions and the change in some participants' behavior are sources of concern in the energy market and provide a reason to use cost as the sole basis for hourly changes in offers or offers greater than $1,000 per MWh. The MMU concludes that the PJM energy market results were competitive in the first six months of 2016.

Market Structure

Market Concentration

Analysis of supply curve segments of the PJM energy market in the first six months of 2016 indicates moderate concentration in the base load and intermediate segments, but high concentration in the peaking segment.[8] High concentration levels, particularly in the peaking segment, increase the probability that a generation owner will be pivotal in the aggregate market during high demand periods.

When transmission constraints exist, local markets are created with ownership that is typically significantly more concentrated than the overall energy market. PJM offer capping rules that limit the exercise of local market power

8 A unit is classified as base load if it runs for more than 50 percent of hours in the six month period, as intermediate if it runs for less than 50 percent but greater than 10 percent of hours in the six month period, and as peak if it runs for less than 10 percent of hours in the six month period.

were generally effective in preventing the exercise of market power in the first six months of 2016, although there are issues with the application of market power mitigation for resources whose owners fail the TPS test.

The concentration ratio used here is the Herfindahl-Hirschman Index (HHI), calculated by summing the squares of the market shares of all firms in a market. Hourly PJM energy market HHIs were calculated based on the real-time energy output of generators, adjusted for hourly net imports by owner (Table 3-2).

The HHI may not accurately capture market power issues in situations where, for example, there is moderate concentration in all on line resources but there is a high level of concentration in resources needed to meet increases in load. The HHIs for supply curve segments is an indication of such issues. An aggregate pivotal supplier test is required to accurately measure the ability of incremental resources to exercise market power when load is high, for example.

Hourly HHIs were also calculated for baseload, intermediate and peaking segments of generation supply. Hourly energy market HHIs by supply curve segment were calculated based on hourly energy market shares, unadjusted for imports.

The "Merger Policy Statement" of the FERC states that a market can be broadly characterized as:

- **Unconcentrated.** Market HHI below 1000, equivalent to 10 firms with equal market shares;
- **Moderately Concentrated.** Market HHI between 1000 and 1800; and
- **Highly Concentrated.** Market HHI greater than 1800, equivalent to between five and six firms with equal market shares.[9]

PJM HHI Results

Calculations for hourly HHI indicate that by the FERC standards, the PJM Energy Market during the first six months of 2016 was moderately concentrated (Table 3-2).

Table 3-2 PJM hourly energy market HHI: January through June, 2015 and 2016[10]

	Hourly Market HHI (Jan - Jun, 2015)	Hourly Market HHI (Jan - Jun, 2016)
Average	1117	1073
Minimum	916	837
Maximum	1468	1356
Highest market share (One hour)	30%	28%
Average of the highest hourly market share	21%	20%
# Hours	4,343	4,367
# Hours HHI > 1800	0	0
% Hours HHI > 1800	0%	0%

Table 3-3 includes HHI values by supply curve segment, including base, intermediate and peaking plants for the first six months of 2015 and 2016. The PJM Energy Market was moderately concentrated overall with moderate concentration in the baseload and intermediate segments, but high concentration in the peaking segments.

Table 3-3 PJM hourly energy market HHI (By supply segment): January through June, 2015 and 2016

	Jan - Jun, 2015			Jan - Jun, 2016		
	Minimum	Average	Maximum	Minimum	Average	Maximum
Base	1021	1148	1489	984	1157	1443
Intermediate	693	2016	8147	630	1580	6328
Peak	802	6080	10000	687	5821	10000

Figure 3-1 shows the number of units in the baseload, intermediate and peaking segments by fuel source in the first six months of 2016.

9 77 FERC ¶ 61,263, pp. 64-70 (1996), "*Inquiry Concerning the Commission's Merger Policy under the Federal Power Act: Policy Statement.*"

10 This analysis includes all hours in the first six months of 2015 and 2016, regardless of congestion.

Figure 3-1 Fuel source distribution in unit segments: January through June, 2016[11]

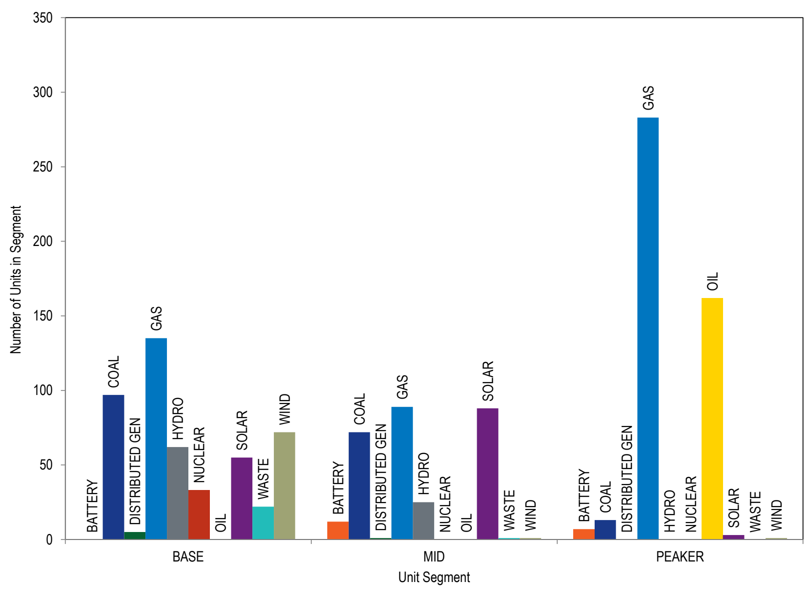
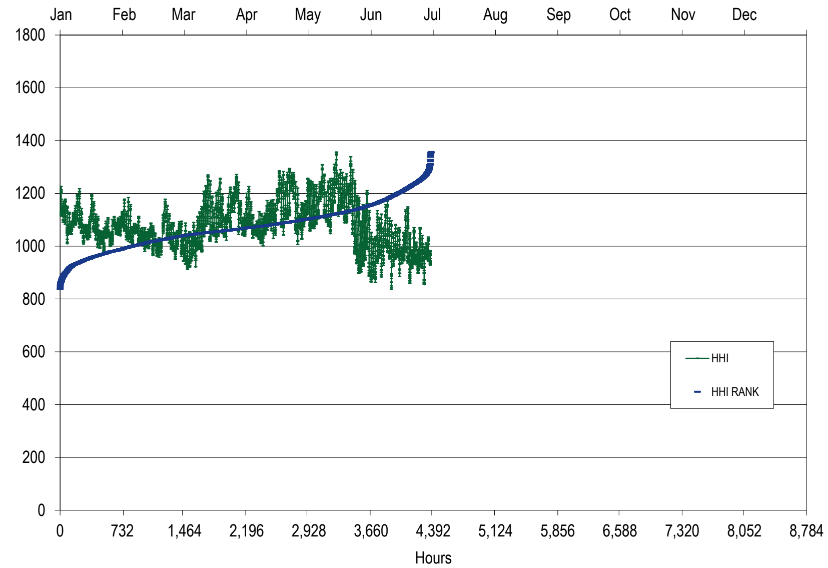


Figure 3-2 presents the hourly HHI values in chronological order and an HHI duration curve for the first six months of 2016.

Figure 3-2 PJM hourly energy market HHI: January through June, 2016



Ownership of Marginal Resources

Table 3-4 shows the contribution to real-time, load-weighted LMP by individual marginal resource owner.[12] The contribution of each marginal resource to price at each load bus is calculated for each five-minute interval of 2016, and summed by the parent company that offers the marginal resource into the Real-Time Energy Market. In the first six months of 2016, the offers of one company resulted in 24.6 percent of the real-time, load-weighted PJM system LMP and that the offers of the top four companies resulted in 61.2 percent of the real-time, load-weighted, average PJM system LMP. During the first six months of 2015, the offers of one company resulted in 17.9 percent

11 The units classified as Distributed Gen are buses within Electric Distribution Companies (EDCs) that are modeled as generation buses to accurately reflect net energy injections from distribution level load buses. The modeling change was the outcome of the Net Energy Metering Task Force stakeholder group in July, 2012. See PJM. "Net Energy Metering Senior Task Force (NEMSTF) Action on Proposed Manual 28 Revisions," (July 26, 2012) <http://www.pjm.com/~/media/committees-groups/committees/mrc/20120726/20120726-item-04-nemstf-report-and-proposed-manual-revisions.ashx>.

12 See the *MMU Technical Reference for PJM Markets*, at "Calculation and Use of Generator Sensitivity/Unit Participation Factors."

of the real time, load-weighted PJM system LMP and offers of the top four companies resulted in 55.0 percent of the real-time, load-weighted, average PJM system LMP. In the first six months of 2016, the offers of one company resulted in 25.7 percent of the peak hour real-time, load weighted PJM system LMP. In the first six months of 2015, the offers of one company resulted in 15.3 percent of the peak hour, real-time, load weighted PJM system LMP.

Table 3-4 Marginal unit contribution to PJM real-time, load-weighted LMP (By parent company): January through June, 2015 and 2016

2015 (Jan-Jun)				2016 (Jan-Jun)			
All Hours		Peak Hours		All Hours		Peak Hours	
Company	Percent of Price	Company	Percent of Price	Company	Percent of Price	Company	Percent of Price
1	17.9%	1	15.3%	1	24.6%	1	25.7%
2	15.6%	2	14.2%	2	15.8%	2	17.6%
3	11.5%	3	10.5%	3	11.3%	3	9.8%
4	10.0%	4	10.3%	4	9.6%	4	9.2%
5	8.4%	5	9.8%	5	8.0%	5	6.6%
6	8.2%	6	9.6%	6	6.7%	6	6.2%
7	5.3%	7	6.1%	7	2.4%	7	2.5%
8	4.6%	8	4.2%	8	2.3%	8	2.4%
9	2.8%	9	3.0%	9	2.3%	9	2.4%
Other (54 companies)	15.6%	Other (48 companies)	17.1%	Other (66 companies)	17.2%	Other (58 companies)	17.8%

Table 3-5 Marginal resource contribution to PJM day-ahead, load-weighted LMP (By parent company): January through June, 2015 and 2016

2015 (Jan - Jun)				2016 (Jan - Jun)			
All Hours		Peak Hours		All Hours		Peak Hours	
Company	Percent of Price	Company	Percent of Price	Company	Percent of Price	Company	Percent of Price
1	12.0%	1	11.5%	1	16.1%	1	14.8%
2	11.8%	2	10.1%	2	8.6%	2	9.3%
3	8.7%	3	8.6%	3	8.4%	3	9.0%
4	6.5%	4	7.4%	4	7.6%	4	7.9%
5	5.9%	5	7.0%	5	7.1%	5	7.2%
6	5.6%	6	5.7%	6	4.6%	6	4.9%
7	5.1%	7	4.6%	7	4.6%	7	3.5%
8	4.2%	8	4.4%	8	4.0%	8	2.9%
9	3.8%	9	4.0%	9	3.6%	9	2.7%
Other (132 companies)	36.3%	Other (128 companies)	36.9%	Other (149 companies)	35.4%	Other (142 companies)	37.9%

Table 3-5 shows the contribution to day-ahead, load-weighted LMP by individual marginal resource owners.[13] The contribution of each marginal resource to price at each load bus is calculated hourly, and summed by the parent company that offers the marginal resource into the Day-Ahead Energy Market. The results show that in the first six months of 2016, the offers of one company contributed 16.1 percent of the day-ahead, load-weighted PJM system LMP and that the offers of the top four companies contributed 40.7 percent of the day-ahead, load-weighted, average PJM system LMP. In the first six months of 2015, the offers of one company contributed 12.0 percent of the day-ahead, load-weighted PJM system LMP and offers of the top four companies contributed 39.0 percent of the day-ahead, load-weighted, average PJM system LMP.

Type of Marginal Resources

LMPs result from the operation of a market based on security-constrained, least-cost dispatch in which marginal resources determine system LMPs, based on their offers. Marginal resource designation is not limited to physical resources in the Day-Ahead Energy Market. INC offers, DEC bids and up to congestion transactions are dispatchable injections and withdrawals in the Day-Ahead Energy Market that can set price via their offers and bids.

Table 3-6 shows the type of fuel used by marginal resources in the Real-Time Energy Market. There can be more than one marginal resource in any given interval as a result of transmission constraints. In the first six months of 2016, coal units were 44.39 percent and natural gas units were 43.38 percent of marginal resources. In the first six months of 2015, coal units were 32.85 percent and natural gas units were 56.12 percent

13 See the *MMU Technical Reference for PJM Markets*, at "Calculation and Use of Generator Sensitivity/Unit Participation Factors."

of the total marginal resources. In the first six months of 2016, 85.10 percent of the wind marginal units had negative offer prices, 11.92 percent had zero offer prices and 2.98 percent had positive offer prices.

The results reflect the dynamics of an LMP market. When there is a single constraint, there are two marginal units. For example, a significant west to east constraint could be binding with a gas unit marginal in the east and a coal unit marginal in the west. As a result, although the dispatch of natural gas units has increased and gas units set price for more hours as marginal resources in the Real-Time Energy Market, this does not necessarily reduce the proportion of hours in which coal units are marginal.[14]

Table 3-6 Type of fuel used (By real-time marginal units): January through June, 2012 through 2016

	Year (Jan - Jun)				
Type/Fuel	2012	2013	2014	2015	2016
Gas	30.04%	33.26%	42.02%	32.85%	44.39%
Coal	59.41%	57.63%	48.59%	56.12%	43.38%
Oil	4.07%	3.08%	3.64%	7.37%	7.73%
Wind	6.03%	5.86%	5.10%	3.11%	3.37%
Uranium	0.00%	0.02%	0.09%	0.05%	0.97%
Other	0.31%	0.15%	0.42%	0.43%	0.14%
Municipal Waste	0.13%	0.01%	0.05%	0.06%	0.02%
Emergency DR	0.00%	0.00%	0.08%	0.00%	0.00%

Figure 3-3 shows the type of fuel used by marginal resources in the Real-Time Energy Market since 2004. The role of coal as a marginal resource has declined while the role of gas as a marginal resource has increased.

Figure 3-3 Type of fuel used (By real-time marginal units): January through June, 2004 through 2016

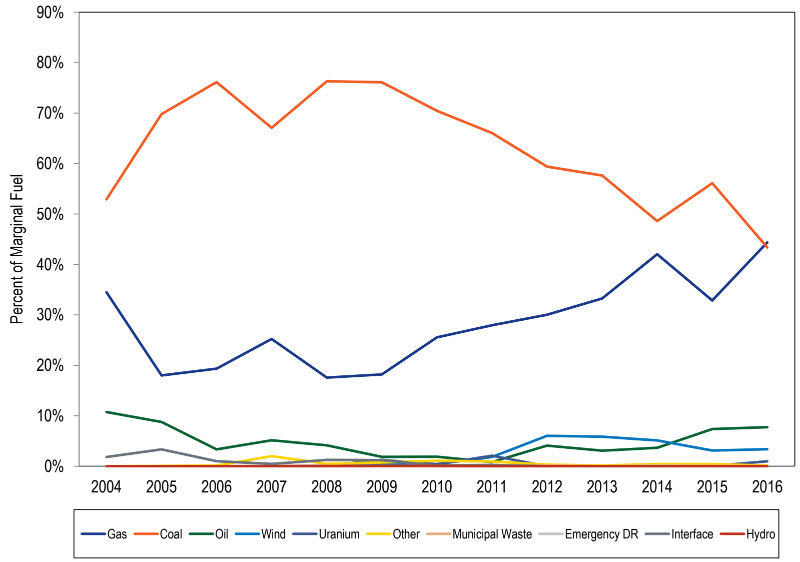


Table 3-7 shows the type and fuel type where relevant, of marginal resources in the Day-Ahead Energy Market. In the first six months of 2016, up to congestion transactions were 83.34 percent of marginal resources. Up to congestion transactions were 74.08 percent of marginal resources in the first six months of 2015.

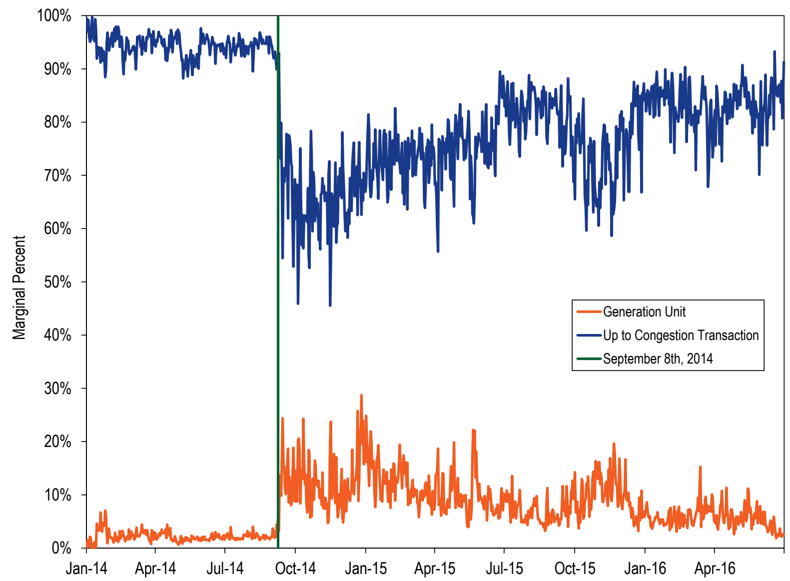
14 Prior to April 1, 2015, for the generation units that are capable of using multiple fuel types, PJM did not require the participants to disclose the fuel type associated with their offer schedule. For these units, the cleared offer schedules on a given day were compared to the cost associated with each fuel to determine the fuel type most likely to have been the basis for the cleared schedule.

Table 3-7 Day-ahead marginal resources by type/fuel: January through June, 2011 through 2016

	(Jan - Jun)					
Type/Fuel	2011	2012	2013	2014	2015	2016
Up to Congestion Transaction	67.39%	86.01%	95.88%	94.25%	74.08%	83.34%
DEC	15.03%	5.26%	1.22%	2.07%	9.11%	7.30%
INC	8.78%	4.97%	0.98%	1.38%	5.35%	3.80%
Gas	2.03%	1.06%	0.54%	0.94%	3.27%	2.42%
Coal	6.06%	2.53%	1.26%	1.20%	7.14%	2.38%
Oil	0.00%	0.00%	0.00%	0.02%	0.42%	0.57%
Dispatchable Transaction	0.31%	0.07%	0.07%	0.10%	0.38%	0.06%
Wind	0.09%	0.04%	0.04%	0.03%	0.18%	0.05%
Uranium	0.00%	0.00%	0.00%	0.00%	0.00%	0.04%
Nuclear	0.00%	0.00%	0.00%	0.00%	0.00%	0.02%
Municipal Waste	0.02%	0.00%	0.00%	0.00%	0.01%	0.02%
Total	100.00%	100.00%	99.99%	100.00%	100.00%	100.00%

Figure 3-4 shows, for the Day-Ahead Market from January 1, 2014, through March 31, 2015, the daily proportion of marginal resources that were up to congestion transaction and/or generation units. The percentage of marginal up to congestion transactions decreased significantly beginning on September 8, 2014, as a result of the FERC's UTC uplift refund notice which became effective on that date.[15] The percentage of marginal up to congestion transaction decreased and that of generation units increased. That trend has begun to reverse as a result of the expiration of the fifteen month refund period for the proceeding related to uplift charges for UTC transactions.

Figure 3-4 Day-ahead marginal up to congestion transaction and generation units: 2014 through June of 2016



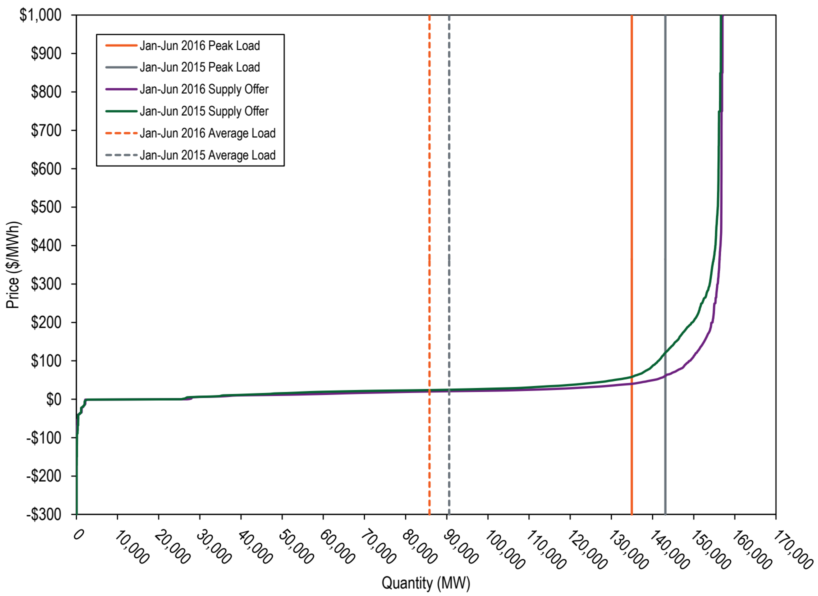
Supply

Supply includes physical generation and imports and virtual transactions.

Figure 3-5 shows the average PJM aggregate real-time generation supply curves by offer price, peak load and average load for the first six months of 2015 and 2016. Total average PJM aggregate real-time generation supply increased by 458 MW, or 0.29 percent, in the first six months of 2016 from 156,679 MW in the first six months of 2015 to 157,137 MW in the first six months of 2016.

15 See 18 CFR § 385.213 (2014).

Figure 3-5 Average PJM aggregate real-time generation supply curves by offer price: January through June, 2015 and 2016



Energy Production by Fuel Source

Table 3-8 shows PJM generation by fuel source in GWh for the first six months of 2015 and the first six months of 2016. In the first six months of 2016, generation from coal units decreased 31.7 percent and generation from natural gas units increased 19.4 percent compared to the first six months of 2015.[16]

Table 3-8 PJM generation (By fuel source (GWh)): January through June, 2015 and 2016[17 18]

Jan-Jun		2015		2016		Change in
		GWh	Percent	GWh	Percent	Output
Coal		147,350.6	37%	122,736.8	32%	(16.7%)
	Standard Coal	29,947.0	8%	2,876.0	1%	(90.4%)
	Waste Coal	708.7	0%	1,441.2	0%	103.4%
	Bituminous	103,534.6	26%	107,212.5	28%	3.6%
	Sub Bituminous	13,160.4	3%	11,207.1	3%	(14.8%)
Nuclear		137,027.2	34%	138,971.3	36%	1.4%
Gas		80,979.5	20%	97,975.7	26%	21.0%
	Natural Gas	79,792.2	20%	97,072.7	25%	21.7%
	Landfill Gas	991.8	0%	903.0	0%	(9.0%)
	Other Gas	195.4	0%	0.1	0%	(100.0%)
Hydroelectric		6,614.0	2%	7,623.1	2%	15.3%
	Pumped Storage	2,044.4	1%	2,119.7	1%	3.7%
	Run of River	3,416.5	1%	4,775.2	1%	39.8%
	Other Hydro	1,153.1	0%	728.2	0%	(36.8%)
Wind		8,790.0	2%	9,650.3	3%	9.8%
Waste		2,061.6	1%	2,056.5	1%	(0.2%)
	Solid Waste	1,991.5	1%	2,056.5	1%	3.3%
	Miscellaneous	70.1	0%	0.0	0%	(100.0%)
Oil		977.1	0%	698.0	0%	(28.6%)
	Heavy Oil	435.2	0%	168.0	0%	(61.4%)
	Light Oil	485.0	0%	200.1	0%	(58.7%)
	Diesel	47.2	0%	32.2	0%	(31.8%)
	Gasoline	0.0	0%	0.0	0%	NA
	Kerosene	9.8	0%	66.9	0%	582.9%
	Jet Oil	0.0	0%	0.0	0%	NA
	Other Oil	0.0	0%	230.9	0%	NA
Solar, Net Energy Metering		255.7	0%	455.5	0%	78.1%
Energy Storage		2.7	0%	8.0	0%	196.7%
	Battery	2.7	0%	8.0	0%	196.7%
	Compressed Air	0.0	0%	0.0	0%	NA
Biofuel		585.2	0%	747.9	0%	27.8%
Geothermal		0.0	0%	0.0	0%	NA
Other Fuel Type		13,636.1	3%	0.0	0%	(100.0%)
Total		398,279.7	100%	380,923.1	100%	(4.4%)

16 Generation data are the sum of MWh for each fuel by source at every generation bus in PJM with positive output and reflect gross generation without offset for station use of any kind.

17 All generation is total gross generation output and does not net out the MWh withdrawn at a generation bus to provide auxiliary/parasitic power or station power, power to synchronous condenser motors, or power to run pumped storage pumps.

18 Net Energy Metering is combined with Solar due to data confidentiality reasons.

Table 3-9 Monthly PJM generation (By fuel source (GWh)): 2016

	Jan	Feb	Mar	Apr	May	Jun	Total
Coal	25,321.1	21,842.9	15,320.7	17,827.5	17,154.1	25,270.6	122,736.8
Standard Coal	487.9	438.8	423.6	257.0	419.9	848.8	2,876.0
Waste Coal	360.3	306.4	203.5	196.3	164.3	210.5	1,441.2
Bituminous	22,106.2	19,373.8	13,695.1	15,464.3	15,444.0	21,129.1	107,212.5
Sub Bituminous	2,366.8	1,723.9	998.4	1,909.9	1,125.9	3,082.2	11,207.1
Nuclear	25,876.0	22,914.1	22,788.2	21,022.7	23,790.7	22,579.5	138,971.3
Gas	16,105.8	15,612.1	17,187.3	13,718.8	14,995.2	20,356.6	97,975.7
Natural Gas	15,948.5	15,464.9	17,033.7	13,568.0	14,850.6	20,207.1	97,072.7
Landfill Gas	157.3	147.2	153.5	150.8	144.6	149.5	903.0
Other Gas	0.0	0.0	0.1	0.0	0.0	0.0	0.1
Hydroelectric	1,453.6	1,400.6	1,274.0	1,067.4	1,251.6	1,176.0	7,623.1
Pumped Storage	357.0	298.6	319.8	298.1	309.8	536.4	2,119.7
Run of River	974.2	1,002.0	849.4	653.4	842.8	453.5	4,775.2
Other Hydro	122.4	100.0	104.8	115.9	98.9	186.1	728.2
Wind	2,095.6	1,925.5	1,781.6	1,588.0	1,230.6	1,029.1	9,650.3
Waste	344.8	297.0	337.5	344.3	366.7	366.0	2,056.5
Solid Waste	344.8	297.0	337.5	344.3	366.7	366.0	2,056.5
Miscellaneous	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil	199.3	139.2	33.1	23.8	104.8	198.0	698.0
Heavy Oil	91.4	45.3	1.0	0.0	0.0	30.3	168.0
Light Oil	88.0	23.2	30.7	22.7	27.7	7.8	200.1
Diesel	11.6	13.6	1.3	0.7	3.3	1.8	32.2
Gasoline	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Kerosene	8.3	57.1	0.0	0.4	0.4	0.6	66.9
Jet Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Oil	0.0	0.0	0.0	0.0	73.3	157.5	230.9
Solar, Net Energy Metering	42.3	47.2	79.5	91.7	83.5	111.3	455.5
Energy Storage	1.3	1.5	1.4	1.4	1.2	1.3	8.0
Battery	1.3	1.5	1.4	1.4	1.2	1.3	8.0
Compressed Air	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biofuel	158.2	144.4	143.2	96.3	76.6	129.2	747.9
Geothermal	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Fuel Type	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	71,598.1	64,324.4	58,946.4	55,781.8	59,054.8	71,217.6	380,923.1

Net Generation and Load

PJM sums all negative (injections) and positive (withdrawals) load at each designated load bus when calculating net load (accounting load). PJM sums all of the negative (withdrawals) and positive (injections) generation at each generation bus when calculating net generation. Netting withdrawals and injections by bus type (generation or load) affects the measurement of total load and total generation. Energy withdrawn at a generation bus to provide, for example, auxiliary/parasitic power or station power, power to synchronous condenser motors, or power to run pumped storage pumps, is actually load, not negative generation. Energy injected at load buses by behind the meter generation is actually generation, not negative load.

The zonal load-weighted LMP is calculated by weighting the zone's load bus LMPs by the zone's load bus accounting load. The definition of injections and withdrawals of energy as generation or load affects PJM's calculation of zonal load-weighted LMP.

The MMU recommends that during hours when a generation bus shows a net withdrawal, the energy withdrawal be treated as load, not negative generation, for purposes of calculating load and load-weighted LMP. The MMU also recommends that during hours when a load bus shows a net injection, the energy injection be treated as generation, not negative load, for purposes of calculating generation and load-weighted LMP.

Real-Time Supply

Average offered real-time generation increased by 458 MW, or 0.29 percent, in the first six months of 2016 from 156,679 MW in the first six months of 2015 to 157,137 MW in the first six months of 2016.[19]

In the first six months of 2016, 4,634.9 MW of new capacity were added to PJM and 706 MW of generation were retired.

19 Calculated values shown in Section 3, "Energy Market," are based on unrounded, underlying data and may differ from calculations based on the rounded values shown in tables.

PJM average real-time generation in the first six months of 2016 decreased by 9.1 percent from the first six months of 2015, from 90,097 MW to 86,335 MW.[20]

PJM average real-time supply including imports decreased by 11.3 percent in the first six months of 2016 from the first six months of 2015, from 96,626 MW to 91,219 MW.

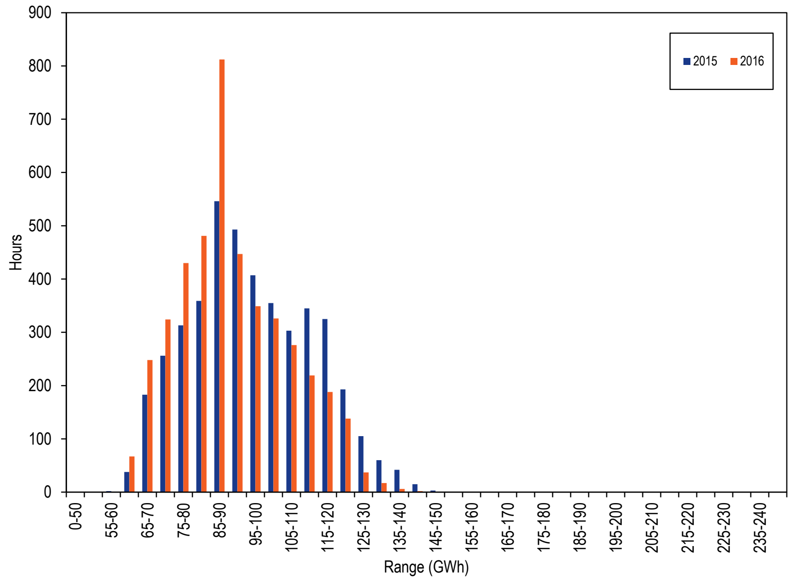
In the PJM Real-Time Energy Market, there are three types of supply offers:

- **Self-Scheduled Generation Offer.** Offer to supply a fixed block of MWh, as a price taker, from a unit that may also have a dispatchable component above the minimum.
- **Dispatchable Generation Offer.** Offer to supply a schedule of MWh and corresponding offer prices from a specific unit.
- **Import.** An import is an external energy transaction scheduled to PJM from another balancing authority. A real-time import must have a valid OASIS reservation when offered, must have available ramp room to support the import, must be accompanied by a NERC Tag, and must pass the neighboring balancing authority checkout process.

PJM Real-Time Supply Duration

Figure 3-6 shows the hourly distribution of PJM real-time generation plus imports for the first six months of 2015 and 2016.

Figure 3-6 Distribution of PJM real-time generation plus imports: January through June, 2015 and 2016[21]



20 Generation data are the net MWh injections and withdrawals MWh at every generation bus in PJM.

21 Each range on the horizontal axis excludes the start value and includes the end value.

PJM Real-Time, Average Supply

Table 3-10 presents summary real-time supply statistics for the first six months of each year for the 17-year period from 2000 through 2016.[22]

Table 3-10 PJM real-time average hourly generation and real-time average hourly generation plus average hourly imports: January through June, 2000 through 2016

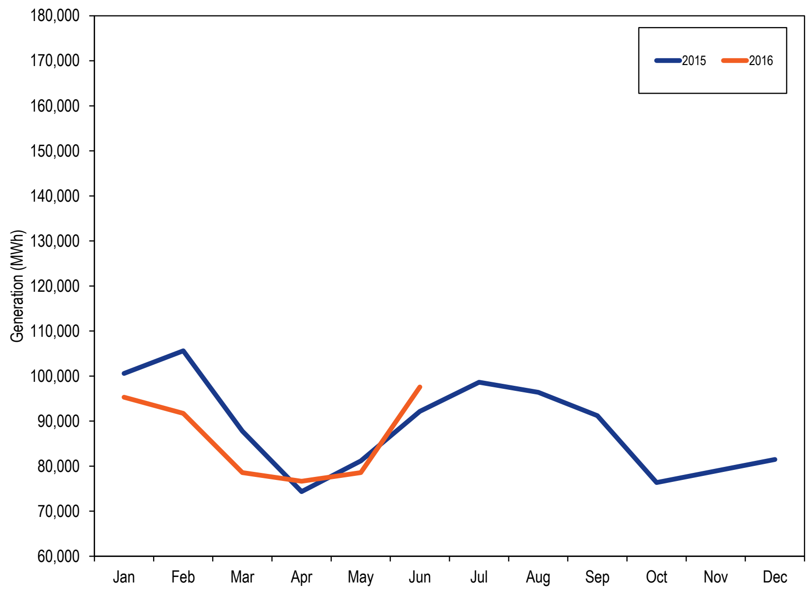
	PJM Real-Time Supply (MWh)				Year-to-Year Change			
	Generation		Generation Plus Imports		Generation		Generation Plus Imports	
Jan-Jun	Generation	Standard Deviation	Supply	Standard Deviation	Generation	Standard Deviation	Supply	Standard Deviation
2000	31,523	5,560	34,190	6,329	NA	NA	NA	NA
2001	29,428	4,679	32,412	4,813	(6.6%)	(15.8%)	(5.2%)	(24.0%)
2002	30,967	5,770	34,730	6,238	5.2%	23.3%	7.2%	29.6%
2003	36,034	6,008	39,644	6,021	16.4%	4.1%	14.1%	(3.5%)
2004	41,430	9,435	45,597	9,699	15.0%	57.0%	15.0%	61.1%
2005	74,365	12,661	79,693	13,242	79.5%	34.2%	74.8%	36.5%
2006	80,249	11,011	84,819	11,574	7.9%	(13.0%)	6.4%	(12.6%)
2007	83,478	12,105	88,150	13,192	4.0%	9.9%	3.9%	14.0%
2008	83,294	12,458	88,824	12,778	(0.2%)	2.9%	0.8%	(3.1%)
2009	77,508	12,961	82,928	13,580	(6.9%)	4.0%	(6.6%)	6.3%
2010	80,702	13,968	85,575	14,455	4.1%	7.8%	3.2%	6.4%
2011	81,483	13,677	86,268	14,428	1.0%	(2.1%)	0.8%	(0.2%)
2012	86,310	13,695	91,526	14,279	5.9%	0.1%	6.1%	(1.0%)
2013	87,974	13,528	93,166	14,277	1.9%	(1.2%)	1.8%	(0.0%)
2014	92,458	15,722	98,186	16,710	5.1%	16.2%	5.4%	17.0%
2015	90,097	16,028	96,626	17,168	(2.6%)	1.9%	(1.6%)	2.7%
2016	86,335	14,576	91,219	15,231	(4.2%)	(9.1%)	(5.6%)	(11.3%)

22 The import data in this table is not available before June 1, 2000. The data that includes imports in 2000 is calculated from the last six months of that year.

PJM Real-Time, Monthly Average Generation

Figure 3-7 compares the real-time, monthly average hourly generation in the first six months of 2016 to 2015.

Figure 3-7 PJM real-time average monthly hourly generation: 2015 through June 2016



Day-Ahead Supply

PJM average day-ahead supply in the first six months of 2016, including INCs and up to congestion transactions, increased by 8.3 percent from the first six months of 2015, from 115,148 MW to 127,748 MW.

PJM average day-ahead supply in the first six months of 2016, including INCs, up to congestion transactions, and imports, increased by 8.2 percent from the first six months of 2015, from 117,612 MW to 129,832 MW. The increase in PJM day-ahead supply was a result of an increase in UTCs beginning in

December 2015 based on a FERC order setting December 8, 2015, as the last effective date for any uplift charges subsequently assigned to UTCs.[23]

In the PJM Day-Ahead Energy Market, there are five types of financially binding supply offers:

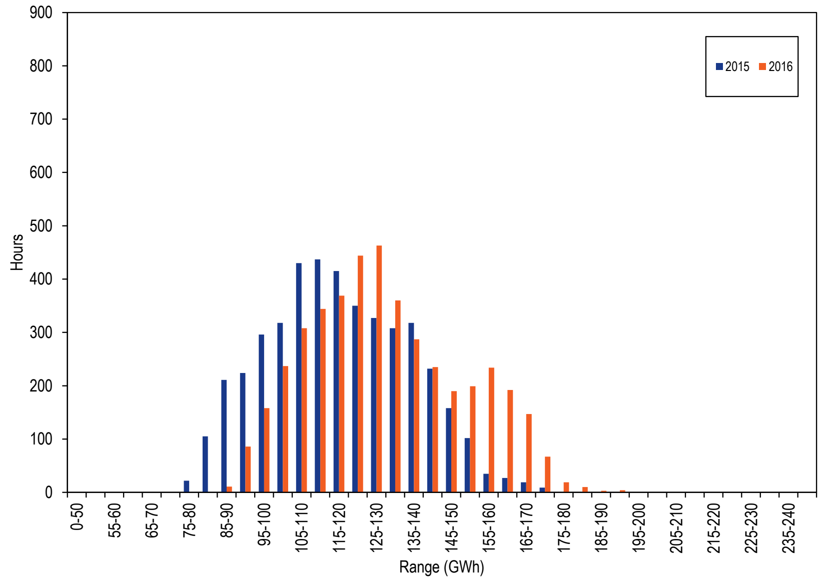
- **Self-Scheduled Generation Offer.** Offer to supply a fixed block of MWh, as a price taker, from a unit that may also have a dispatchable component above the minimum.
- **Dispatchable Generation Offer.** Offer to supply a schedule of MWh and corresponding offer prices from a unit.
- **Increment Offer (INC).** Financial offer to supply MWh and corresponding offer prices. INCs can be submitted by any market participant.
- **Up to Congestion Transaction (UTC).** Conditional transaction that permits a market participant to specify a maximum price spread between the transaction source and sink. An up to congestion transaction is evaluated as a matched pair of an injection and a withdrawal analogous to a matched pair of an INC offer and a DEC bid.
- **Import.** An import is an external energy transaction scheduled to PJM from another balancing authority. An import must have a valid willing to pay congestion (WPC) OASIS reservation when offered. An import energy transaction that clears the Day-Ahead Energy Market is financially binding. There is no link between transactions submitted in the PJM Day-Ahead Energy Market and the PJM Real-Time Energy Market, so an import energy transaction approved in the Day-Ahead Energy Market will not physically flow in real time unless it is also submitted through the real-time energy market scheduling process.

PJM Day-Ahead Supply Duration

Figure 3-8 shows the hourly distribution of PJM day-ahead supply, including increment offers, up to congestion transactions, and imports for the first six months of 2015 and 2016.

23 148 FERC ¶ 61,144 (2014).

Figure 3-8 Distribution of PJM day-ahead supply plus imports: January through June, 2015 and 2016[24]



24 Each range on the horizontal axis excludes the start value and includes the end value.

PJM Day-Ahead, Average Supply

Table 3-11 presents summary day-ahead supply statistics for the first six months of each year of the 17-year period from 2000 through 2016.[25]

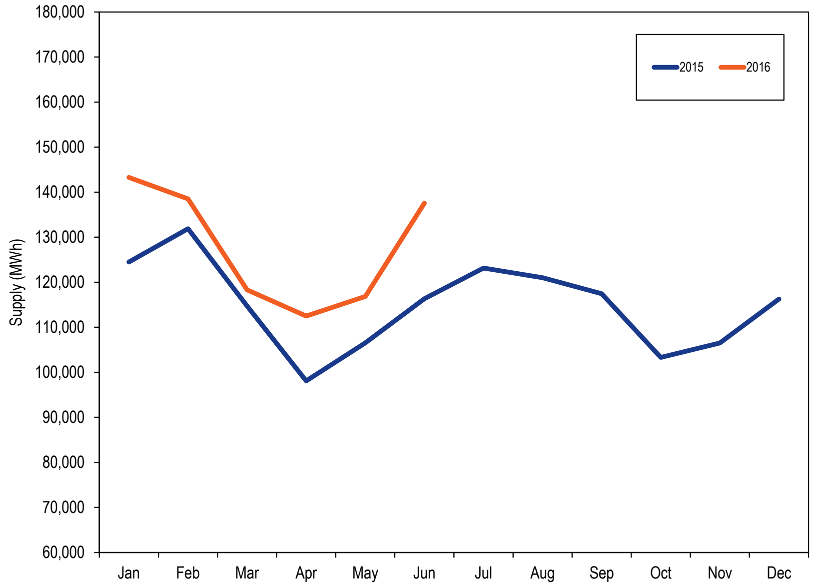
Table 3-11 PJM day-ahead average hourly supply and day-ahead average hourly supply plus average hourly imports: January through June, 2000 through 2016

	PJM Day-Ahead Supply (MWh)				Year-to-Year Change			
	Supply		Supply Plus Imports		Supply		Supply Plus Imports	
Jan-Jun	Supply	Standard Deviation	Supply	Standard Deviation	Supply	Standard Deviation	Supply	Standard Deviation
2000	29,474	5,648	29,645	5,766	NA	NA	NA	NA
2001	26,796	4,305	27,540	4,382	(9.1%)	(23.8%)	(7.1%)	(24.0%)
2002	25,840	10,011	26,398	10,021	(3.6%)	132.5%	(4.1%)	128.7%
2003	36,420	7,000	36,994	7,023	40.9%	(30.1%)	40.1%	(29.9%)
2004	50,089	10,108	50,836	10,171	37.5%	44.4%	37.4%	44.8%
2005	87,855	14,365	89,382	14,395	75.4%	42.1%	75.8%	41.5%
2006	95,562	12,620	97,796	12,615	8.8%	(12.1%)	9.4%	(12.4%)
2007	106,470	14,522	108,815	14,772	11.4%	15.1%	11.3%	17.1%
2008	104,705	14,124	107,169	14,190	(1.7%)	(2.7%)	(1.5%)	(3.9%)
2009	97,607	16,283	100,076	16,342	(6.8%)	15.3%	(6.6%)	15.2%
2010	102,626	18,206	105,463	18,378	5.1%	11.8%	5.4%	12.5%
2011	108,143	16,666	110,656	16,926	5.4%	(8.5%)	4.9%	(7.9%)
2012	132,326	15,710	134,747	15,841	22.4%	(5.7%)	21.8%	(6.4%)
2013	148,381	15,606	150,554	15,830	12.1%	(0.7%)	11.7%	(0.1%)
2014	165,620	13,930	167,939	14,119	11.6%	(10.7%)	11.5%	(10.8%)
2015	115,148	18,849	117,612	18,994	(30.5%)	35.3%	(30.0%)	34.5%
2016	127,748	20,415	129,832	20,554	10.9%	8.3%	10.4%	8.2%

PJM Day-Ahead, Monthly Average Supply

Figure 3-9 compares the day-ahead, monthly average hourly supply, including increment offers and up to congestion transactions, from January 1, 2015, through March 31, 2016.

Figure 3-9 PJM day-ahead monthly average hourly supply: 2015 through June 2016



Real-Time and Day-Ahead Supply

Table 3-12 presents summary statistics for the first six months of 2015 and 2016, for day-ahead and real-time supply. The last two columns of Table 3-12 are the day-ahead supply minus the real-time supply. The first of these columns is the total day-ahead supply less the total real-time supply and the second of these columns is the total physical day-ahead generation less the total physical real-time generation. In the first six months of 2016, up-to congestion transactions were 26.7 percent of the total day-ahead supply compared to 14.8 percent in the first six months of 2015.

25 Since the Day-Ahead Energy Market did not start until June 1, 2000, the day-ahead data for 2000 only includes data for the last six months of that year.

Table 3-12 Day-ahead and real-time supply (MWh): January through June, 2015 and 2016

		Day Ahead					Real Time		Day Ahead Less Real Time	
	Jan-Jun	Generation	INC	Up to Congestion	Imports	Total Supply	Generation	Total Supply	Total Supply	Total Generation
Average	2015	93,011	4,713	17,425	2,464	117,612	90,097	96,626	20,986	2,914
	2016	87,884	5,246	34,615	2,084	129,832	86,335	91,219	38,613	1,549
Median	2015	92,017	4,650	17,190	2,469	116,585	88,510	94,831	21,754	3,507
	2016	85,649	5,108	33,910	2,050	127,289	83,724	88,594	38,695	1,924
Standard Deviation	2015	17,290	694	3,592	426	18,994	16,028	17,168	1,826	1,262
	2016	15,821	1,024	7,097	585	20,554	14,576	15,231	5,323	1,245
Peak Average	2015	101,910	4,863	18,426	2,602	127,801	97,640	104,825	22,976	4,270
	2016	96,366	5,229	36,639	2,151	140,403	93,608	98,917	41,487	2,757
Peak Median	2015	101,652	4,837	18,037	2,613	126,568	96,767	103,701	22,867	4,885
	2016	93,911	5,111	35,778	2,119	136,847	91,296	96,223	40,624	2,615
Peak Standard Deviation	2015	14,167	651	3,604	423	15,794	13,896	14,766	1,027	271
	2016	12,959	951	6,814	670	17,492	12,641	12,982	4,510	318
Off-Peak Average	2015	84,951	4,577	16,518	2,338	108,384	83,265	89,200	19,184	1,685
	2016	80,170	5,260	32,774	2,022	120,218	79,721	84,218	36,000	449
Off-Peak Median	2015	83,297	4,490	16,244	2,306	105,973	81,495	86,632	19,340	1,802
	2016	77,545	5,105	31,677	1,998	116,178	77,265	81,431	34,747	279
Off-Peak Standard Deviation	2015	15,852	704	3,331	388	16,807	14,716	15,755	1,052	1,136
	2016	14,154	1,085	6,845	487	18,288	12,982	13,669	4,619	1,172

Figure 3-10 shows the average hourly cleared volumes of day-ahead supply and real-time supply for 2015. The day-ahead supply consists of day-ahead generation, imports, cleared increment offers and cleared up to congestion transactions. The real-time generation includes generation and imports.

Figure 3-10 Day-ahead and real-time supply (Average hourly volumes): January through June, 2016

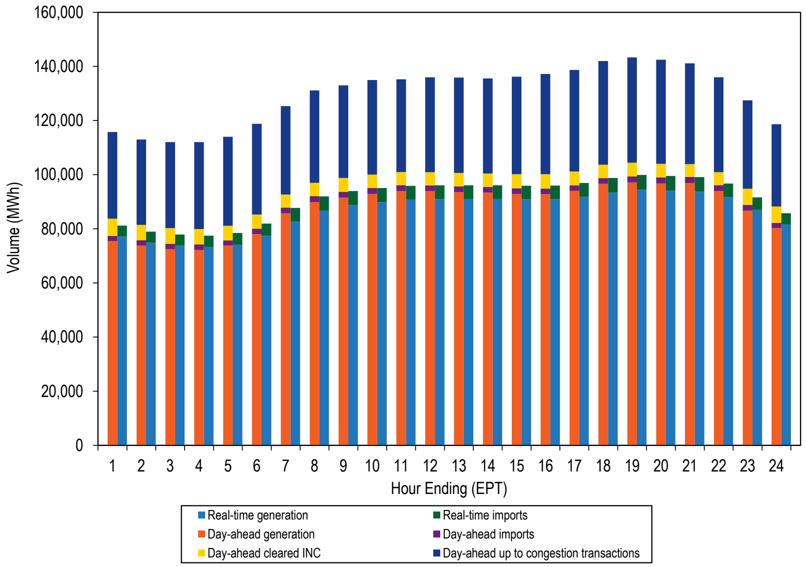


Figure 3-11 Difference between day-ahead and real-time supply (Average daily volumes): 2015 through June 2016

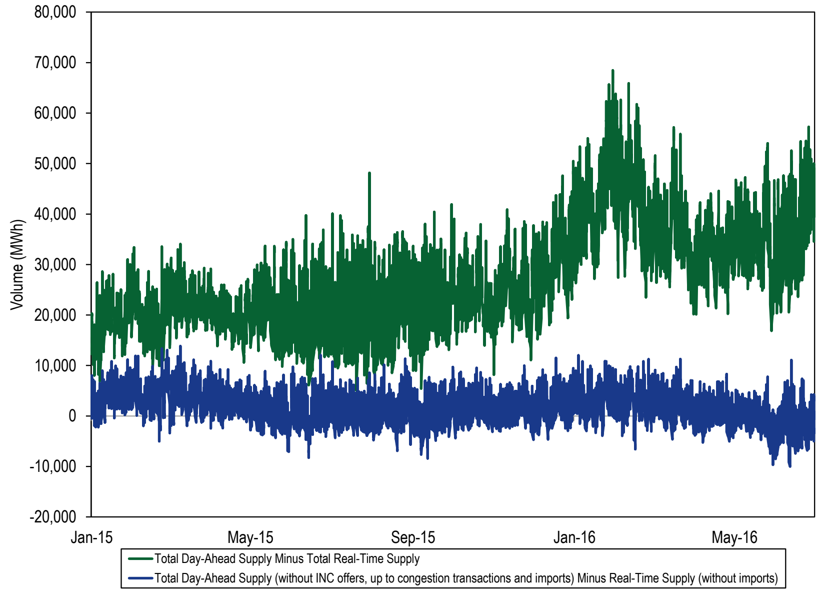
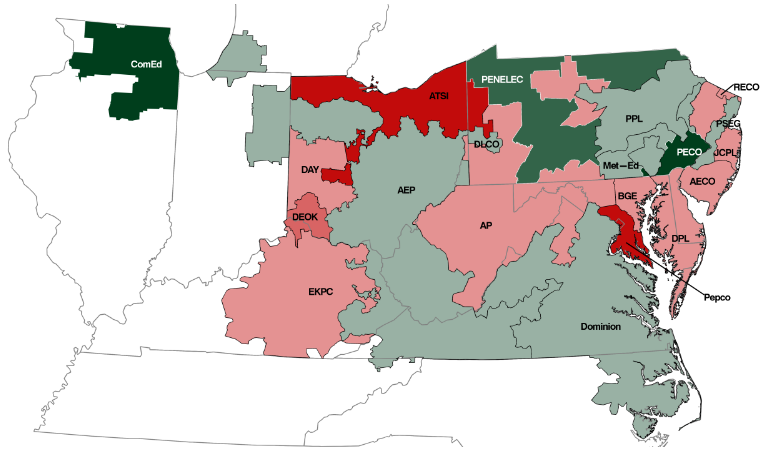


Figure 3-11 shows the difference between the day-ahead and real-time average daily supply for January 1, 2015, through June 30, 2016.

Figure 3-12 shows the difference between the PJM real-time generation and real-time load by zone in the first six months of 2016. Figure 3-12 is color coded on a scale on which red shades represent zones that have less generation than load and green shades represent zones that have more generation than load, with darker shades meaning greater amounts of net generation or load. For example, the Pepco Control Zone has less generation than load, while the PENELEC Control Zone has more generation than load. Table 3-13 shows the difference between the PJM real-time generation and real-time load by zone in the first six months of 2015 and 2016.

Figure 3-12 Map of PJM real-time generation less real-time load by zone: January through June, 2016[26]



Zone	Net Gen Minus Load (GWh)	Zone	Net Gen Minus Load (GWh)	Zone	Net Gen Minus Load (GWh)	Zone	Net Gen Minus Load (GWh)
AECO	(1,436)	ComEd	13,834	DPL	(4,907)	PENELEC	8,215
AEP	3,204	DAY	(1,086)	EKPC	(1,476)	Pepco	(10,084)
AP	(1,382)	DEOK	(6,874)	JCPL	(2,414)	PPL	3,164
ATSI	(12,954)	DLCO	2,130	Met-Ed	3,857	PSEG	2,261
BGE	(4,829)	Dominion	1,171	PECO	12,626	RECO	(682)

Table 3-13 PJM real-time generation less real-time load by zone (GWh): January through June, 2015 and 2016

Zonal Generation and Load (GWh)						
	Jan-Jun 2015			Jan-Jun 2016		
Zone	Generation	Load	Net	Generation	Load	Net
AECO	2,836.0	5,105.9	(2,269.9)	3,136.9	4,573.0	(1,436.1)
AEP	73,030.8	65,187.9	7,842.9	65,477.0	62,273.2	3,203.9
AP	20,898.6	25,170.3	(4,271.7)	22,296.2	23,678.2	(1,382.0)
ATSI	23,158.8	33,769.7	(10,610.9)	19,488.2	32,441.7	(12,953.5)
BGE	11,084.5	16,454.9	(5,370.4)	10,221.5	15,050.8	(4,829.4)
ComEd	62,304.6	46,795.9	15,508.8	60,544.7	46,710.6	13,834.1
DAY	6,356.2	8,533.2	(2,177.1)	7,284.3	8,370.5	(1,086.2)
DEOK	9,437.7	13,491.7	(4,054.0)	6,218.9	13,092.8	(6,873.9)
DLCO	8,295.3	7,095.3	1,200.0	8,746.4	6,616.2	2,130.2
Dominion	43,431.8	49,298.9	(5,867.0)	47,296.2	46,125.6	1,170.5
DPL	3,827.6	9,540.9	(5,713.3)	3,714.4	8,621.3	(4,906.8)
EKPC	4,529.2	6,447.5	(1,918.3)	4,800.6	6,276.4	(1,475.9)
JCPL	6,253.7	11,312.5	(5,058.8)	8,184.9	10,599.1	(2,414.2)
Met-Ed	11,241.4	7,771.3	3,470.1	11,251.5	7,394.6	3,856.9
PECO	29,003.8	20,228.4	8,775.3	31,762.2	19,136.4	12,625.7
PENELEC	21,850.0	8,804.8	13,045.3	16,511.1	8,296.4	8,214.8
Pepco	5,128.6	15,475.1	(10,346.5)	4,339.3	14,422.9	(10,083.6)
PPL	25,840.0	21,079.1	4,760.9	23,058.7	19,894.5	3,164.2
PSEG	22,781.3	21,110.3	1,671.0	22,692.9	20,432.0	2,260.9
RECO	0.0	731.0	(731.0)	0.0	681.8	(681.8)

Demand

Demand includes physical load and exports and virtual transactions.

Peak Demand

In this section, demand refers to physical load and exports and in the Day-Ahead Energy Market also includes virtual transactions.

The PJM system real-time peak load for the first six months of 2016 was 134,958 MW in the HE 17 on June 20, 2016, which was 8,157 MW, or 5.7 percent, lower than the peak load for the first six months of 2015, which was 143,115MW in the HE 8 on February 20, 2015.

Table 3-14 shows the peak loads for the first six months of 1999 through 2016.

26 Zonal real-time generation data for the map and corresponding table is based on the zonal designation for every bus listed in the most current PJM LMP bus model, which can be found at <http://www.pjm.com/markets-and-operations/energy/lmp-model-info.aspx>.

Table 3-14 Actual PJM footprint peak loads: 1999 to 2016[27]

(Jan - Jun)	Date	Hour Ending (EPT)	PJM Load (MW)	Annual Change (MW)	Annual Change (%)
1999	Tue, June 08	17	114,607	NA	NA
2000	Mon, June 26	16	112,028	(2,579)	(2.3%)
2001	Thu, June 28	17	115,808	3,780	3.4%
2002	Mon, June 24	17	122,105	6,297	5.4%
2003	Wed, June 25	17	119,378	(2,727)	(2.2%)
2004	Wed, June 09	17	120,218	840	0.7%
2005	Tue, June 28	16	124,052	3,833	3.2%
2006	Tue, May 30	17	121,165	(2,887)	(2.3%)
2007	Wed, June 27	16	130,971	9,806	8.1%
2008	Mon, June 09	17	130,100	(871)	(0.7%)
2009	Fri, January 16	19	117,169	(12,930)	(9.9%)
2010	Wed, June 23	17	126,188	9,019	7.7%
2011	Wed, June 08	17	144,350	18,162	14.4%
2012	Wed, June 20	18	147,913	3,563	2.5%
2013	Tue, June 25	16	139,779	(8,134)	(5.5%)
2014	Tue, June 17	17	141,673	1,895	1.4%
2015	Fri, February 20	8	143,115	1,441	1.0%
2016	Mon, June 20	17	134,958	(8,157)	(5.7%)

Figure 3-13 shows the peak loads for 1999 through June 2016.

Figure 3-13 PJM footprint calendar year peak loads: 1999 to June 2016

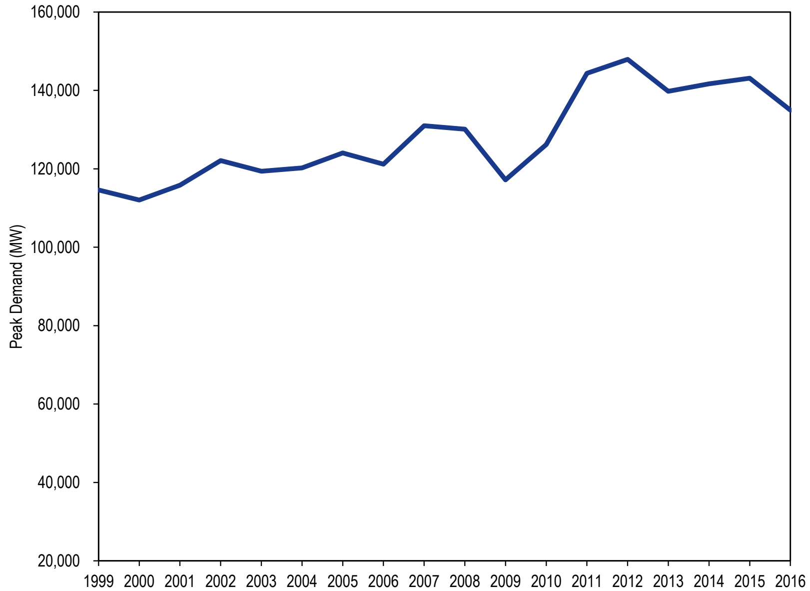
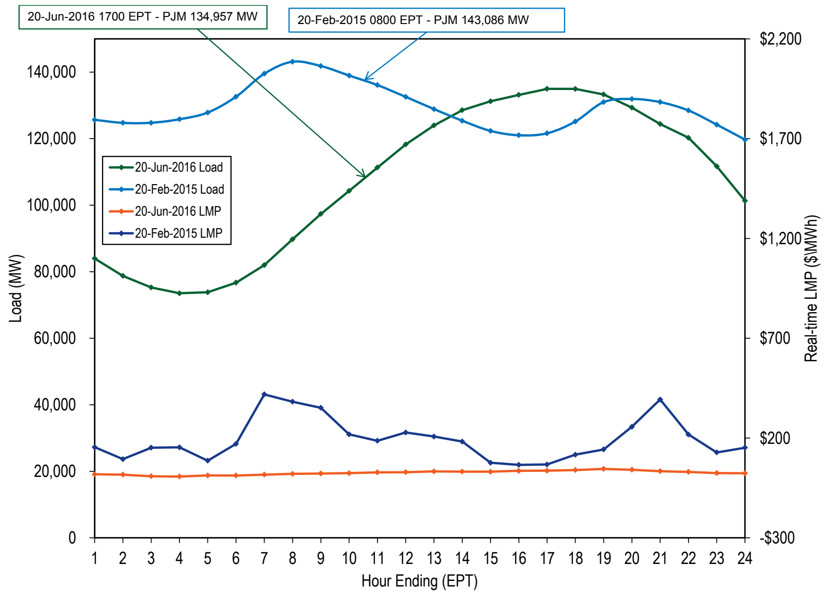


Figure 3-14 compares the peak load days during the first six months of 2015 and 2016. The average hourly real-time LMP peaked at $45.54 on June 20, 2016, and peaked at $418.73 on February 20, 2015.

27 Peak loads shown are eMTR load. See the *MMU Technical Reference for the PJM Markets*, at "Load Definitions" for detailed definitions of load. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

Figure 3-14 PJM peak-load comparison Monday, June 20, 2016 and Friday, February 20, 2015



Real-Time Demand

PJM average real-time load in the first six months of 2016 decreased by 5.3 percent from the first six months of 2015, from 90,586 MW to 85,800 MW.[28]

PJM average real-time demand in the first six months of 2016 decreased 5.3 percent from the first six months of 2015, from 94,782 MW to 89,746 MW.

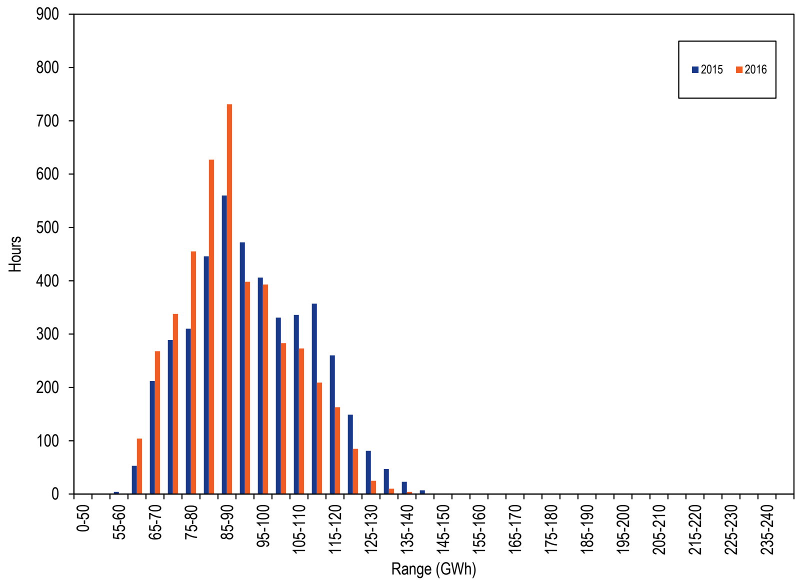
In the PJM Real-Time Energy Market, there are two types of demand:

- **Load.** The actual MWh level of energy used by load within PJM.
- **Export.** An export is an external energy transaction scheduled from PJM to another balancing authority. A real-time export must have a valid OASIS reservation when offered, must have available ramp room to support the export, must be accompanied by a NERC Tag, and must pass the neighboring balancing authority checkout process.

PJM Real-Time Demand Duration

Figure 3-15 shows the hourly distribution of PJM real-time load plus exports for the first six months of 2015 and 2016.[29]

Figure 3-15 Distribution of PJM real-time accounting load plus exports: January through June, 2015 and 2016[30]



28 Load data are the net MWh injections and withdrawals MWh at every load bus in PJM.

29 All real-time load data in Section 3, "Energy Market," "Market Performance: Load and LMP," are based on PJM accounting load. See the *Technical Reference for PJM Markets*, "Load Definitions," for detailed definitions of accounting load. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

30 Each range on the horizontal axis excludes the start value and includes the end value.

PJM Real-Time, Average Load

Table 3-15 presents summary real-time demand statistics for the first six months of 1998 to 2016. Before June 1, 2007, transmission losses were included in accounting load. After June 1, 2007, transmission losses were excluded from accounting load and losses were addressed through marginal loss pricing.[31]

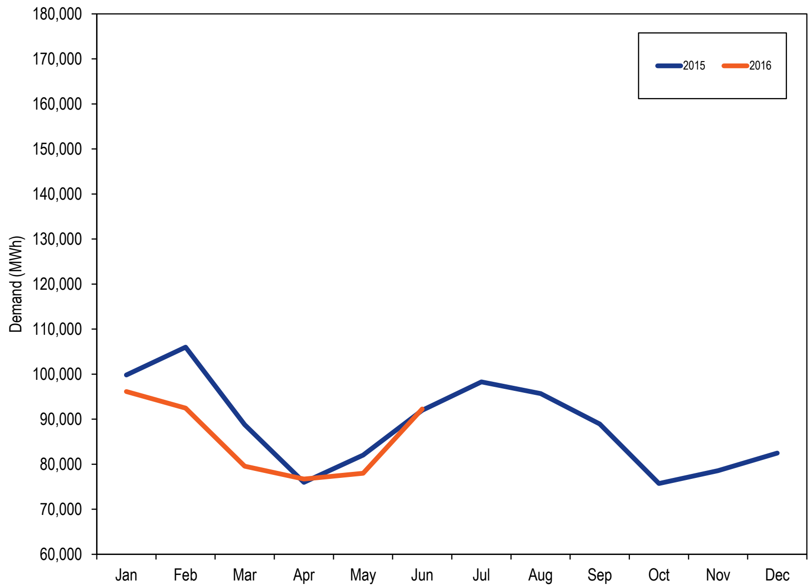
Table 3-15 PJM real-time average hourly load and real-time average hourly load plus average hourly exports: January through June, 1998 through 2016[32]

	PJM Real-Time Demand (MWh)				Year-to-Year Change			
	Load		Load Plus Exports		Load		Load Plus Exports	
Jan-Jun	Load	Standard Deviation	Demand	Standard Deviation	Load	Standard Deviation	Demand	Standard Deviation
1998	27,662	4,703	27,662	4,703	NA	NA	NA	NA
1999	28,714	5,113	28,714	5,113	3.8%	8.7%	3.8%	8.7%
2000	29,649	5,382	29,902	5,511	3.3%	5.3%	4.1%	7.8%
2001	30,180	5,274	32,041	5,103	1.8%	(2.0%)	7.2%	(7.4%)
2002	32,678	6,457	33,969	6,557	8.3%	22.4%	6.0%	28.5%
2003	36,727	6,428	38,775	6,554	12.4%	(0.4%)	14.1%	(0.0%)
2004	41,787	8,999	44,808	10,033	13.8%	40.0%	15.6%	53.1%
2005	71,939	13,603	78,745	13,798	72.2%	51.2%	75.7%	37.5%
2006	77,232	12,003	83,606	12,377	7.4%	(11.8%)	6.2%	(10.3%)
2007	81,110	13,499	86,557	13,819	5.0%	12.5%	3.5%	11.6%
2008	78,685	12,819	85,819	13,242	(3.0%)	(5.0%)	(0.9%)	(4.2%)
2009	75,991	12,899	81,062	13,253	(3.4%)	0.6%	(5.5%)	0.1%
2010	78,106	13,643	83,758	14,227	2.8%	5.8%	3.3%	7.3%
2011	78,823	13,931	84,288	14,046	0.9%	2.1%	0.6%	(1.3%)
2012	84,946	13,941	89,638	13,848	7.8%	0.1%	6.3%	(1.4%)
2013	86,897	13,871	91,199	13,848	2.3%	(0.5%)	1.7%	0.0%
2014	90,529	16,266	96,189	16,147	4.2%	17.3%	5.5%	16.6%
2015	90,586	16,192	94,782	16,589	0.1%	(0.5%)	(1.5%)	2.7%
2016	85,800	14,517	89,746	14,798	(5.3%)	(10.3%)	(5.3%)	(10.8%)

PJM Real-Time, Monthly Average Load

Figure 3-16 compares the real-time, monthly average hourly loads from January 1, 2015, through June 30, 2016.

Figure 3-16 PJM real-time monthly average hourly load: January 2015 through June 2016



PJM real-time load is significantly affected by temperature. Figure 3-17 and Table 3-16 compare the PJM monthly heating and cooling degree days in the first six months of 2015 and 2016.[33] Heating degree days decreased 20.6 percent, and cooling degree days decreased 9.8 percent from the first six months of 2015 to 2016.

31 Accounting load is used here because PJM uses accounting load in the settlement process, which determines how much load customers pay for. In addition, the use of accounting load with losses before June 1, and without losses after June 1, 2007, is consistent with PJM's calculation of LMP, which excludes losses prior to June 1 and includes losses after June 1.

32 Export data are not available before June 1, 2000. The export data for 2000 are for the last six months of 2000.

33 A heating degree day is defined as the number of degrees that a day's average temperature is below 65 degrees F (the temperature below which buildings need to be heated). A cooling degree day is the number of degrees that a day's average temperature is above 65 degrees F (the temperature when people will start to use air conditioning to cool buildings). PJM uses 60 degrees F for a heating degree day as stated in Manual 19.
Heating and cooling degree days are calculated by weighting the temperature at each weather station in the individual transmission zones using weights provided by PJM in Manual 19. Then the temperature is weighted by the real-time zonal accounting load for each transmission zone. After calculating an average hourly temperature across PJM, the heating and cooling degree formulas are used to calculate the daily heating and cooling degree days, which are summed for monthly reporting. The weather stations that provided the basis for the analysis are ABE, ACY, AVP, BWI, CAK, CLE, CMH, CRW, CVG, DAY, DCA, ERI, EWR, FWA, IAD, ILG, IPT, LEX, ORD, ORF, PHL, PIT, RIC, ROA, TOL and WAL.

Figure 3-17 PJM heating and cooling degree days: 2015 and through June 2016

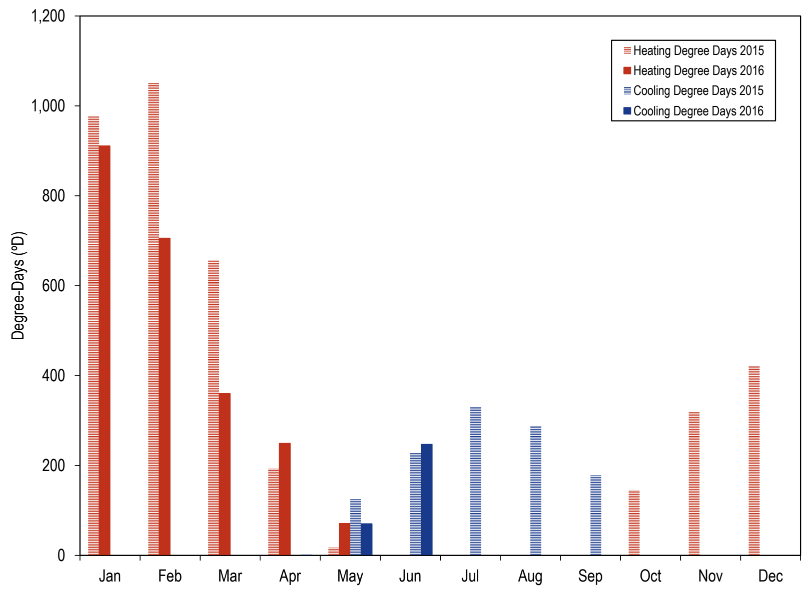


Table 3-16 PJM heating and cooling degree days: 2015 and January through June 2016

	2015		2016		Percent Change	
	Heating Degree Days	Cooling Degree Days	Heating Degree Days	Cooling Degree Days	Heating Degree Days	Cooling Degree Days
Jan	977	0	911	0	(6.7%)	0.0%
Feb	1,051	0	706	0	(32.8%)	0.0%
Mar	656	0	360	0	(45.1%)	0.0%
Apr	193	0	250	1	29.1%	0.0%
May	18	125	71	71	299.6%	(43.7%)
Jun	1	228	0	247	(100%)	8.6%
Jul	0	330	NA	NA	NA	NA
Aug	0	289	NA	NA	NA	NA
Sep	0	179	NA	NA	NA	NA
Oct	145	0	NA	NA	NA	NA
Nov	319	0	NA	NA	NA	NA
Dec	421	0	NA	NA	NA	NA
Total	3,781	1,151	2,298	319	(20.6%)	(72.3%)

Day-Ahead Demand

PJM average day-ahead demand in the first six months of 2016, including DECs and up to congestion transactions, increased by 11.5 percent from the first six months of 2015, from 111,749 MW to 124,576 MW.

PJM average day-ahead demand in the first six months of 2016, including DECs, up to congestion transactions, and exports, increased by 8.4 percent from the first six months of 2015, from 115,294 MW to 127,674 MW.

The reduction in up to congestion transactions (UTC) that had followed a FERC order setting September 8, 2014, as the effective date for any uplift charges subsequently assigned to UTCs, was reversed. There was an increase in up to congestion volume as a result of the expiration of the fifteen month refund period for the proceeding related to uplift charges for UTC transactions.[34]

In the PJM Day-Ahead Energy Market, five types of financially binding demand bids are made and cleared:

- **Fixed-Demand Bid.** Bid to purchase a defined MWh level of energy, regardless of LMP.
- **Price-Sensitive Bid.** Bid to purchase a defined MWh level of energy only up to a specified LMP, above which the load bid is zero.
- **Decrement Bid (DEC).** Financial bid to purchase a defined MWh level of energy up to a specified LMP, above which the bid is zero. A DEC can be submitted by any market participant.
- **Up to Congestion Transaction (UTC).** A conditional transaction that permits a market participant to specify a maximum price spread between the transaction source and sink. An up to congestion transaction is evaluated as a matched pair of an injection and a withdrawal analogous to a matched pair of an INC offer and a DEC bid.
- **Export.** An external energy transaction scheduled from PJM to another balancing authority. An export must have a valid willing to pay congestion (WPC) OASIS reservation when offered. An export energy transaction that clears the Day-Ahead Energy Market is financially binding. There is

34 148 FERC ¶ 61,144 (2014).

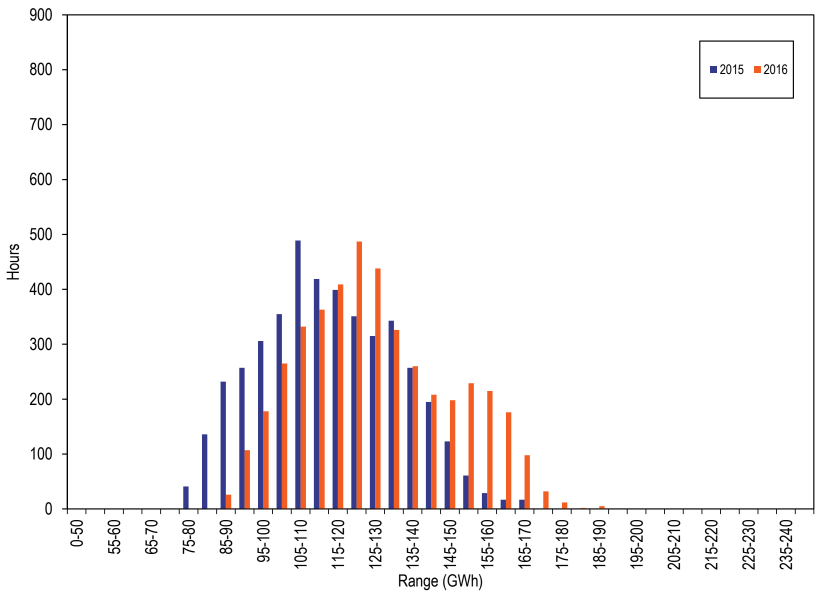
no link between transactions submitted in the PJM Day-Ahead Energy Market and the PJM Real-Time Energy Market, so an export energy transaction approved in the Day-Ahead Energy Market will not physically flow in real time unless it is also submitted through the Real-Time Energy Market scheduling process.

PJM day-ahead demand is the hourly total of the five types of cleared demand bids.

PJM Day-Ahead Demand Duration

Figure 3-18 shows the hourly distribution of PJM day-ahead demand, including decrement bids, up to congestion transactions, and exports for the first six months of 2015 and 2016.

Figure 3-18 Distribution of PJM day-ahead demand plus exports: January through June, 2015 and 2016[35]



35 Each range on the horizontal axis excludes the start value and includes the end value.

PJM Day-Ahead, Average Demand

Table 3-17 presents summary day-ahead demand statistics for the first six months of each year from 2000 to 2016.[36]

Table 3-17 PJM day-ahead average demand and day-ahead average hourly demand plus average hourly exports: January through June, 2000 through 2016

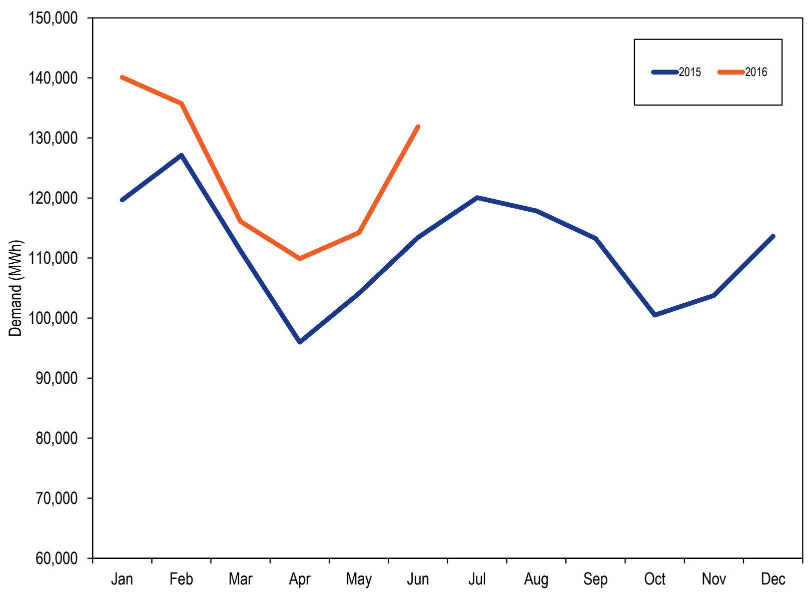
	PJM Day-Ahead Demand (MWh)				Year-to-Year Change			
	Demand		Demand Plus Exports		Demand		Demand Plus Exports	
Jan-Jun	Demand	Standard Deviation	Demand	Standard Deviation	Demand	Standard Deviation	Demand	Standard Deviation
2000	35,448	8,138	35,623	7,982	NA	NA	NA	NA
2001	32,425	6,014	33,075	5,857	(8.5%)	(26.1%)	(7.2%)	(26.6%)
2002	37,561	8,293	37,607	8,311	15.8%	37.9%	13.7%	41.9%
2003	44,391	7,717	44,503	7,704	18.2%	(6.9%)	18.3%	(7.3%)
2004	50,161	10,304	50,596	10,557	13.0%	33.5%	13.7%	37.0%
2005	86,890	14,677	89,388	14,827	73.2%	42.4%	76.7%	40.4%
2006	94,470	12,925	97,460	13,303	8.7%	(11.9%)	9.0%	(10.3%)
2007	104,737	15,019	107,647	15,269	10.9%	16.2%	10.5%	14.8%
2008	100,948	14,255	104,499	14,461	(3.6%)	(5.1%)	(2.9%)	(5.3%)
2009	95,130	15,878	98,001	15,972	(5.8%)	11.4%	(6.2%)	10.4%
2010	99,691	18,097	103,573	18,366	4.8%	14.0%	5.7%	15.0%
2011	105,071	16,452	108,756	16,578	5.4%	(9.1%)	5.0%	(9.7%)
2012	129,881	15,268	133,046	15,436	23.6%	(7.2%)	22.3%	(6.9%)
2013	145,280	15,552	148,414	15,588	11.9%	1.9%	11.6%	1.0%
2014	160,805	13,872	164,740	13,800	10.7%	(10.8%)	11.0%	(11.5%)
2015	111,749	18,074	115,294	18,468	(30.5%)	30.3%	(30.0%)	33.8%
2016	124,576	19,786	127,674	20,027	11.5%	9.5%	10.7%	8.4%

PJM Day-Ahead, Monthly Average Demand

Figure 3-19 compares the day-ahead, monthly average hourly demand, including decrement bids and up to congestion transactions, from January 1, 2015, through June 31, 2016.

36 Since the Day-Ahead Energy Market did not start until June 1, 2000, the day-ahead data for 2000 only includes data for the last six months of that year.

Figure 3-19 PJM day-ahead monthly average hourly demand: January 2015 through June 2016



Real-Time and Day-Ahead Demand

Table 3-18 presents summary statistics for the first six months of 2015 and 2016 day-ahead and real-time demand. The last two columns of Table 3-18 are the day-ahead demand minus the real-time demand. The first such column is the total day-ahead demand less the total real-time demand and the second such column is the total physical day-ahead load (fixed demand plus price-sensitive demand) less the physical real-time load.

Table 3-18 Cleared day-ahead and real-time demand (MWh): January through June, 2015 and 2016

		Day-Ahead						Real-Time		Day-Ahead Less Real-Time	
	Jan-Jun Year	Fixed Demand	Price Sensitive	Dec	Up to Congestion	Exports	Total Demand	Load	Total Demand	Total Demand	Total Load
Average	2015	86,891	3,133	4,300	17,425	3,545	115,294	90,586	94,782	20,512	70,074
	2016	82,536	3,088	4,333	34,615	3,098	127,674	85,800	89,746	37,928	47,872
Median	2015	85,670	3,238	4,079	17,190	3,398	114,177	88,946	93,024	21,153	67,793
	2016	81,050	3,091	4,038	33,910	2,890	125,197	83,572	87,202	37,995	45,577
Standard Deviation	2015	15,378	655	1,279	3,592	1,036	18,468	16,192	16,589	1,878	14,314
	2016	13,649	393	1,310	7,097	931	20,027	14,517	14,798	5,229	9,287
Peak Average	2015	95,165	3,387	4,613	18,426	3,622	125,213	98,598	102,752	22,461	76,137
	2016	90,281	3,323	4,606	36,639	3,115	137,983	93,391	97,241	40,742	52,649
Peak Median	2015	94,032	3,482	4,386	18,037	3,431	123,990	97,538	101,752	22,238	75,301
	2016	88,441	3,292	4,373	35,778	2,976	134,563	90,800	94,662	39,901	50,899
Peak Standard Deviation	2015	12,762	626	1,216	3,604	1,098	15,420	13,713	14,270	1,150	12,563
	2016	10,851	300	1,242	6,814	854	17,044	12,031	12,620	4,424	7,607
Off-Peak Average	2015	79,398	2,903	4,016	16,518	3,474	106,310	83,329	87,564	18,746	64,583
	2016	75,492	2,874	4,084	32,774	3,083	118,298	78,896	82,929	35,369	43,527
Off-Peak Median	2015	77,498	2,951	3,771	16,244	3,345	104,000	81,294	85,179	18,821	62,473
	2016	73,078	2,807	3,745	31,677	2,804	114,390	75,989	80,290	34,100	41,889
Off-Peak Standard Deviation	2015	13,604	592	1,269	3,331	970	16,273	14,785	15,181	1,093	13,692
	2016	12,021	341	1,320	6,845	996	17,810	13,067	13,258	4,553	8,514

Figure 3-20 shows the average hourly cleared volumes of day-ahead demand and real-time demand for the first six months of 2016. The day-ahead demand includes day-ahead load, day-ahead exports, decrement bids and up to congestion transactions. The real-time demand includes real-time load and real-time exports.

Figure 3-20 Day-ahead and real-time demand (Average hourly volumes): January through June, 2016

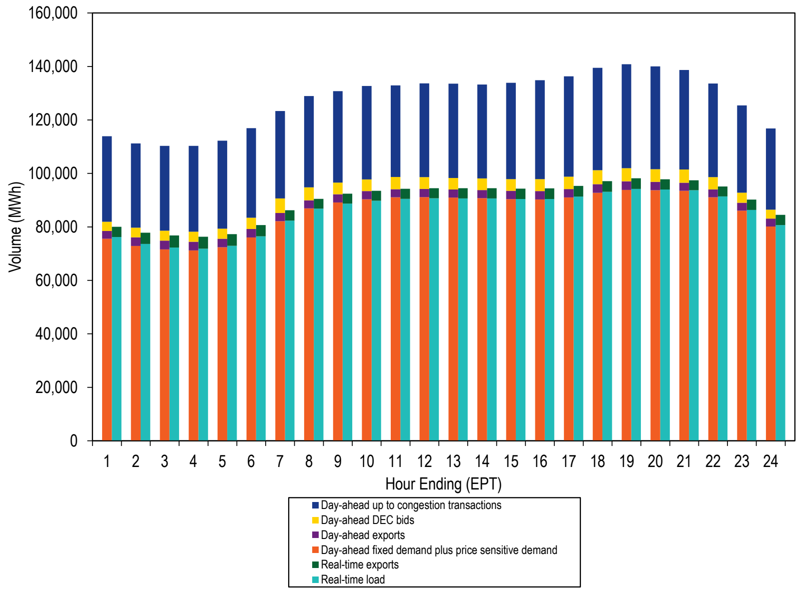


Figure 3-21 Difference between day-ahead and real-time demand (Average daily volumes): 2015 through June 2016

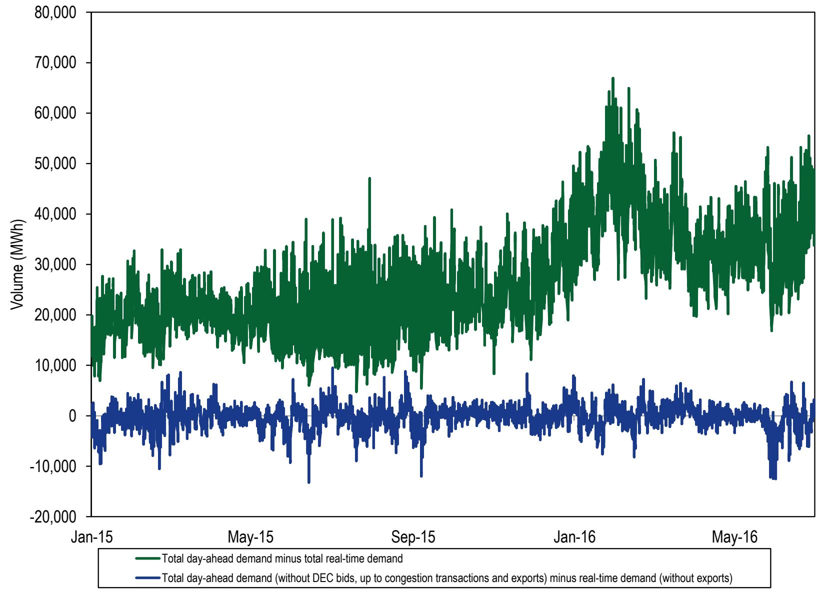


Figure 3-21 shows the difference between the day-ahead and real-time average daily demand from January 1, 2015 through June 30, 2016. There was an increase in up to congestion volume as a result of the expiration of the fifteen month potential refund period for the proceeding related to uplift charges for UTC transactions on December 7, 2015, which increased day-ahead demand.

Supply and Demand: Load and Spot Market

Real-Time Load and Spot Market

Participants in the PJM Real-Time Energy Market can use their own generation to meet load, to sell in the bilateral market or to sell in the spot market in any hour. Participants can both buy and sell via bilateral contracts and buy and sell in the spot market in any hour. If a participant has positive net bilateral transactions in an hour, it is buying energy through bilateral contracts (bilateral purchase). If a participant has negative net bilateral transactions in an hour, it is selling energy through bilateral contracts (bilateral sale). If a participant has positive net spot transactions in an hour, it is buying energy from the spot market (spot purchase). If a participant has negative net spot transactions in an hour, it is selling energy to the spot market (spot sale).

Real-time load is served by a combination of self-supply, bilateral market purchases and spot market purchases. From the perspective of a parent company of a PJM billing organization that serves load, its load could be supplied by any combination of its own generation, net bilateral market purchases and net spot market purchases. In addition to directly serving load, load serving entities can also transfer their responsibility to serve load to other parties through eSchedules transactions referred to as wholesale load responsibility (WLR) or retail load responsibility (RLR) transactions. When the responsibility to serve load is transferred via a bilateral contract, the entity to which the responsibility is transferred becomes the load serving entity. Supply from its own generation (self-supply) means that the parent company is generating power from plants that it owns in order to meet demand. Supply from bilateral purchases means that the parent company is purchasing power under bilateral contracts from a nonaffiliated company at the same time that it is meeting load. Supply from spot market purchases means that the parent company is generating less power from owned plants and/or purchasing less power under bilateral contracts than required to meet load at a defined time and, therefore, is purchasing the required balance from the spot market.

The PJM system's reliance on self-supply, bilateral contracts and spot purchases to meet real-time load is calculated by summing across all the parent companies of PJM billing organizations that serve load in the Real-Time Energy Market for each hour. Table 3-19 shows the monthly average share of real-time load served by self-supply, bilateral contracts and spot purchase in 2015 and the first six months of 2016 based on parent company. In the first six months of 2016, 8.4 percent of real-time load was supplied by bilateral contracts, 26.8 percent by spot market purchase and 64.8 percent by self-supply. Compared with the first six months of 2015, reliance on bilateral contracts increased by 1.9 percentage points, reliance on spot supply decreased by 8.9 percentage points and reliance on self-supply increased by 7.0 percentage points.

Table 3-19 Monthly average percentage of real-time self-supply load, bilateral-supply load and spot-supply load based on parent companies: January 2015 through June 2016[37]

	2015			2016			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	7.1%	32.1%	60.8%	7.1%	28.8%	64.2%	0.0%	(3.3%)	3.3%
Feb	6.6%	32.7%	60.7%	7.5%	28.6%	63.9%	0.9%	(4.1%)	3.2%
Mar	6.2%	34.8%	59.1%	7.6%	29.8%	62.7%	1.4%	(5.0%)	3.6%
Apr	6.6%	37.2%	56.1%	9.2%	24.9%	65.9%	2.5%	(12.3%)	9.8%
May	5.8%	35.9%	58.3%	9.1%	24.2%	66.8%	3.3%	(11.8%)	8.5%
Jun	6.6%	41.3%	52.0%	10.0%	24.3%	65.7%	3.4%	(17.0%)	13.7%
Jul	6.9%	33.8%	59.3%						
Aug	7.0%	28.8%	64.2%						
Sep	7.0%	29.3%	63.7%						
Oct	7.5%	30.2%	62.3%						
Nov	7.2%	29.8%	63.0%						
Dec	7.9%	28.9%	63.3%						
Annual	6.8%	32.9%	60.2%	8.4%	26.8%	64.8%	1.5%	(6.1%)	4.6%

Day-Ahead Load and Spot Market

In the PJM Day-Ahead Energy Market, participants can not only use their own generation, bilateral contracts and spot market purchases to supply their load serving obligation, but can also use virtual resources to meet their load serving obligations in any hour. Virtual supply is treated as supply in the day-ahead analysis and virtual demand is treated as demand in the day-ahead analysis.

The PJM system's reliance on self-supply, bilateral contracts, and spot purchases to meet day-ahead demand (cleared fixed-demand, price-sensitive load and decrement bids) is calculated by summing across all the parent companies of PJM billing organizations that serve demand in the Day-Ahead Energy Market for each hour. Table 3-20 shows the monthly average share of day-ahead demand served by self-supply, bilateral contracts and spot purchases in 2015 through March 2016, based on parent companies. In the first six months of 2016, 8.5 percent of day-ahead demand was supplied by bilateral contracts, 25.7 percent by spot market purchases, and 65.7 percent

37 Table 3-19 and Table 3-20 were calculated as of July 14, 2016. The values may change slightly as billing values are updating by PJM.

by self-supply. Compared with the first six months of 2015, reliance on bilateral contracts decreased by 1.3 percentage points, reliance on spot supply increased by 0.6 percentage points, and reliance on self-supply increased by 0.8 percentage points.

Table 3-20 Monthly average percentage of day-ahead self-supply demand, bilateral supply demand, and spot-supply demand based on parent companies: 2015 through June 2016

	2015			2016			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	10.5%	25.5%	64.0%	8.1%	26.2%	65.7%	(2.4%)	0.7%	1.7%
Feb	9.9%	25.2%	64.9%	8.4%	25.8%	65.8%	(1.5%)	0.6%	0.9%
Mar	9.3%	27.8%	62.9%	7.8%	27.8%	64.4%	(1.5%)	(0.0%)	1.5%
Apr	9.5%	30.3%	60.2%	9.8%	24.6%	65.7%	0.2%	(5.7%)	5.5%
May	9.1%	27.9%	63.0%	9.6%	24.9%	65.6%	0.5%	(3.0%)	2.6%
Jun	8.1%	28.2%	63.8%	8.4%	25.2%	66.5%	0.3%	(3.0%)	2.7%
Jul	8.5%	27.2%	64.3%						
Aug	8.2%	26.9%	64.9%						
Sep	7.9%	27.6%	64.4%						
Oct	8.5%	26.5%	65.0%						
Nov	8.3%	26.1%	65.6%						
Dec	9.3%	25.8%	64.9%						
Annual	8.9%	27.0%	64.0%	8.6%	25.8%	65.6%	(0.3%)	(1.3%)	1.6%

Market Behavior

Offer Capping for Local Market Power

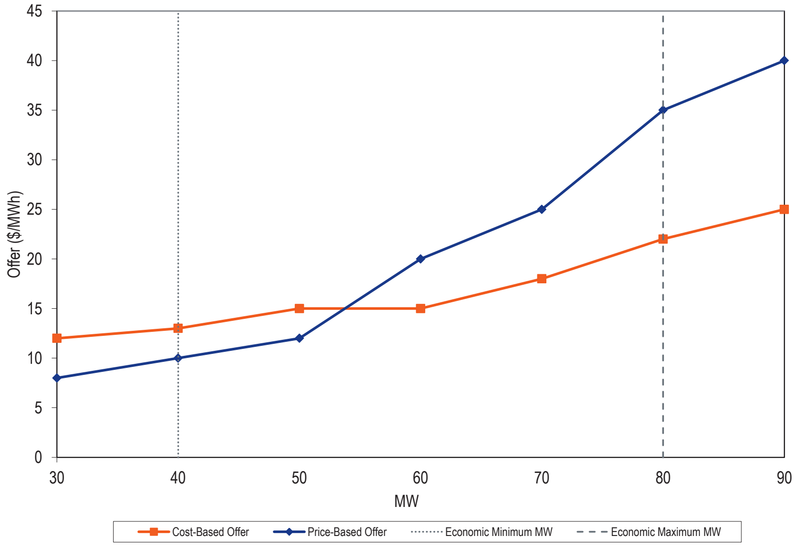
In the PJM Energy Market, offer capping occurs as a result of structurally noncompetitive local markets and noncompetitive offers in the Day-Ahead and Real-Time Energy Markets. PJM also uses offer capping for units that are committed for reliability reasons, specifically for providing black start and reactive service as well as for conservative operations. There are no explicit rules governing market structure or the exercise of market power in the aggregate energy market. PJM's market power mitigation goals have focused on market designs that promote competition and that limit local market power mitigation to situations where the local market structure is not competitive and thus where market design alone cannot mitigate market power.

The analysis of the application of the three pivotal supplier test demonstrates that it is working for most hours to exempt owners when the local market structure is competitive and to offer cap owners when the local market structure is noncompetitive. However, there are some issues with the application of mitigation in the Day-Ahead Energy Market and the Real-Time Energy Market when market sellers fail the TPS test. There is no tariff or manual language that defines in detail the application of the TPS test and offer capping in the Day-Ahead Energy Market and the Real-Time Energy Market.

In both the Day-Ahead and Real-Time Energy Markets, generators have the ability to avoid mitigation by using varying markups in their price-based offers, offering different operating parameters in their price-based and cost-based offers, and using different fuels in their price-based and cost-based offers. These issues can be resolved by simple rule changes.

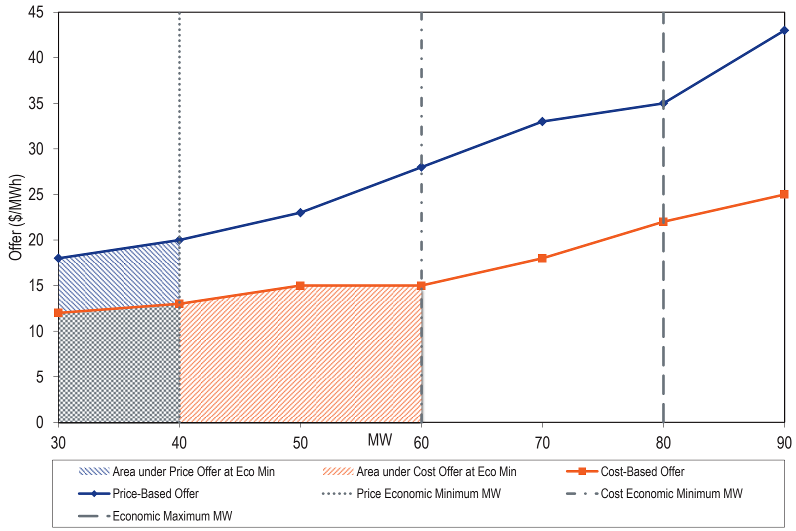
When an owner fails the TPS test, the units offered by the owner that are committed to provide relief are committed on the cheaper of cost or price-based offers. With the ability to submit offer curves with varying markups at different output levels in the price-based offer, units can avoid mitigation by using a low markup at low output levels and a high markup at higher output levels. Figure 3-22 shows an example of offers from a unit that has a negative markup at the economic minimum MW level and a positive markup at the economic maximum MW level. The result would be that a unit that failed the TPS test would be committed on its price-based offer even though the price-based offer is higher than cost at higher output levels and includes positive markups, inconsistent with the explicit goal of local market power mitigation.

Figure 3-22 Offers with varying markups at different MW output levels



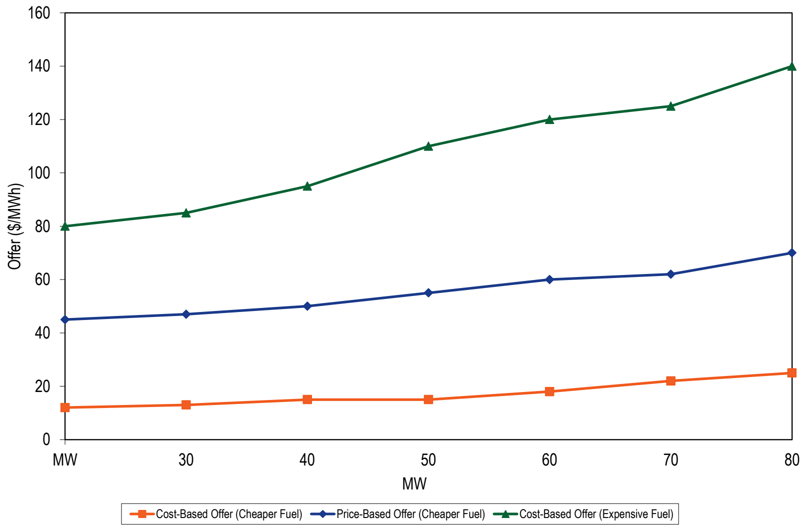
Offering a different economic minimum MW level, different minimum run times, different start up and notification times on the cost-based and price-based offers can also be used to avoid mitigation. For example, a unit may offer its price-based offer with a negative markup, but have a longer minimum run time (MRT) on the price-based offer. For example, a unit may offer a lower economic minimum MW level on the price-based offer than the cost-based offer. Such a unit may appear to be cheaper to commit on the price-based offer even with a positive markup because the total cost of commitment (calculated as a product of MW and the offer in dollars per MWh plus the startup and no-load cost) can be lower on price-based offer at the lower economic minimum level compared to cost-based offer at a higher economic minimum level. Figure 3-23 shows an example of offers from a unit that has a positive markup and a price-based offer with a lower economic minimum MW than the cost-based offer. The cost of commitment (area under the curve) for this unit is lower on the price-based offer than on the cost-based offer. However, the price-based offer includes a positive markup and could result in setting the market price at a noncompetitive level even after the resource owner fails the TPS test.

Figure 3-23 Offers with a positive markup but different economic minimum MW



In case of dual fuel units, if the price-based offer uses a cheaper fuel and the cost-based offer uses a more expensive fuel, the price-based offer will appear to be lower cost even when it includes a markup. Figure 3-24 shows an example of offers by a dual fuel unit, where the active cost-based offer uses a more expensive fuel and the price-based offer uses a cheaper fuel and includes a markup.

Figure 3-24 Dual fuel unit offers



These issues can be solved by simple rule changes.[38] The MMU recommends that markup of price based offers over cost-based offers be constant across the offer curve, that there be at least one cost-based offer using the same fuel as the available price-based offer, and that operating parameters on parameter limited schedules (PLS) be at least as flexible as price-based non-PLS offers.

Levels of offer capping have historically been low in PJM, as shown in Table 3-21. The offer capping percentages shown in Table 3-21 include units that are committed to provide constraint relief whose owners failed the TPS test in the energy market as well as units committed as part of conservative operations, excluding units that were committed for providing black start and reactive service.

Table 3-21 Offer capping statistics – energy only: January through June, 2012 to 2016

	Real-Time		Day-Ahead	
(Jan-Jun)	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2012	1.0%	0.5%	0.1%	0.1%
2013	0.3%	0.1%	0.1%	0.0%
2014	0.7%	0.3%	0.2%	0.1%
2015	0.5%	0.2%	0.2%	0.2%
2016	0.3%	0.2%	0.1%	0.0%

Table 3-22 shows the offer capping percentages including units committed to provide constraint relief and units committed to provide black start service and reactive support. The units that are committed and offer capped for black start service and reactive support reasons increased from 2012 through 2013. Before 2011, the units that ran to provide black start service and reactive support were generally economic in the energy market. From 2011 through 2013, the percentage of hours when these units were not economic (and were therefore committed on their cost schedule for reliability reasons) increased. This trend reversed in 2014, 2015 and 2016 because higher LMPs (in the first six months) resulted in the increased economic dispatch of black start and reactive service resources. As of April 2015, the Automatic Load Rejection (ALR) units that were committed for black start previously no longer provide black start service, and are not included in the offer capping statistics for black start. PJM also created closed loop interfaces to, in some cases, model reactive constraints. The result was higher LMPs, which increased economic dispatch, which contributed to the reduction in units offer capped for reactive support. In instances where units are now committed for the modeled closed loop interface constraints, they are considered offer capped for providing constraint relief. They are included in the offer capping percentages in Table 3-21.

38 The MMU proposed these offer rule changes as part of a broader reform to address generator offer flexibility and associated impact on market power mitigation rules in the Generator Offer Flexibility Senior Task Force (GOFSTF).

Table 3-22 Offer capping statistics for energy and reliability: January through June, 2012 to 2016

	Real-Time		Day-Ahead	
(Jan-Jun)	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2012	1.4%	0.8%	0.1%	0.1%
2013	2.6%	2.1%	3.0%	2.0%
2014	1.1%	0.7%	0.7%	0.5%
2015	1.0%	1.0%	0.8%	0.9%
2016	0.4%	0.2%	0.1%	0.1%

Table 3-23 shows the offer capping percentages for units committed to provide black start service and reactive support. The data in Table 3-23 is the difference between the offer cap percentages shown in Table 3-22 and Table 3-21.

Table 3-23 Offer capping statistics for reliability: January through June, 2012 to 2016

	Real-Time		Day-Ahead	
(Jan-Jun)	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2012	0.4%	0.3%	0.0%	0.0%
2013	2.3%	2.0%	2.9%	2.0%
2014	0.4%	0.4%	0.5%	0.4%
2015	0.5%	0.7%	0.6%	0.7%
2016	0.0%	0.0%	0.0%	0.0%

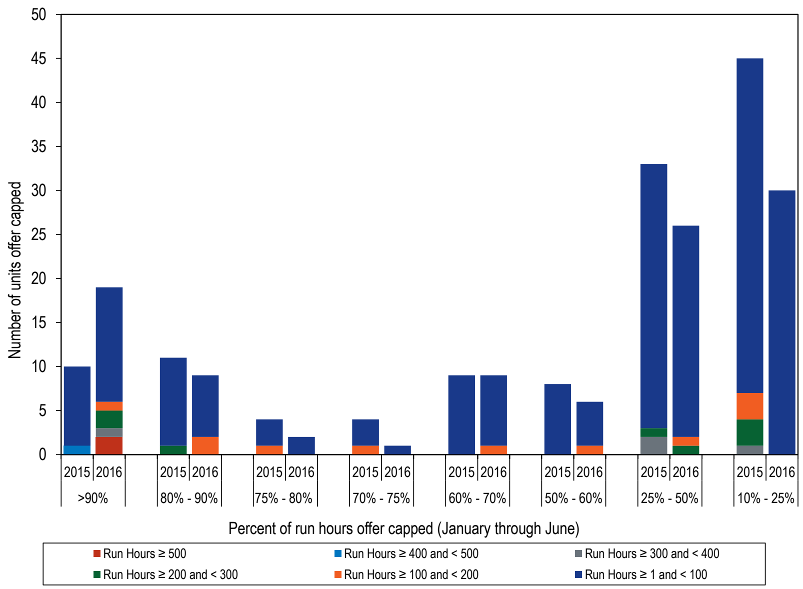
Table 3-24 presents data on the frequency with which units were offer capped in the first six months of 2015 and 2016 for failing the TPS test to provide energy for constraint relief in the Real-Time Energy Market. Table 3-24 shows that nineteen units were offer capped for 90 percent or more of their run hours in the first six months of 2016 compared to ten in the first six months of 2015.

Table 3-24 Real-time offer capped unit statistics: January through June, 2015 and 2016

		Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	(Jan - Jun)	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	2016	2	0	1	2	1	13
	2015	0	1	0	0	0	9
80% and < 90%	2016	0	0	0	0	2	7
	2015	0	0	0	1	0	10
75% and < 80%	2016	0	0	0	0	0	2
	2015	0	0	0	0	1	3
70% and < 75%	2016	0	0	0	0	0	1
	2015	0	0	0	0	1	3
60% and < 70%	2016	0	0	0	0	1	8
	2015	0	0	0	0	0	9
50% and < 60%	2016	0	0	0	0	1	5
	2015	0	0	0	0	0	8
25% and < 50%	2016	0	0	0	1	1	24
	2015	0	0	2	1	0	30
10% and < 25%	2016	0	0	0	0	0	30
	2015	0	0	1	3	3	38

Figure 3-25 shows the frequency with which units were offer capped in the first six months of 2015 and 2016 for failing the TPS test to provide energy for constraint relief in the Real-Time Energy Market.

Figure 3-25 Real-time offer capped unit statistics: January through June, 2015 and 2016



TPS Test Statistics

In the first six months of 2016, the AECO, AEP, AP, BGE, ComEd, Dominion, DPL, JCPL, PECO, PENELEC, and PSEG control zones experienced congestion resulting from one or more constraints binding for 50 or more hours or resulting from an interface constraint. The ATSI, DAY, DEOK, DLCO, EKPC, Met-Ed, Pepco, PPL and RECO control zones did not have constraints binding for 50 or more hours in the first six months of 2016. Table 3-25 shows that AEP, AP, BGE, ComEd, and PSEG were the control zones that experienced congestion resulting from one or more constraints binding for 50 or more hours or resulting from an interface constraint that was binding for one or more hours in every year in the first six months of 2009 through 2016.

Table 3-25 Numbers of hours when control zones experienced congestion resulting from one or more constraints binding for 50 or more hours or from an interface constraint: January through June, 2009 through 2016

	(Jan - Jun)							
	2009	2010	2011	2012	2013	2014	2015	2016
AECO	149	69	88	0	0	0	0	383
AEP	932	355	1,228	322	811	1,773	1,902	471
AP	198	410	52	113	51	170	451	79
ATSI	101	0	0	1	70	403	464	0
BGE	90	154	184	1,556	316	1,142	3,079	4,923
ComEd	576	1,406	153	845	1,678	1,729	1,727	2,910
DEOK	0	0	0	58	0	0	69	0
DLCO	156	342	0	209	0	281	747	0
Dominion	310	589	659	200	0	52	1,422	647
DPL	0	0	0	126	142	560	1,199	1,399
EKPC	0	0	0	0	0	65	0	0
JCPL	0	0	0	0	0	0	79	168
Met-Ed	0	0	0	68	0	0	182	0
PECO	59	0	130	53	256	944	485	732
PENELEC	55	0	0	0	0	1,441	1,385	551
Pepco	0	0	59	203	85	39	0	0
PPL	176	0	52	146	261	147	0	0
PSEG	438	479	605	316	1,462	2,023	2,591	52

The local market structure in the Real-Time Energy Market associated with each of the frequently binding constraints was analyzed using the three pivotal supplier results in the first six months of 2016.[39] The three pivotal supplier (TPS) test is applied every time the system solution indicates that out of merit resources are needed to relieve a transmission constraint. Only uncommitted resources, which would be started to relieve the transmission constraint, are subject to offer capping. Already committed units that can provide incremental relief cannot be offer capped. The results of the TPS test are shown for tests that could have resulted in offer capping and tests that resulted in offer capping.

Overall, the results confirm that the three pivotal supplier test results in offer capping when the local market is structurally noncompetitive and

39 See the *MMU Technical Reference for PJM Markets*, at "Three Pivotal Supplier Test" for a more detailed explanation of the three pivotal supplier test. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>

does not result in offer capping when that is not the case. Local markets are noncompetitive when the number of suppliers is relatively small.

Table 3-26 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owners passing and failing for the transfer interface constraints.

Table 3-26 Three pivotal supplier test details for interface constraints: January through June, 2016

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
AEP - DOM	Peak	537	867	10	0	10
	Off Peak	372	548	10	0	10
Bedington - Black Oak	Peak	132	215	12	3	9
	Off Peak	91	121	10	2	8
Western	Peak	157	232	12	4	8
	Off Peak	0	0	0	0	0
Warren	Peak	37	38	1	0	1
	Off Peak	49	57	1	0	1

Table 3-27 Summary of three pivotal supplier tests applied for interface constraints: January through June, 2016

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
AEP - DOM	Peak	6	3	50%	2	33%	67%
	Off Peak	19	3	16%	2	11%	67%
Bedington - Black Oak	Peak	225	21	9%	4	2%	19%
	Off Peak	150	11	7%	5	3%	45%
Western	Peak	12	2	17%	1	8%	50%
	Off Peak	0	0	0%	0	0%	0%
Warren	Peak	149	0	0%	0	0%	0%
	Off Peak	13	0	0%	0	0%	0%

The three pivotal supplier test is applied every time the PJM market system solution indicates that incremental relief is needed to relieve a transmission constraint. While every system solution that requires incremental relief to transmission constraints will result in a test, not all tested providers of effective supply are eligible for capping. Only uncommitted resources, which would be started as a result of incremental relief needs, are eligible to be offer capped. Already committed units that can provide incremental relief cannot, regardless of test score, be switched from price to cost offers. Table 3-27 provides, for the identified interface constraints, information on total tests applied, the subset of three pivotal supplier tests that could have resulted in the offer capping of uncommitted units and the portion of those tests that did result in offer capping uncommitted units.

Parameter Limited Schedules

All capacity resources in PJM are required to submit at least one cost-based offer. All cost-based offers, submitted by resources that are not capacity performance resources, are parameter limited in accordance with the Parameter Limited Schedule (PLS) matrix or to the level of a prior approved exception.[40] During the delivery year 2016-2017, all cost-based offers, submitted by capacity performance resources, are parameter limited in accordance with predetermined unit specific parameter limits. All capacity resources that choose to offer price-based schedules are required to make available at least one price-based parameter limited schedule (price-based PLS schedule). For resources that are not capacity performance resources, this schedule is to be used by PJM for committing generation resources when a maximum emergency generation alert is declared. For capacity performance resources, the price-based parameter

40 See PJM, OATT, § 6.6 Minimum Generator Operating Parameters - Parameter-Limited Schedules, (September 10, 2014), pp. 1937- 1940.

limited schedule is to be used by PJM for committing generation resources when hot weather and cold weather alerts are declared.

During the extreme cold weather conditions in the first three months of 2016 as well as 2015 and 2014, a number of gas fired generators requested temporary exceptions to parameter limits for their parameter limited schedules due to restrictions imposed by natural gas pipelines. The parameters that were affected because of gas pipeline restrictions include minimum run time (MRT) and turn down ratio (TDR, ratio of economic maximum MW to economic minimum MW). When pipelines issue critical notices and enforce ratable take requirements, generators may be forced to nominate an equal amount of gas for each hour in a 24 hour period, with penalties for deviating from the nominated quantity. This led to requests for 24 hour minimum run times and turn down ratios close to 1.0, to avoid deviations from the hourly nominated quantity.

Key parameters like startup and notification time were not included in the PLS matrix in the first six months of 2016 and prior periods. Some resource owners notified PJM that they needed extended notification times based on the claimed necessity for generation owners to nominate gas prior to gas nomination cycle deadlines. Startup and notification times are limited for Capacity Performance resources beginning June 1, 2016, in accordance with predetermined unit specific parameter limits. The unit specific parameter limits for Capacity Performance resources were based on default minimum operating parameter limits posted by PJM by technology type. These default parameters were based on analysis by the MMU. Market participants could request an adjustment to the default values by submitting documentation to support the physical operating constraints of their units, which was reviewed by PJM and the MMU. The default minimum operating parameter limits or an approved adjusted values are used by Capacity Performance resources for their parameter limited schedules.

Currently, there are no rules in the PJM tariff or manuals that limit the nonparameter attributes of price-based PLS offers. The intent of the price-based PLS offer is to prevent the exercise of market power during high demand conditions by preventing units from offering inflexible operating parameters in order to extract higher market revenues or higher uplift payments. However, a generator can include a higher markup in the price-based PLS offer than in the price-based non-PLS schedule. The result is that the offer is higher and market prices are higher as a result of the exercise of market power using the PLS offer. This defeats the purpose of requiring price-based PLS offers.

The MMU recommends that in order to ensure rigorous market power mitigation when the TPS test is failed, the operating parameters in the cost-based offer and the price-based parameter limited schedule (PLS) offer be at least as flexible as the operating parameters in the available non-PLS price-based offer, and that the price-MW pairs in the price-based PLS offer be exactly equal to the price-based non-PLS offer.

Parameter Limited Schedules under Capacity Performance

Beginning in delivery year 2016/2017, resources that have Capacity Performance (CP) commitments are required to submit, in their parameter limited schedules (cost-based offers and price-based PLS offers), unit specific parameters that reflect the physical capability of the technology type of the resource. In its order on Capacity Performance, the Commission determined that resources should be able to reflect actual constraints based on not just the resource physical constraints, but also other constraints, such as contractual limits that are not based on the physical characteristics of the generator.[41] The Commission found that it is unjust and unreasonable to not provide uplift payments to resources with parameters based on non-physical constraints.[42] The Commission directed PJM to submit tariff language to establish a process through which resources that operate outside the defined unit-specific parameter limits can justify such operation and therefore remain eligible for make whole payments.[43]

A primary goal of the capacity performance market design is to assign performance risk to generation owners and to ensure that capacity prices reflect underlying supply and demand conditions, including the cost of

41 *PJM Interconnection, L.L.C. et al.*, 151 FERC ¶ 61,208 at P 437 (June 9th Order).
42 *Id* at P 439.
43 *Id* at P 440.

taking on performance risk. The Order's determination on parameters is not consistent with that goal. By permitting generation owners to establish unit parameters based on nonphysical limits, the June 9th Order has weakened the incentives for units to be flexible and has weakened the assignment of performance risk to generation owners. Contractual limits, unlike generating unit operational limits, are a function of the interests and incentives of the parties to the contracts. If a generation owner expects to be compensated through uplift payments for running for 24 hours regardless of whether the energy is economic or needed, that generation owner has no incentive to pay more to purchase the flexible gas service that would permit the unit to be flexible in response to dispatch.

The fact that a contract may be just and reasonable because it was an arm's length contract entered into by two willing parties does not mean that is the only possible arrangement between the two parties or that it is consistent with an efficient market outcome. The actual contractual terms are a function of the incentives and interests of the parties. The fact that a just and reasonable contract exists between a generation owner and a gas supplier does not mean that it is appropriate or efficient to impose the resultant costs on electric customers or that it incorporates an efficient allocation of performance risk between the generation owner and other market participants.

The approach to parameters defined in the June 9th Order would increase energy market uplift payments substantially. Uplift costs are unpredictable, opaque and unhedgeable. Electric customers are not in a position to determine the terms of the contracts that resources enter into. Customers rely on the market rules to create incentives that protect them by assigning operational risk to generators, who are in the best position to efficiently manage those risks.

The MMU recommends that the revised rules recognize the difference between operational parameters that indicate to PJM dispatchers what a unit is capable of during the operating day and the parameters that are reflected in uplift payments. The parameters provided to PJM dispatchers each day should reflect what units are physically capable of. That is an operational necessity. However, the parameters which determine the amount of uplift payments to those generators should reflect the flexibility goals of the capacity performance construct.

The MMU recommends that resources be held to the OEM operating parameters of the capacity market CONE reference resource for performance assessment and energy uplift payments. This solution creates the incentives for flexibility and preserves, to the extent possible, the incentives to follow PJM's dispatch instructions during tight conditions. The proposed operating parameters should be based on the physical capability of the Reference Resource used in the Cost of New Entry, currently two GE Frame 7FA turbines with dual fuel capability. All resources that are less flexible than the Reference Resource are expected to be scheduled and running during tight conditions anyway, while the flexible CTs that are used as peaking plants would still have the incentive to follow LMP and dispatch instructions. CCs would also have the capability to be as flexible as the reference resource. These units will be exempt from nonperformance charges and made whole as long as they perform in accordance with their parameters. This ensures that all the peaking units that are needed by PJM for flexible operation do not self schedule at their maximum output, and follow PJM dispatch instructions during tight conditions. If any of the less flexible resources need to be dispatched down by PJM for reliability reasons, they would be exempt from nonperformance charges.

Such an approach is consistent with the Commission's no excuses policy for nonperformance because the flexibility target is set based on the optimal OEM-defined capability for the marginal resource that is expected to meet peak demand, which is consistent with the level of performance that customers are paying for in the capacity market. Any resource that is less flexible is not excused for nonperformance and any resource that meets the flexibility target is performing according to the commitments made in the capacity market.

The June 9th Order pointed out that the way to ensure that a resource's parameters are exposed to market consequences is to not allow any parameter limitations as an excuse for nonperformance. The same logic should apply to energy market uplift rules. A resource's parameters should be exposed to market consequences and the resource should not be made whole if it is operating less flexibly than the reference resource. Paying energy market uplift on the basis of parameters consistent with the flexibility goals of the capacity performance construct would ensure that performance incentives are consistent across the capacity and energy markets and ensure that performance risk is appropriately assigned to generation owners.

Markup Index

The markup index is a summary measure of participant offer behavior or conduct for individual marginal units. The markup index for each marginal unit is calculated as (Price – Cost)/Price.[44] The markup index is normalized and can vary from -1.00 when the offer price is less than short run marginal cost, to 1.00 when the offer price is higher than short run marginal cost. The markup index does not measure the impact of unit markup on total LMP.

Real-Time Markup

Table 3-28 shows the average markup index of marginal units in the Real-Time Energy Market, by offer price category using unadjusted cost offers. Table 3-29 shows the average markup index of marginal units in the Real-Time Energy Market, by offer price category using adjusted cost offers. The markup is negative if the cost-based offer of the marginal unit exceeds its price-based offer at its operating point. In the first six months of 2016, 89.4 percent of marginal units had average dollar markups less than zero, when using unadjusted offers. In the first six months of 2016, 89.4 percent of marginal units had average dollar markups less than zero, when using adjusted offers. The data shows that some marginal units did have substantial markups. Among the units that were marginal in the first six months of 2016, none of them had offer prices above $400 per MWh. Among the units that were marginal in the first six months of 2015, 0.30 percent of units had offer prices greater than $400 per MWh with average dollar markup of $56.87 per MWh. Using the unadjusted cost offers, the highest markup in the first six months of 2016 was $258.16 while the highest markup in the first six months of 2015 was $792.21.

44 In order to normalize the index results (i.e., bound the results between +1.00 and -1.00), the index is calculated as (Price – Cost)/Price when price is greater than cost, and (Price – Cost)/Cost when price is less than cost.

Table 3-28 Average, real-time marginal unit markup index (By offer price category unadjusted): January through June, 2015 and 2016

	2015 (Jan-Jun)			2016 (Jan-Jun)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	(0.05)	($2.60)	35.2%	0.02	($0.78)	69.4%
$25 to $50	(0.03)	($1.30)	48.4%	(0.04)	($2.66)	20.0%
$50 to $75	0.06	$3.27	4.0%	0.16	$8.99	1.4%
$75 to $100	0.10	$7.35	1.6%	0.34	$29.69	0.5%
$100 to $125	0.09	$9.02	1.5%	0.05	$5.99	2.1%
$125 to $150	0.06	$6.92	1.4%	0.01	$1.04	4.8%
>= $150	0.05	$12.10	7.9%	0.04	$7.14	1.8%

Table 3-29 Average, real-time marginal unit markup index (By offer price category adjusted): January through June, 2015 and 2016

	2015 (Jan-Jun)			2016 (Jan-Jun)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	(0.01)	($1.53)	35.2%	0.06	$0.11	69.4%
$25 to $50	0.02	$0.31	48.4%	0.01	($0.81)	20.0%
$50 to $75	0.08	$4.41	4.0%	0.18	$9.86	1.4%
$75 to $100	0.10	$7.84	1.6%	0.34	$30.41	0.5%
$100 to $125	0.09	$9.34	1.5%	0.05	$6.00	2.1%
$125 to $150	0.06	$7.20	1.4%	0.01	$1.04	4.8%
>= $150	0.05	$12.29	7.9%	0.04	$7.18	1.8%

Table 3-30 shows the average highest markup of all offered units by the fuel type. Unlike a marginal unit's markup, which was calculated at the specified dispatch point, the highest markup offered by a unit within its economic operating range is included in this measure.

In the first six months of 2016, the average highest markup of a coal unit was $19.90 per MWh. In the first six months of 2015, the average highest markup of a coal unit was $7.74. In the first six months of 2016, the average highest markup of a natural gas unit was $20.33 per MWh. In the first six months of 2015, the average highest markup of a natural gas unit was $25.96 per MWh.

Table 3-30 Average, real-time offered unit markup (By Fuel Price Unadjusted): January through June, 2015 and 2016

	2015 (Jan-Jun)	2016 (Jan-Jun)
Fuel Type	Average Highest Markup	Average Highest Markup
Coal	$7.74	$19.90
Gas	$25.96	$20.33
Municipal Waste	$8.46	$0.29
Oil	$64.94	$38.01
Other	$54.94	$19.04
Uranium	($0.36)	($0.82)
Wind	($3.32)	($2.86)

Day-Ahead Markup

Table 3-31 shows the average markup index of marginal units in the Day-Ahead Energy Market, by offer price category using unadjusted offers. In the first six months of 2016, 62.9 percent of marginal units had average dollar markups less than zero and an average markup index less than or equal to 0.00. The data show that some marginal units in the first six months of 2016 did have substantial markups. The average markup index increased significantly, for example, from 0.11 in the first six months of 2015, to 0.42 in the first six months of 2016 in the offer price category from $50 to $75.

Table 3-31 Average day-ahead marginal unit markup index (By offer price category, unadjusted): January through June, 2015 and 2016

	2015 (Jan - Jun)			2016 (Jan - Jun)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	0.03	($0.67)	34.6%	(0.01)	($0.07)	62.9%
$25 to $50	0.01	$0.33	53.7%	0.19	$5.25	24.8%
$50 to $75	0.11	$6.28	3.3%	0.42	$23.24	1.6%
$75 to $100	0.04	$2.52	1.6%	0.10	$8.24	0.1%
$100 to $125	(0.00)	($2.50)	1.2%	0.03	$3.44	0.6%
$125 to $150	(0.00)	($3.19)	1.2%	0.01	$1.71	7.7%
>= $150	0.02	$4.01	4.0%	0.01	$2.95	1.8%

Table 3-32 shows the average markup index of marginal units in the Day-Ahead Energy Market, by offer price category using adjusted offers. In the first six months of 2016, 0.00 percent of marginal units had average dollar markups less than zero and an average markup index less than or equal to 0.00. The average markup index increased significantly, for example, from 0.13 in the first six months of 2015, to 0.45 in the first six months of 2016 in the offer price category from $50 to $75.

Table 3-32 Average day-ahead marginal unit markup index (By offer price category, adjusted): January through June, 2015 and 2016

	2015 (Jan - Jun)			2016 (Jan - Jun)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	0.07	$0.56	34.6%	0.03	$0.82	62.9%
$25 to $50	0.06	$1.95	53.7%	0.23	$6.62	24.8%
$50 to $75	0.13	$7.51	3.3%	0.45	$24.89	1.6%
$75 to $100	0.04	$2.76	1.6%	0.10	$8.24	0.1%
$100 to $125	0.00	($1.97)	1.2%	0.03	$3.44	0.6%
$125 to $150	0.00	($2.84)	1.2%	0.01	$1.71	7.7%
>= $150	0.03	$4.07	4.0%	0.01	$2.95	1.8%

Frequently Mitigated Units and Associated Units

An FMU is a frequently mitigated unit. The results reported here include units that were mitigated for any reason, including both structural market power in the energy market and units called on for reliability reasons, including reactive and black start service.

The FMU adder was filed with FERC in 2005, and approved effective February 2006.[45] The goal, in 2005, was to ensure that units that were offer capped for most of their run hours could cover their going forward or avoidable costs (also known as ACR in the PJM Capacity Market). That function became unnecessary with the introduction of the RPM capacity market design in 2007, and changes to the scarcity pricing rules in 2012. Under the RPM design, units can make offers in the capacity market that include their ACR net of net revenues. Thus, if there is a shortfall in ACR recovery, that shortfall is included

45 110 FERC ¶ 61,053 (2005).

in the RPM offer. If the unit clears in RPM, it covers its shortfall in ACR costs. If the unit does not clear, then the market result means that PJM can provide reliability without the unit and no additional revenue is needed.

For those reasons, the MMU recommended the elimination of FMU and AU adders.[46] FMU and AU adders no longer serve the purpose for which they were created and interfere with the efficient operation of PJM markets.

The MMU and PJM proposed a compromise on the elimination of FMU adders that maintains the ability of generating units to qualify for FMU adders when units have net revenues less than unit going forward costs or ACR. PJM submitted the joint MMU/PJM proposal to the Commission pursuant to section 206 of the Federal Power Act. On October 31, 2014, the Commission conditionally approved the filing and the new rule became effective November 1, 2014.

The definition of FMUs provides for a set of graduated adders associated with increasing levels of offer capping. Units capped for 60 percent or more of their run hours and less than 70 percent are eligible for an adder of either 10 percent of their cost-based offer or $20 per MWh. Units capped for 70 percent or more of their run hours and less than 80 percent are eligible for an adder of either 10 percent of their cost-based offer or $30 per MWh. Units capped for 80 percent or more of their run hours are eligible for an adder of either 10 percent of their cost-based offer or $40 per MWh. These categories are designated Tier 1, Tier 2 and Tier 3.

In addition to being offer capped for the designated percent of run hours, in order to qualify for an FMU adder, a generating unit's Projected PJM Market Revenues plus the unit's PJM capacity market revenues on a rolling 12-month basis, divided by the unit's MW of installed capacity (in $/MW-year) must be less than its accepted unit specific Avoidable Cost Rate (in $/MW-year) (excluding APIR and ARPIR), or its default Avoidable Cost Rate (in $/MW-year) if no unit-specific Avoidable Cost Rate is accepted for the BRAs for the Delivery Years included in the rolling 12-month period, determined pursuant to Sections 6.7 and 6.8 of Attachment DD of the Tariff. (The relevant Avoidable Cost Rate is the weighted average of the Avoidable Cost Rates for each Delivery Year included in the rolling 12-month period, weighted by month.) No portion of the unit may be included in an FRR capacity plan or be receiving compensation under Part V of the PJM Tariff and the unit must be internal to the PJM Region and subject only to PJM dispatch.[47]

An AU, or associated unit, is a unit that is physically, electrically and economically identical to an FMU, but does not qualify for the same FMU adder based on the number of run-hours the unit is offer capped.[48] For example, if a generating station had two identical units with identical electrical impacts on the system, one of which was offer capped for more than 80 percent of its run hours, that unit would be designated a Tier 3 FMU. If the second unit were capped for 30 percent of its run hours, that unit would be an AU and receive the same Tier 3 adder as the FMU at the site. The AU designation was implemented to ensure that the associated unit is not dispatched in place of the FMU, resulting in no effective adder for the FMU. In the absence of the AU designation, the associated unit would be an FMU after its dispatch and the FMU would be dispatched in its place after losing its FMU designation.

Figure 3-26 shows the total number of FMUs and AUs that qualified for an adder since the inception of the business rule in February 2006. The new rules for determining the qualification of a unit as an FMU or AU became effective November 1, 2014. FMUs and AUs are designated monthly, and a unit's capping percentage is based on a rolling 12-month average, effective with a one-month lag.[49] The number of units that were eligible for an FMU or AU adder declined from an average of 70 units during the first 11 months of 2014, to zero since December 2014.

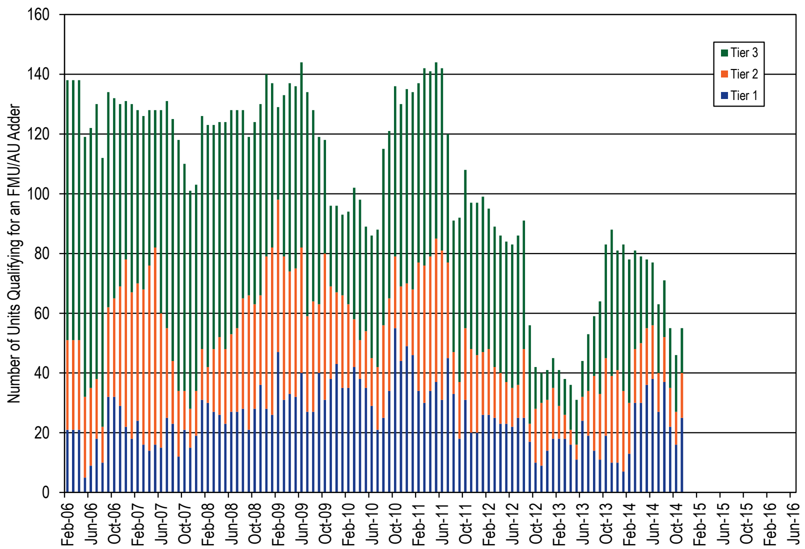
46 See the *"FMU Problem Statement and Issue Charge,"* <http://www.monitoringanalytics.com/reports/Presentations/2013/IMM_MIC_FMU_Problem_Statement_and_Issue_Charge_20130306.pdf>

47 PJM. OA, Schedule 1 § 6.4.2.

48 An associated unit (AU) must belong to the same design class (where a design class includes generation that is the same size and utilizes the same technology, without regard to manufacturer) and uses the identical primary fuel as the FMU.

49 PJM. OA, Schedule 1 § 6.4.2. In 2007, the FERC approved OA revisions to clarify the AU criteria.

Figure 3-26 Frequently mitigated units and associated units (By month): February, 2006 through June, 2016



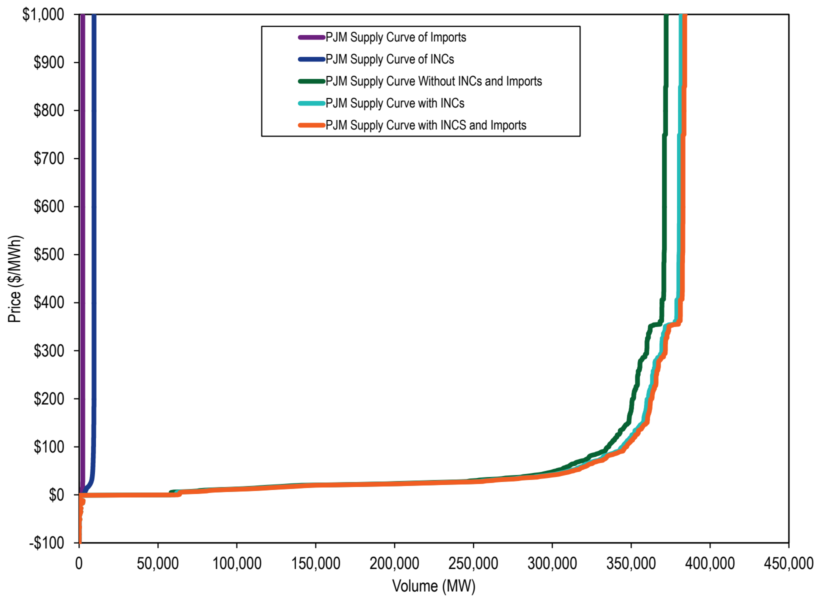
Virtual Offers and Bids

There is a substantial volume of virtual offers and bids in the PJM Day-Ahead Energy Market and such offers and bids may be marginal, based on the way in which the PJM optimization algorithm works.

Any market participant in the PJM Day-Ahead Energy Market can use increment offers, decrement bids, up to congestion transactions, import transactions and export transactions as financial instruments that do not require physical generation or load. Increment offers and decrement bids may be submitted at any hub, transmission zone, aggregate, or single bus for which LMP is calculated. Up to congestion transactions may be submitted between any two buses on a list of 431 buses, eligible for up to congestion transaction bidding.[50] Financial Transaction Rights (FTRs) bids may be submitted at any bus on a list of selected buses that change every planning period, eligible for FTRs. Import and export transactions may be submitted at any interface pricing point, where an import is equivalent to a virtual offer that is injected into PJM and an export is equivalent to a virtual bid that is withdrawn from PJM.

Figure 3-27 shows the PJM day-ahead daily aggregate supply curve of increment offers, the system aggregate supply curve of imports, the system aggregate supply curve without increment offers and imports, the system aggregate supply curve with increment offers, and the system aggregate supply curve with increment offers and imports for an example day in 2016.

Figure 3-27 PJM day-ahead aggregate supply curves: 2016 example day



50 Market participants were required to specify an interface pricing point as the source for imports, an interface pricing point as the sink for exports or an interface pricing point as both the source and sink for transactions wheeling through PJM. On November 1, 2012, PJM eliminated this requirement. For the list of eligible sources and sinks for up to congestion transactions, see www.pjm.com *"OASIS-Source-Sink-Link.xls,"*<http://www.pjm.com/~/media/etools/oasis/references/oasis-source-sink-link.ashx>.

Table 3-33 shows the hourly average number of cleared and submitted increment offers and decrement bids by month for January 2015 through June 2016. The hourly average submitted and cleared increment MW increased by 15.0 and 11.3 percent, from 7,190 MW and 4,713 MW in the first six months of 2015 to 8,268 MW and 5,245 MW in the first six months of 2016. The hourly average submitted decrement MW decreased by 1.7 percent and cleared decrement MW increased by 0.8 percent, from 7,366 MW and 4,300 MW in the first six months of 2015 to 7,239 MW and 4,332 MW in the first six months of 2016.

Table 3-33 Hourly average number of cleared and submitted INCs, DECs by month: January 2015 through June 2016

		Increment Offers				Decrement Bids			
Year		Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
2015	Jan	4,350	6,447	78	398	5,153	7,320	76	295
2015	Feb	4,754	7,109	116	578	4,511	7,445	72	409
2015	Mar	4,973	8,689	142	760	4,305	8,894	101	648
2015	Apr	4,511	6,351	187	558	3,453	6,990	84	451
2015	May	5,089	7,459	181	656	4,171	6,823	94	404
2015	Jun	4,592	7,043	143	697	4,196	6,696	89	410
2015	Jul	4,101	6,534	128	745	3,335	5,830	86	448
2015	Aug	4,457	6,956	135	749	3,433	5,506	74	398
2015	Sep	4,527	6,772	148	733	4,391	7,030	112	437
2015	Oct	4,631	7,112	199	846	3,990	6,757	112	462
2015	Nov	5,022	7,822	223	1,008	3,671	6,435	109	482
2015	Dec	5,102	7,775	189	1,010	4,028	6,869	129	486
2015	Annual	4,675	7,175	156	729	4,051	6,879	95	444
2016	Jan	5,035	8,093	174	1,066	4,286	7,569	100	534
2016	Feb	4,831	8,710	178	1,150	4,259	8,158	113	572
2016	Mar	5,715	8,548	208	1,045	3,690	6,357	101	502
2016	Apr	5,630	8,343	186	964	4,115	7,066	101	509
2016	May	5,113	7,652	161	976	4,321	6,256	103	477
2016	Jun	5,130	8,291	153	1,054	5,344	8,107	128	585
2016	Annual	5,245	8,268	177	1,042	4,332	7,239	108	529

Table 3-34 shows the average hourly number of up to congestion transactions and the average hourly MW for January 2015 through June 2016. In the first six months of 2016, the average hourly up to congestion submitted MW increased 101.9 percent and cleared MW increased 98.7 percent, compared to the first six months of 2015, as a result of the expiration of the fifteen month potential refund period for the proceeding related to uplift charges for UTC transactions in December 2015. Section 206(b) of the Federal Power Act states that "...the Commission may order refunds of any amounts paid, for the period subsequent to the refund effective date through a date fifteen months after such refund effective date..."[51]

Table 3-34 Hourly average of cleared and submitted up to congestion bids by month: January 2015 through June 2016

		Up to Congestion			
Year		Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
2015	Jan	15,903	46,626	806	2,132
2015	Feb	17,255	57,318	892	2,695
2015	Mar	18,382	72,906	978	2,909
2015	Apr	16,300	73,446	811	2,734
2015	May	18,929	81,358	941	3,219
2015	Jun	17,714	81,452	896	3,220
2015	Jul	18,883	88,543	952	3,502
2015	Aug	18,490	102,084	1,126	4,291
2015	Sep	20,779	108,730	1,451	4,909
2015	Oct	20,183	100,673	1,493	4,736
2015	Nov	20,880	86,857	1,468	4,067
2015	Dec	27,124	99,083	1,933	4,841
2015	Annual	19,255	83,422	1,147	3,611
2016	Jan	39,446	135,369	2,455	6,015
2016	Feb	38,818	152,891	2,091	5,748
2016	Mar	31,938	147,963	1,704	5,094
2016	Apr	29,212	128,349	2,689	6,079
2016	May	32,883	120,132	2,977	6,006
2016	Jun	35,469	151,414	2,528	6,406
2016	Annual	34,607	139,199	2,409	5,889

Table 3-35 shows the average hourly number of import and export transactions and the average hourly MW for January 2015 through June 2016. In the first six months of 2016, the average hourly submitted and cleared import transaction MW decreased by 40.2 and 34.7 percent, and the average hourly

51 16 U.S.C. § 824e.

submitted and cleared export transaction MW decreased 16.2 and 15.7 percent, compared to the first six months of 2015.

Table 3-35 Hourly average number of cleared and submitted import and export transactions by month: January 2015 through June 2016

		Imports				Exports			
Year		Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
2015	Jan	2,579	4,559	26	26	4,473	4,559	26	26
2015	Feb	4,383	4,469	23	25	4,383	4,469	23	25
2015	Mar	3,268	3,302	16	17	3,268	3,302	16	17
2015	Apr	2,624	2,626	13	13	2,624	2,626	13	13
2015	May	2,612	2,623	17	17	2,612	2,623	17	17
2015	Jun	2,895	2,906	14	14	2,895	2,906	14	14
2015	Jul	2,961	2,983	14	14	2,961	2,983	14	14
2015	Aug	3,209	3,239	15	15	3,209	3,239	15	15
2015	Sep	3,873	3,913	18	18	3,873	3,913	18	18
2015	Oct	2,190	2,197	11	11	2,190	2,197	11	11
2015	Nov	2,715	2,734	15	15	2,715	2,734	15	15
2015	Dec	2,475	2,483	13	13	2,475	2,483	13	13
2015	Annual	3,131	3,160	16	17	3,131	3,160	16	17
2016	Jan	2,059	2,103	15	16	2,564	2,571	13	14
2016	Feb	2,396	2,480	20	22	2,634	2,653	13	13
2016	Mar	2,097	2,145	17	18	2,324	2,330	11	11
2016	Apr	2,150	2,180	16	16	2,620	2,635	13	13
2016	May	1,889	1,947	12	14	2,484	2,492	14	15
2016	Jun	1,335	1,366	6	7	4,428	4,471	23	24
2016	Annual	1,986	2,035	14	15	2,837	2,853	15	15

Table 3-36 shows the frequency with which generation offers, import or export transactions, up to congestion transactions, decrement bids, increment offers and price-sensitive demand are marginal for the first six months of 2015 and 2016.

Figure 3-28 shows the monthly volume of bid and cleared INC, DEC and up to congestion bids by month for the period from January 2005 through June 2016.

Table 3-36 Type of day-ahead marginal units: January through June, 2015 and 2016

	2015						2016				
	Generation	Dispatchable Transaction	Up to Congestion Transaction	Decrement Bid	Increment Offer	Price Sensitive Demand	Generation	Dispatchable Transaction	Up to Congestion Transaction	Decrement Bid	Increment Offer
Jan	14.2%	0.5%	71.9%	6.9%	6.3%	0.1%	5.3%	0.1%	85.2%	5.6%	3.8%
Feb	13.1%	0.4%	73.1%	7.6%	5.6%	0.1%	5.5%	0.0%	83.5%	7.4%	3.6%
Mar	10.0%	0.7%	73.3%	10.6%	5.3%	0.0%	7.0%	0.1%	80.6%	7.7%	4.7%
Apr	10.4%	0.3%	73.2%	10.8%	5.3%	0.0%	5.8%	0.0%	82.3%	8.1%	3.7%
May	10.2%	0.1%	75.2%	9.2%	5.3%	0.0%	6.2%	0.1%	83.8%	6.5%	3.4%
Jun	8.0%	0.1%	78.2%	9.5%	4.1%	0.0%	3.5%	0.0%	84.2%	8.5%	3.7%
Annual	11.0%	0.4%	74.1%	9.1%	5.4%	0.0%	5.5%	0.1%	83.3%	7.3%	3.8%

Figure 3-28 Monthly bid and cleared INCs, DECs and UTCs (MW): January 2005 through June 2016

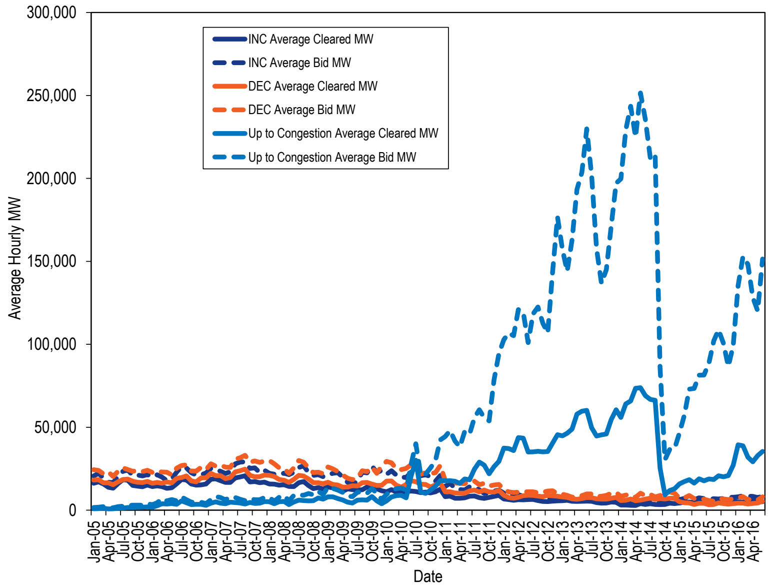


Figure 3-29 Daily bid and cleared INCs, DECs, and UTCs (MW): 2015 through June 2016

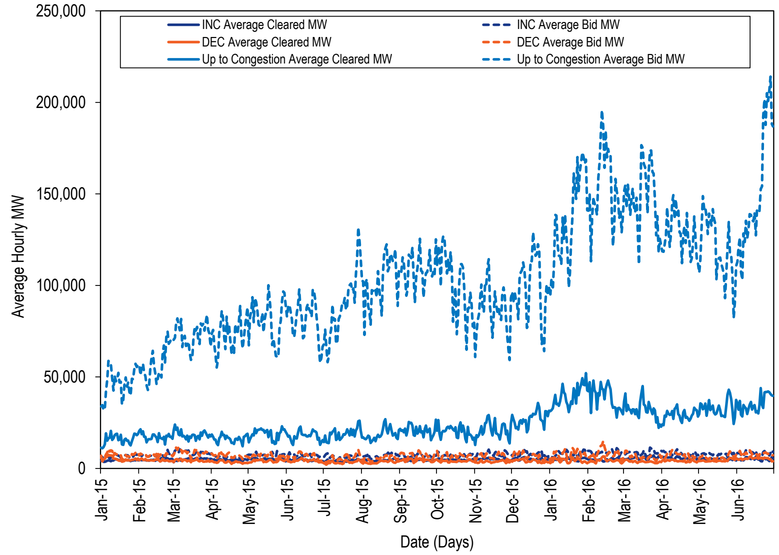


Figure 3-29 shows the daily volume of bid and cleared INC, DEC and up to congestion bids for the period from January 2015 through June 2016.

In order to evaluate the ownership of virtual bids, the MMU categorizes all participants making virtual bids in PJM as either physical or financial. Physical entities include utilities and customers which primarily take physical positions in PJM markets. Financial entities include banks and hedge funds which primarily take financial positions in PJM markets. International market participants that primarily take financial positions in PJM markets are generally considered to be financial entities even if they are utilities in their own countries.

Table 3-37 shows, for the first six months of 2015 and 2016, the total increment offers and decrement bids and cleared MW by whether the parent organization is financial or physical.

Table 3-37 PJM INC and DEC bids and cleared MW by type of parent organization (MW): January through June, 2015 and 2016

	Jan-Jun 2015				Jan-Jun 2016			
Category	Total Virtual Bid MW	Percent	Total Virtual Cleared MW	Percent	Total Virtual Bid MW	Percent	Total Virtual Cleared MW	Percent
Financial	26,667,613	42.2%	7,753,951	19.9%	34,784,319	51.4%	13,696,238	32.7%
Physical	36,544,243	57.8%	31,227,205	80.1%	32,930,167	48.6%	28,128,133	67.3%
Total	63,211,856	100.0%	38,981,156	100.0%	67,714,486	100.0%	41,824,370	100.0%

Table 3-38 shows, for the first six months of 2015 and 2016, the total up to congestion bids and cleared MW by whether the parent organization is financial or physical.

Table 3-38 PJM up to congestion transactions by type of parent organization (MW): January through June, 2015 and 2016

	Jan-Jun 2015				Jan-Jun 2016			
Category	Total Up to Congestion Bid MW	Percent	Total Up to Congestion Cleared MW	Percent	Total Up to Congestion Bid MW	Percent	Total Up to Congestion Cleared MW	Percent
Financial	273,823,300	91.4%	62,602,499	82.7%	574,350,507	94.5%	138,496,938	91.6%
Physical	25,682,155	8.6%	13,073,994	17.3%	33,543,256	5.5%	12,661,343	8.4%
Total	299,505,455	100.0%	75,676,494	100.0%	607,893,763	100.0%	151,158,281	100.0%

Table 3-39 shows for the first six months of 2015 and 2016, the total import and export transactions by whether the parent organization is financial or physical.

Table 3-39 PJM import and export transactions by type of parent organization (MW): January through June, 2015 and 2016

	Jan-Jun 2015		Jan-Jun 2016	
Category	Total Import and Export MW	Percent	Total Import and Export MW	Percent
Financial	10,531,899	40.4%	8,544,178	37.8%
Physical	15,561,730	59.6%	14,084,557	62.2%
Total	26,093,629	100.0%	22,628,735	100.0%

Table 3-40 shows increment offers and decrement bids bid by top ten locations for the first six months of 2015 and 2016.

Table 3-40 PJM virtual offers and bids by top ten locations (MW): January through June, 2015 and 2016

Jan-Jun 2015					Jan-Jun 2016				
Aggregate/Bus Name	Aggregate/ Bus Type	INC MW	DEC MW	Total MW	Aggregate/Bus Name	Aggregate/ Bus Type	INC MW	DEC MW	Total MW
WESTERN HUB	HUB	9,644,293	11,368,368	21,012,662	WESTERN HUB	HUB	11,344,223	10,738,691	22,082,914
SOUTHIMP	INTERFACE	4,116,718	0	4,116,718	SOUTHIMP	INTERFACE	2,581,862	0	2,581,862
IMO	INTERFACE	2,553,011	36,819	2,589,830	N ILLINOIS HUB	HUB	571,541	1,104,654	1,676,195
N ILLINOIS HUB	HUB	446,003	1,625,506	2,071,509	MISO	INTERFACE	222,980	1,439,780	1,662,760
NYIS	INTERFACE	1,036,204	201,609	1,237,813	NYIS	INTERFACE	847,338	583,312	1,430,650
LINDENVFT	INTERFACE	200,100	560,299	760,399	BGE	ZONE	255,618	1,127,731	1,383,348
MISO	INTERFACE	225,653	484,675	710,328	AEP-DAYTON HUB	HUB	678,070	360,689	1,038,759
BGE	ZONE	81,842	578,517	660,359	PEPCO	ZONE	255,807	406,009	661,816
BOCGASE2138 KV T1	LOAD	113,791	526,349	640,140	IMO	INTERFACE	608,336	2,397	610,733
AEP-DAYTON HUB	HUB	260,402	360,024	620,427	PECO	ZONE	477,733	105,529	583,262
Top ten total		18,678,019	15,742,166	34,420,185			17,843,507	15,868,790	33,712,297
PJM total		31,169,922	31,964,981	63,134,903			36,107,139	31,613,123	67,720,262
Top ten total as percent of PJM total		59.9%	49.2%	54.5%			49.4%	50.2%	49.8%

Table 3-41 shows up to congestion transactions by import bids for the top ten locations for the first six months of 2015 and 2016.[52]

52 The source and sink aggregates in these tables refer to the name and location of a bus and do not include information about the behavior of any individual market participant.

Table 3-41 PJM cleared up to congestion import bids by top ten source and sink pairs (MW): January through June, 2015 and 2016

Jan-Jun 2015				
Imports				
Source	Source Type	Sink	Sink Type	MW
SOUTHIMP	INTERFACE	NAGELAEP	EHVAGG	1,380,592
OVEC	INTERFACE	AEP-DAYTON HUB	HUB	327,713
SOUTHIMP	INTERFACE	WOLF HILLS 1-5	AGGREGATE	303,812
SOUTHEAST	INTERFACE	HALIFXDP TX1	AGGREGATE	243,761
NORTHWEST	INTERFACE	N ILLINOIS HUB	HUB	232,246
NORTHWEST	INTERFACE	COMED	ZONE	214,222
SOUTHEAST	INTERFACE	NAGELAEP	EHVAGG	207,520
SOUTHWEST	INTERFACE	NAGELAEP	EHVAGG	189,037
MISO	INTERFACE	21 KINCA ATR24304	AGGREGATE	188,052
SOUTHEAST	INTERFACE	DOM	ZONE	154,826
Top ten total				3,441,780
PJM total				10,751,372
Top ten total as percent of PJM total				32.0%
Jan-Jun 2016				
Imports				
Source	Source Type	Sink	Sink Type	MW
HUDSONTP	INTERFACE	LEONIA 230 T-2	AGGREGATE	366,487
MISO	INTERFACE	COOK	EHVAGG	340,774
NEPTUNE	INTERFACE	SOUTHRIV 230	AGGREGATE	309,611
SOUTHWEST	INTERFACE	DUMONT	EHVAGG	306,355
OVEC	INTERFACE	COOK	EHVAGG	276,877
NIPSCO	INTERFACE	DUMONT	EHVAGG	248,920
OVEC	INTERFACE	CONESVILLE 5	AGGREGATE	246,745
OVEC	INTERFACE	CABOT	EHVAGG	224,582
MISO	INTERFACE	112 WILTON	EHVAGG	207,638
SOUTHWEST	INTERFACE	COOK	EHVAGG	204,254
Top ten total				2,732,244
PJM total				14,773,440
Top ten total as percent of PJM total				18.5%

Table 3-42 shows up to congestion transactions by export bids for the top ten locations for the first six months of 2015 and 2016.

Table 3-42 PJM cleared up to congestion export bids by top ten source and sink pairs (MW): January through June, 2015 and 2016

Jan-Jun 2015				
Exports				
Source	Source Type	Sink	Sink Type	MW
FOWLER RIDGE II WF	AGGREGATE	SOUTHWEST	INTERFACE	222,312
ROCKPORT	EHVAGG	SOUTHWEST	INTERFACE	139,271
21 KINCA ATR24304	AGGREGATE	NIPSCO	INTERFACE	102,734
COMED	ZONE	NIPSCO	INTERFACE	95,445
MARION	AGGREGATE	HUDSONTP	INTERFACE	85,622
SULLIVAN-AEP	EHVAGG	OVEC	INTERFACE	83,097
FOWLER RIDGE II WF	AGGREGATE	OVEC	INTERFACE	78,238
KAMMER 2	AGGREGATE	NIPSCO	INTERFACE	75,128
ROCKPORT	EHVAGG	OVEC	INTERFACE	70,132
RECO	ZONE	HUDSONTP	INTERFACE	68,907
Top ten total				1,020,885
PJM total				3,967,356
Top ten total as percent of PJM total				25.7%
Jan-Jun 2016				
Exports				
Source	Source Type	Sink	Sink Type	MW
COMED	ZONE	NIPSCO	INTERFACE	692,806
SULLIVAN-AEP	EHVAGG	OVEC	INTERFACE	539,698
21 KINCA ATR24304	AGGREGATE	NIPSCO	INTERFACE	498,037
21 KINCA ATR24404	AGGREGATE	SOUTHWEST	INTERFACE	338,505
21 KINCA ATR24304	AGGREGATE	SOUTHWEST	INTERFACE	325,965
EAST BEND 2	AGGREGATE	SOUTHWEST	INTERFACE	244,826
GRAND RIDGE WF	AGGREGATE	NIPSCO	INTERFACE	220,924
CLOVERDALE	EHVAGG	SOUTHEXP	INTERFACE	206,033
NAGELAEP	EHVAGG	SOUTHEXP	INTERFACE	203,856
STMARYSGEN	AGGREGATE	NIPSCO	INTERFACE	202,965
Top ten total				3,473,616
PJM total				11,052,092
Top ten total as percent of PJM total				31.4%

Table 3-43 shows up to congestion transactions by wheel bids for the top ten locations for the first six months of 2015 and 2016.

Table 3-43 PJM cleared up to congestion wheel bids by top ten source and sink pairs (MW): January through June, 2015 and 2016

Jan-Jun 2015				
Wheels				
Source	Source Type	Sink	Sink Type	MW
MISO	INTERFACE	NORTHWEST	INTERFACE	164,983
MISO	INTERFACE	NIPSCO	INTERFACE	102,566
NORTHWEST	INTERFACE	MISO	INTERFACE	97,460
IMO	INTERFACE	NYIS	INTERFACE	66,458
NYIS	INTERFACE	IMO	INTERFACE	49,286
SOUTHWEST	INTERFACE	IMO	INTERFACE	32,526
SOUTHWEST	INTERFACE	SOUTHEXP	INTERFACE	28,262
NIPSCO	INTERFACE	IMO	INTERFACE	25,972
SOUTHEAST	INTERFACE	SOUTHEXP	INTERFACE	17,399
NYIS	INTERFACE	HUDSONTP	INTERFACE	13,525
Top ten total				598,438
PJM total				711,420
Top ten total as percent of PJM total				84.1%
Jan-Jun 2016				
Wheels				
Source	Source Type	Sink	Sink Type	MW
NORTHWEST	INTERFACE	MISO	INTERFACE	228,710
MISO	INTERFACE	NIPSCO	INTERFACE	212,775
NYIS	INTERFACE	IMO	INTERFACE	199,662
SOUTHWEST	INTERFACE	SOUTHEXP	INTERFACE	127,399
MISO	INTERFACE	NORTHWEST	INTERFACE	116,012
IMO	INTERFACE	NYIS	INTERFACE	99,453
SOUTHWEST	INTERFACE	NIPSCO	INTERFACE	59,197
IMO	INTERFACE	MISO	INTERFACE	42,405
NEPTUNE	INTERFACE	NYIS	INTERFACE	31,556
MISO	INTERFACE	SOUTHEXP	INTERFACE	29,966
Top ten total				1,147,135
PJM total				1,311,291
Top ten total as percent of PJM total				87.5%

On November 1, 2012, PJM eliminated the requirement for market participants to specify an interface pricing point as either the source or sink of an up to congestion transaction. The top ten internal up to congestion transaction locations were 6.0 percent of the PJM total internal up to congestion transactions in the first six months of 2016.

Table 3-44 shows up to congestion transactions by internal bids for the top ten locations for the first six months of 2015 and 2016.

Table 3-44 PJM cleared up to congestion internal bids by top ten source and sink pairs (MW): January through June, 2015 and 2016

Jan-Jun 2015				
Internal				
Source	Source Type	Sink	Sink Type	MW
BERGEN 2CC	AGGREGATE	LEONIA 230 T-1	AGGREGATE	1,290,717
BYRON 1	AGGREGATE	ROCKFORD	AGGREGATE	850,874
JEFFERSON	EHVAGG	COOK	EHVAGG	782,156
ROCKPORT	EHVAGG	JEFFERSON	EHVAGG	681,127
ATSI GEN HUB	HUB	ATSI	ZONE	600,494
VALLEY	EHVAGG	DOOMS	EHVAGG	475,999
RONCO	EHVAGG	HATFIELD	EHVAGG	470,056
BERGEN 2CC	AGGREGATE	LEONIA 230 T-2	AGGREGATE	453,816
167 PLANO	EHVAGG	112 WILTON	EHVAGG	428,844
ALBURTIS	EHVAGG	PPL	ZONE	418,148
Top ten total				6,452,231
PJM total				60,246,346
Top ten total as percent of PJM total				10.7%
Jan-Jun 2016				
Internal				
Source	Source Type	Sink	Sink Type	MW
21 KINCA ATR24404	AGGREGATE	MICHFE	AGGREGATE	921,085
BERGEN 2CC	AGGREGATE	LEONIA 230 T-1	AGGREGATE	860,351
21 KINCA ATR24304	AGGREGATE	MICHFE	AGGREGATE	779,519
112 WILTON	EHVAGG	DUMONT	EHVAGG	742,469
BYRON 1	AGGREGATE	ROCKFORD	AGGREGATE	672,241
ROCKPORT	EHVAGG	JEFFERSON	EHVAGG	601,522
WHIPPANY BK 7	AGGREGATE	TRAYNOR	AGGREGATE	532,314
CLOVERDALE	EHVAGG	CLOVERD2 138 KV T4	AGGREGATE	528,634
BLACKOAK	EHVAGG	BEDINGTON	EHVAGG	528,608
MOUNTAINEER	EHVAGG	COOK	EHVAGG	500,895
Top ten total				6,667,638
PJM total				124,025,599
Top ten total as percent of PJM total				5.4%

Table 3-45 shows the number of source-sink pairs that were offered and cleared monthly in January 2013 through June 2016. The annual row in Table 3-45 is the average hourly number of offered and cleared source-sink pairs for the year for the average columns and the maximum hourly number of offered and cleared source-sink pairs for the year for the maximum columns. The increase in average offered and cleared source-sink pairs beginning in January 2013 and continuing through the first eight months of 2014 illustrates that PJM's modification of the rules governing the location of up to congestion transactions bids resulted in a significant increase in the number of offered and cleared up to congestion transactions. The subsequent reduction in up to congestion transactions (UTC) that followed a FERC order setting September 8, 2014, as the effective date for any uplift charges subsequently assigned to UTCs, was reversed. There was an increase in up to congestion volume as a result of the expiration of the fifteen month refund period for the proceeding related to uplift charges for UTC transactions on December 7, 2015.[53]

Table 3-45 Number of PJM offered and cleared source and sink pairs: January 2013 through June 2016

		Daily Number of Source-Sink Pairs			
Year	Month	Average Offered	Max Offered	Average Cleared	Max Cleared
2013	Jan	6,580	10,548	3,291	5,060
2013	Feb	4,891	7,415	2,755	3,907
2013	Mar	4,858	7,446	2,868	4,262
2013	Apr	6,426	9,064	3,464	4,827
2013	May	5,729	7,914	3,350	4,495
2013	Jun	6,014	8,437	3,490	4,775
2013	Jul	5,955	9,006	3,242	4,938
2013	Aug	6,215	9,751	3,642	5,117
2013	Sep	3,496	4,222	2,510	3,082
2013	Oct	4,743	7,134	3,235	4,721
2013	Nov	8,605	14,065	5,419	8,069
2013	Dec	8,346	11,728	6,107	7,415
2013	Annual	5,996	14,065	3,620	8,069
2014	Jan	7,977	11,191	5,179	7,714
2014	Feb	10,087	11,688	7,173	8,463
2014	Mar	11,360	14,745	7,284	9,943
2014	Apr	11,487	14,106	8,589	10,253
2014	May	11,215	13,477	7,734	9,532
2014	Jun	10,613	14,112	7,374	10,143
2014	Jul	10,057	12,304	7,202	8,486
2014	Aug	10,877	12,863	7,609	9,254
2014	Sep	5,618	11,269	4,281	8,743
2014	Oct	2,871	4,092	1,972	2,506
2014	Nov	2,463	3,988	1,812	3,163
2014	Dec	2,803	3,672	2,197	2,786
2014	Annual	8,109	10,614	5,690	7,570
2015	Jan	3,337	5,422	2,263	3,270
2015	Feb	4,600	7,041	2,775	4,147
2015	Mar	4,061	5,799	2,625	3,244
2015	Apr	3,777	6,967	2,343	3,378
2015	May	4,025	5,513	2,587	3,587
2015	Jun	3,852	5,967	2,781	3,748
2015	Jul	3,957	5,225	2,786	4,044
2015	Aug	4,996	6,143	3,702	4,378
2015	Sep	5,775	7,439	4,222	5,462
2015	Oct	6,000	7,414	4,221	5,397
2015	Nov	5,846	7,148	4,494	5,842
2015	Dec	7,097	8,250	5,709	6,610
2015	Annual	4,259	6,152	2,897	3,912
2016	Jan	7,714	8,793	6,174	7,374
2016	Feb	9,200	11,172	7,203	7,957
2016	Mar	8,826	11,572	6,338	8,126
2016	Apr	7,697	8,473	5,958	6,767
2016	May	8,521	9,398	6,707	7,273
2016	Jun	9,261	10,948	6,913	7,770
2016	Annual	8,536	10,059	6,549	7,545

53 See 148 FERC ¶ 61,144 (2014).

Table 3-46 and Figure 3-30 show total cleared up to congestion transactions by type for the first six months of 2015 and 2016. Internal up to congestion transactions in the first six months of 2016 were 82.0 percent of all up to congestion transactions compared to 79.6 percent in the first six months of 2015.

Table 3-46 PJM cleared up to congestion transactions by type (MW): January through June, 2015 and 2016

	Jan-Jun 2015				
	Cleared Up to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	3,441,780	1,020,885	598,438	6,452,231	11,513,334
PJM total (MW)	10,751,372	3,967,356	711,420	60,246,346	75,676,494
Top ten total as percent of PJM total	32.0%	25.7%	84.1%	10.7%	15.2%
PJM total as percent of all up-to congestion transactions	14.2%	5.2%	0.9%	79.6%	100.0%
	Jan-Jun 2016				
	Cleared Up to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	2,732,244	3,473,616	1,147,135	6,667,638	14,020,633
PJM total (MW)	14,773,440	11,052,092	1,311,291	124,025,599	151,162,422
Top ten total as percent of PJM total	18.5%	31.4%	87.5%	5.4%	9.3%
PJM total as percent of all up-to congestion transactions	9.8%	7.3%	0.9%	82.0%	100.0%

Figure 3-30 shows the initial increase and continued increase in internal up to congestion transactions by month following the November 1, 2012 rule change permitting such transactions, until September 8, 2014. The reduction in up to congestion transactions (UTC) that followed a FERC order setting September 8, 2014, as the effective date for any uplift charges subsequently assigned to UTCs, was reversed. There was an increase in up to congestion volume as a result of the expiration of the fifteen month refund period for the proceeding related to uplift charges for UTC transactions.[54]

Figure 3-30 PJM monthly cleared up to congestion transactions by type (MW): January 2005 through June 2016

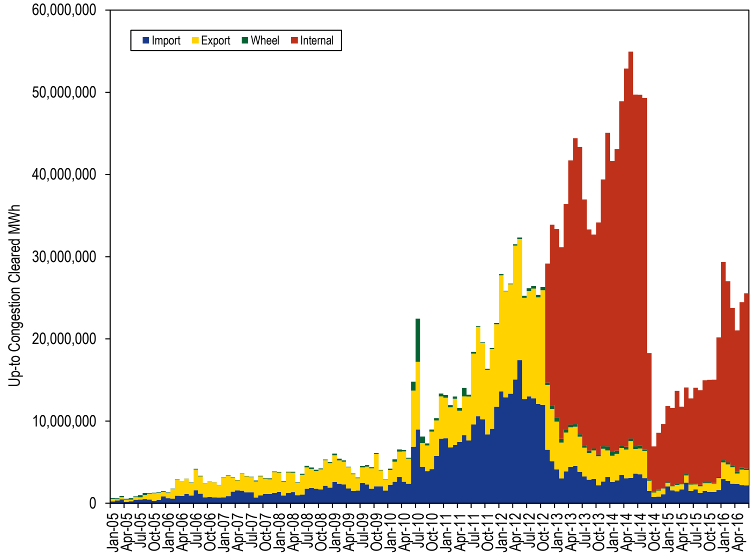
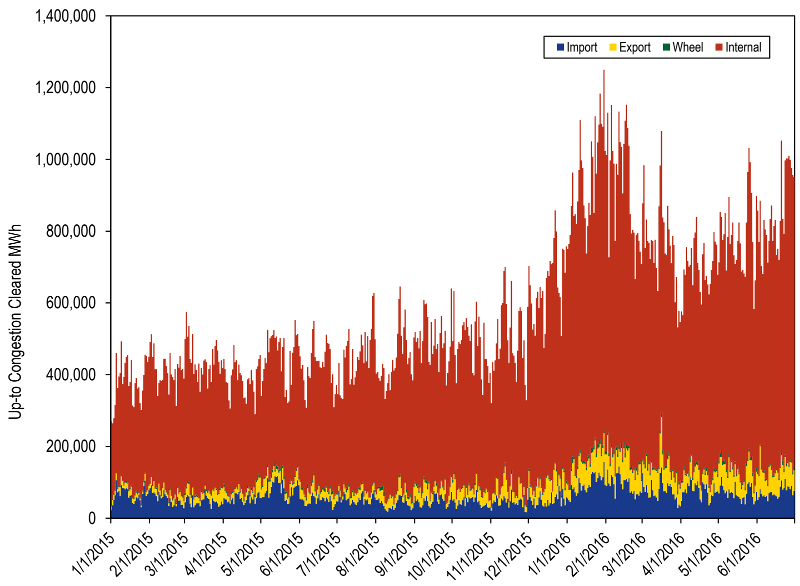


Figure 3-31 shows the daily cleared up to congestion MW by transaction type for the period from January 2015 through June 2016.

54 See 148 FERC ¶ 61,144 (2014).

Figure 3-31 PJM daily cleared up to congestion transaction by type (MW): January 2015 through June 2016



Generator Offers

Generator offers are categorized as dispatchable (Table 3-47) or self scheduled (Table 3-48).[55] Units which are available for economic dispatch are dispatchable. Units which are self scheduled to generate fixed output are self scheduled and must run. Units which are self scheduled at their economic minimum and are available for economic dispatch up to their economic maximum are self scheduled and dispatchable. Table 3-47 and Table 3-48 do not include units that did not indicate their offer status and units that were offered as available to run only during emergency events. The MW offered beyond the economic range of a unit are categorized as emergency MW. The emergency MW are included in both tables.

Table 3-47 shows the proportion of MW offers by dispatchable units, by unit type and by offer price range, for the first six months of 2016. For example, 77.1 percent of CC offers were dispatchable and in the $0 to $200 per MWh price range. The total column is the proportion of all MW offers by unit type that were dispatchable. For example, 84.7 percent of all CC MW offers were dispatchable, including the 7.0 percent of emergency MW offered by CC units. The all dispatchable offers row is the proportion of MW that were offered as available for economic dispatch within a given range by all unit types. For example, 48.5 percent of all dispatchable offers were in the $0 to $200 per MWh price range. The total column in the all dispatchable offers row is the proportion of all MW offers that were offered as available for economic dispatch, including emergency MW. Among all the generator offers in the first six months of 2016, 52.5 percent were offered as available for economic dispatch.

Table 3-47 Distribution of MW for dispatchable unit offer prices: January through June, 2016

	Dispatchable (Range)							
Unit Type	($200) - $0	$0 - $200	$200 - $400	$400 - $600	$600 - $800	$800 - $1,000	Emergency	Total
CC	0.0%	77.1%	0.3%	0.2%	0.0%	0.0%	7.0%	84.7%
CT	0.0%	82.0%	4.4%	0.5%	0.5%	0.0%	11.0%	98.4%
Diesel	3.0%	31.7%	16.6%	5.4%	0.0%	0.0%	17.7%	74.5%
Fuel Cell	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Nuclear	0.0%	6.1%	0.0%	0.0%	0.0%	0.0%	0.1%	6.2%
Pumped Storage	63.9%	0.1%	0.0%	0.0%	0.0%	0.0%	2.2%	66.3%
Run of River	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%
Solar	34.0%	5.8%	0.0%	0.0%	0.0%	0.0%	1.8%	41.6%
Steam	0.1%	47.6%	0.7%	0.0%	0.0%	0.2%	2.8%	51.4%
Transaction	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Wind	50.3%	10.2%	0.0%	0.0%	0.0%	0.0%	0.5%	61.1%
All Dispatchable Offers	2.5%	48.5%	1.2%	0.2%	0.1%	0.1%	4.5%	57.1%

55 Each range in the tables is greater than or equal to the lower value and less than the higher value. The unit type battery is not included in these tables because batteries do not make energy offers. The unit type fuel cell is not included in these tables because of the small number owners and the small number of units of this type of generation.

Table 3-48 shows the proportion of MW offers by unit type that were self scheduled to generate fixed output and by unit type and price range for self-scheduled and dispatchable units, for the first six months of 2016. For example, 9.9 percent of CC offers were self scheduled and dispatchable and in the $0 to $200 price range. The total column is the proportion of all MW offers by unit type that were self scheduled to generate fixed output and are self scheduled and dispatchable. For example, 15.3 percent of all CC MW offers were either self scheduled to generate at fixed output or self scheduled to generate at economic minimum and dispatchable up to economic maximum, including the 1.1 percent of emergency MW offered by CC units. The all self scheduled offers row is the proportion of MW that were offered as either self scheduled to generate at fixed output or self scheduled to generate at economic minimum and dispatchable up to economic maximum within a given range by all unit types. For example, units that were self scheduled to generate at fixed output accounted for 22.0 percent of all offers and self scheduled and dispatchable units accounted for 17.9 percent of all offers. The total column in the all self scheduled offers row is the proportion of all MW offers that were either self scheduled to generate at fixed output or self scheduled to generate at economic minimum and dispatchable up to economic maximum, including emergency MW. Among all the generator offers in the first six months of 2016, 23.6 percent were offered as self scheduled and 19.4 percent were offered as self scheduled and dispatchable.

Table 3-48 Distribution of MW for self scheduled offer prices: January through June, 2016

	Self Scheduled		Self Scheduled and Dispatchable (Range)							
Unit Type	Must Run	Emergency	($200) - $0	$0 - $200	$200 - $400	$400 - $600	$600 - $800	$800 - $1,000	Emergency	Total
CC	3.0%	1.1%	0.4%	9.9%	0.0%	0.0%	0.0%	0.0%	0.9%	15.3%
CT	0.7%	0.1%	0.0%	0.7%	0.1%	0.0%	0.0%	0.0%	0.0%	1.6%
Diesel	19.3%	1.0%	2.2%	1.6%	0.0%	0.0%	0.0%	0.0%	1.3%	25.5%
Fuel Cell	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Nuclear	88.7%	1.1%	3.1%	0.9%	0.0%	0.0%	0.0%	0.0%	0.1%	93.8%
Pumped Storage	17.9%	9.2%	2.8%	0.0%	0.0%	0.0%	0.0%	0.0%	3.8%	33.7%
Run of River	60.0%	13.3%	0.2%	19.6%	0.0%	0.0%	0.0%	0.7%	6.0%	99.8%
Solar	41.9%	15.0%	1.4%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	58.4%
Steam	4.9%	1.7%	0.2%	38.8%	0.0%	0.0%	0.0%	0.0%	2.9%	48.6%
Transaction	76.2%	23.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Wind	4.6%	3.9%	23.4%	3.2%	0.0%	0.0%	0.0%	0.0%	3.7%	38.9%
All Self-Scheduled Offers	22.0%	1.6%	1.2%	16.6%	0.0%	0.0%	0.0%	0.0%	1.5%	42.9%

Market Performance

The PJM average locational marginal price (LMP) reflects the configuration of the entire RTO. The PJM Energy Market includes the Real-Time Energy Market and the Day-Ahead Energy Market.

Markup

The markup index, which is a measure of participant conduct for individual marginal units, does not measure the impact of participant behavior on market prices. As an example, if unit A has a $90 cost and a $100 price, while unit B has a $9 cost and a $10 price, both would show a markup of 10 percent, but the price impact of unit A's markup at the generator bus would be $10 while the price impact of unit B's markup at the generator bus would be $1. Depending on each unit's location on the transmission system, those bus-level impacts could also translate to different impacts on total system price.

The MMU calculates the impact on system prices of marginal unit price-cost markup, based on analysis using sensitivity factors. The calculation shows the markup component of price-based on a comparison between the price-based offer and the cost-based offer of each actual marginal unit on the system.[56]

56 This is the same method used to calculate the fuel cost adjusted LMP and the components of LMP.

The price impact of markup must be interpreted carefully. The markup calculation is not based on a full redispatch of the system to determine the marginal units and their marginal costs that would have occurred if all units had made all offers at short run marginal cost. Thus the results do not reflect a counterfactual market outcome based on the assumption that all units made all offers at short run marginal cost. It is important to note that a full redispatch analysis is practically impossible and a limited redispatch analysis would not be dispositive. Nonetheless, such a hypothetical counterfactual analysis would reveal the extent to which the actual system dispatch is less than competitive if it showed a difference between dispatch based on short run marginal cost and actual dispatch. It is possible that the unit-specific markup, based on a redispatch analysis, would be lower than the markup component of price if the reference point were an inframarginal unit with a lower price and a higher cost than the actual marginal unit. If the actual marginal unit has short run marginal costs that would cause it to be inframarginal, a new unit would be marginal. If the offer of that new unit were greater than the cost of the original marginal unit, the markup impact would be lower than the MMU measure. If the newly marginal unit is on a price-based schedule, the analysis would have to capture the markup impact of that unit as well.

The MMU calculated an explicit measure of the impact of marginal unit markups on LMP. The markup impact includes the impact of the identified markup conduct on a unit by unit basis, but the inclusion of negative markup impacts has an offsetting effect. The markup analysis does not distinguish between intervals in which a unit has local market power or has a price impact in an unconstrained interval. The markup analysis is a more general measure of the competitiveness of the energy market.

Real-Time Markup

Markup Component of Real-Time Price by Fuel, Unit Type

The markup component of price is the difference between the system price, when the system price is determined by the active offers of the marginal units, whether price or cost-based, and the system price, based on the cost-based offers of those marginal units.

Table 3-49 shows the average unit markup component of LMP for marginal units, by unit type and primary fuel. The markup component of LMP is a measure of the impact of the markups of marginal units shown in Table 3-49 on the system-wide load-weighted LMP. The negative markup components of LMP reflect the negative markups shown in the Table 3-28.

All generating units, including coal units, are allowed to include a 10 percent adder in their cost offer. The 10 percent adder was included in the definition of cost offers prior to the implementation of PJM markets in 1999, based on the uncertainty of calculating the hourly operating costs of CTs under changing ambient conditions. Coal units do not face the same cost uncertainty as gas-fired CTs. A review of actual participant behavior supports this view, as the owners of coal units, facing competition, typically exclude the 10 percent adder from their actual offers. The unadjusted markup is calculated as the difference between the price offer and the cost offer including the 10 percent adder in the cost offer. The adjusted markup is calculated as the difference between the price offer and the cost offer excluding the 10 percent adder from the cost offer. Even the adjusted markup underestimates the markup because coal units facing increased competitive pressure have excluded both the ten percent adder and some or all components of operating and maintenance cost. While both these elements are permitted under the definition of cost-based offers in the relevant PJM manual, they are not part of a competitive offer for a coal unit because they are not actually short run marginal costs, and market behavior reflected that fact.[57]

In order to accurately assess the markup behavior of market participants, real-time and day-ahead LMPs are decomposed using two different approaches. In the first approach, markup is the difference between the active offer of the marginal unit and the cost offer. In the second approach, the 10 percent markup is removed from the cost offers of coal units because coal units do not face the same cost uncertainty as gas fired CTs. The adjusted markup is calculated as the difference between the active offer and the cost offer excluding the 10 percent adder. The unadjusted markup is calculated as the

57 See PJM. "Manual 15: Cost Development Guidelines," Revision 27 (April 20, 2016).

difference between the active offer and the cost offer including the 10 percent adder in the cost offer.

Table 3-49 shows the mark-up component of the load-weighted LMP by fuel type and unit type using unadjusted and adjusted offers. The adjusted markup component of LMP decreased from $2.20 in the first six months of 2015 to $0.97 in the first six months of 2016. The adjusted markup contribution of coal units in the first six months of 2016 was -$0.55. The adjusted mark-up component of all gas-fired units in the first six months of 2016 was $1.59, an increase of $0.41 from the first six months of 2015. The markup component of wind units was $0.05. If a price-based offer is negative, but less negative than a cost-based offer, the markup is positive. In the first six months of 2016, among the wind units that were marginal, 2.98 percent had positive offer prices.

Table 3-49 Markup component of the overall PJM real-time, load-weighted, average LMP by primary fuel type and unit type: January through June, 2015 and 2016[58]

		2015 (Jan-Jun)		2016 (Jan-Jun)	
Fuel Type	Unit Type	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)
Coal	Steam	($0.96)	$0.79	($2.05)	($0.55)
Gas	CC	$1.21	$1.21	$1.18	$1.18
Gas	CT	($0.02)	($0.02)	$0.16	$0.16
Gas	Diesel	$0.01	$0.01	$0.00	$0.00
Gas	Steam	($0.01)	($0.01)	$0.24	$0.24
Municipal Waste	Steam	($0.02)	($0.02)	$0.00	$0.00
Oil	CC	$0.09	$0.09	$0.00	$0.00
Oil	CT	$0.06	$0.06	$0.01	$0.01
Oil	Diesel	$0.01	$0.01	$0.00	$0.00
Oil	Steam	$0.04	$0.04	$0.00	$0.00
Other	Steam	$0.03	$0.03	($0.12)	($0.12)
Uranium	Steam	$0.00	$0.00	$0.00	$0.00
Wind	Wind	$0.03	$0.03	$0.05	$0.05
Total		$0.46	$2.20	($0.53)	$0.97

Markup Component of Real-Time Price

Table 3-50 shows the markup component, calculated using unadjusted offers, of average prices and of average monthly on-peak and off-peak prices. Table 3-51 shows the markup component, calculated using adjusted offers, of average prices and of average monthly on-peak and off-peak prices. In the first six months of 2016, when using unadjusted cost offers, -$0.53 per MWh of the PJM real-time load-weighted average LMP was attributable to markup. Using adjusted cost offers, $0.97 per MWh of the PJM real-time load-weighted average LMP was attributable to markup. In the first six months of 2016, the peak markup component was highest in April, $1.74 per MWh using unadjusted cost offers and $3.50 per MWh using adjusted cost offers. This corresponds to 5.27 percent and 10.58 percent of the real-time load-weighted average LMP in April.

Table 3-50 Monthly markup components of real-time load-weighted LMP (Unadjusted): January through June, 2015 and 2016

	2015			2016		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
Jan	($1.42)	($2.62)	($0.15)	($1.65)	($1.56)	($1.74)
Feb	$4.62	$1.72	$7.46	($1.06)	($0.84)	($1.26)
Mar	$1.84	$1.82	$1.86	($0.35)	($1.22)	$0.42
Apr	($0.42)	($0.69)	($0.18)	$0.45	($0.90)	$1.74
May	($1.85)	($3.59)	($0.01)	($1.20)	($1.14)	($1.26)
Jun	($0.43)	($1.20)	$0.21	$0.81	$0.62	$0.97
Total	$0.46	($0.76)	$1.63	($0.53)	($0.86)	($0.21)

58 The Unit Type Diesel refers to power generation using reciprocating internal combustion engines. Such Diesel units can use a variety of fuel types including diesel, natural gas, oil and gas from municipal waste.

Table 3-51 Monthly markup components of real-time load-weighted LMP (Adjusted): January through June, 2015 and 2016

	2015			2016		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
Jan	$0.61	($0.61)	$1.90	($0.01)	($0.13)	$0.12
Feb	$6.44	$3.57	$9.24	$0.53	$0.58	$0.48
Mar	$3.71	$3.69	$3.74	$0.97	$0.01	$1.82
Apr	$1.22	$0.72	$1.65	$2.08	$0.61	$3.50
May	($0.45)	($2.41)	$1.64	$0.27	($0.06)	$0.60
Jun	$1.18	$0.06	$2.10	$2.17	$1.65	$2.60
Total	$2.20	$0.87	$3.48	$0.97	$0.43	$1.50

Hourly Markup Component of Real-Time Prices

Figure 3-32 shows the markup contribution to the hourly load-weighted LMP using unadjusted cost offers for the first six months of 2016 and 2015. Figure 3-33 shows the markup contribution to the hourly load-weighted LMP using adjusted cost offers for the first six months of 2016 and 2015. In 2015, high markups were seen during the cold winter days observed in February and March. In contrast, the first six months of 2016 had low markups.

Figure 3-32 Markup contribution to real-time hourly load-weighted LMP (Unadjusted): January through June, 2015 and 2016

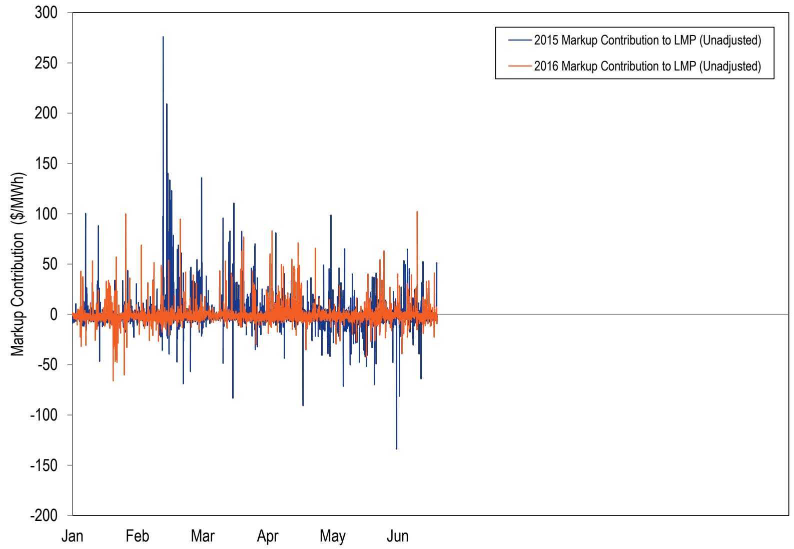
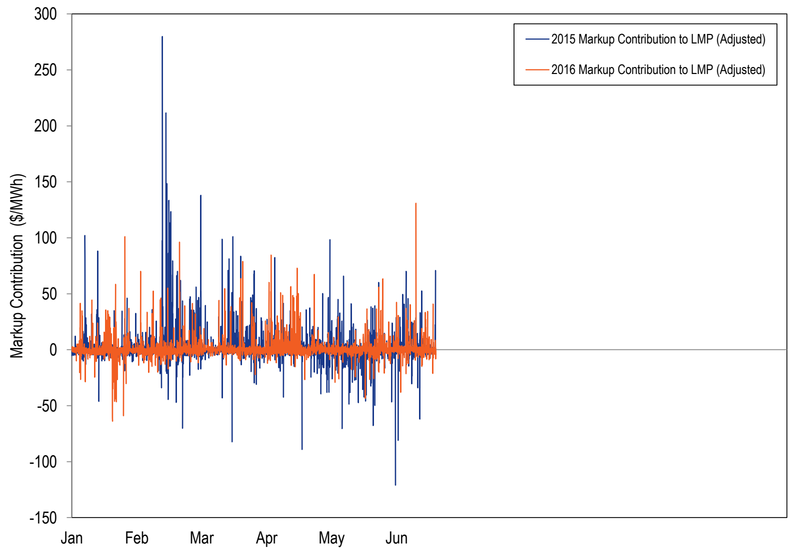


Figure 3-33 Markup contribution to real-time hourly load-weighted LMP (Adjusted): January through June, 2015 and 2016



Markup Component of Real-Time Zonal Prices

The unit markup component of average real-time price using unadjusted offers is shown for each zone for the first six months of 2015 and the first six months of 2016 in Table 3-52 and for adjusted offers in Table 3-53. The smallest zonal all hours average markup component using unadjusted offers for the first six month of 2016 was in the BGE Zone, -$2.22 per MWh, while the highest was in the RECO Control Zone, $0.87 per MWh. The smallest zonal on peak average markup was in the BGE Control Zone, -$1.85 per MWh, while the highest was in the RECO Control Zone, $1.42 per MWh.

Table 3-52 Average real-time zonal markup component (Unadjusted): January through June, 2015 and 2016

	2015 (Jan-Jun)			2016 (Jan-Jun)		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
AECO	$0.11	($1.27)	$1.47	$0.67	$0.32	$1.02
AEP	$0.02	($1.29)	$1.30	($0.81)	($1.24)	($0.40)
APS	$0.96	($0.14)	$2.04	($0.84)	($1.22)	($0.47)
ATSI	$0.20	($1.14)	$1.48	($0.77)	($1.23)	($0.32)
BGE	$1.75	$1.01	$2.48	($2.22)	($2.59)	($1.85)
ComEd	($0.01)	($1.52)	$1.39	($0.59)	($0.69)	($0.50)
DAY	$0.26	($1.28)	$1.71	($0.97)	($1.27)	($0.70)
DEOK	$0.21	($1.51)	$1.86	($0.90)	($1.21)	($0.62)
DLCO	($0.05)	($1.30)	$1.13	($0.63)	($1.19)	($0.10)
DPL	$0.34	($0.78)	$1.44	$0.59	$0.31	$0.85
Dominion	$1.09	$0.29	$1.87	($1.23)	($1.38)	($1.08)
EKPC	$0.15	($1.55)	$1.91	($0.96)	($1.03)	($0.89)
JCPL	($0.06)	($1.13)	$0.93	$0.85	$0.43	$1.23
Met-Ed	$0.18	($1.01)	$1.30	$0.79	$0.32	$1.22
PECO	($0.00)	($1.02)	$0.96	$0.81	$0.43	$1.16
PENELEC	$0.74	($0.59)	$2.00	($0.14)	($0.69)	$0.37
PPL	$0.53	($0.79)	$1.78	$0.75	$0.26	$1.21
PSEG	$0.72	($0.68)	$2.03	$0.79	$0.42	$1.14
Pepco	$1.47	$0.57	$2.32	($1.61)	($1.89)	($1.36)
RECO	$1.14	($1.09)	$3.08	$0.87	$0.24	$1.42

Table 3-53 Average real-time zonal markup component (Adjusted): January through June, 2015 and 2016

	2015 (Jan-Jun)			2016 (Jan-Jun)		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
AECO	$1.41	$0.02	$2.79	$1.37	$0.95	$1.79
AEP	$1.85	$0.39	$3.27	$0.83	$0.18	$1.46
APS	$2.80	$1.59	$4.00	$0.83	$0.23	$1.42
ATSI	$2.09	$0.60	$3.50	$0.80	$0.15	$1.42
BGE	$4.12	$3.16	$5.05	$0.53	($0.20)	$1.24
ComEd	$1.59	($0.07)	$3.12	$0.88	$0.51	$1.23
DAY	$2.14	$0.41	$3.76	$0.72	$0.17	$1.23
DEOK	$2.02	$0.13	$3.83	$0.73	$0.19	$1.25
DLCO	$1.79	$0.40	$3.10	$0.90	$0.15	$1.61
DPL	$1.73	$0.63	$2.83	$1.31	$0.97	$1.65
Dominion	$3.10	$2.16	$4.03	$0.76	$0.30	$1.21
EKPC	$1.97	$0.17	$3.83	$0.74	$0.41	$1.08
JCPL	$1.20	$0.13	$2.19	$1.62	$1.10	$2.11
Met-Ed	$1.52	$0.27	$2.68	$1.53	$0.95	$2.07
PECO	$1.28	$0.28	$2.23	$1.49	$1.05	$1.91
PENELEC	$2.45	$1.00	$3.82	$1.12	$0.43	$1.76
PPL	$1.84	$0.51	$3.10	$1.54	$0.94	$2.10
PSEG	$2.16	$0.70	$3.52	$1.57	$1.07	$2.04
Pepco	$3.64	$2.54	$4.67	$0.66	$0.05	$1.23
RECO	$2.78	$0.52	$4.74	$1.71	$0.94	$2.38

Markup by Real Time Price Levels

Table 3-54 shows the average markup component of observed prices, based on the unadjusted cost-based offers and adjusted cost-based offers of the marginal units, when the PJM average LMP was in the identified price range.

Table 3-54 Average real-time markup component (By price category, unadjusted): January through June, 2015 and 2016

	2015 (Jan-Jun)		2016 (Jan-Jun)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	$0.46	100.0%	($1.15)	63.9%
$25 to $50	$0.00	0.0%	($0.37)	31.9%
$50 to $75	$0.00	0.0%	$0.54	2.9%
$75 to $100	$0.00	0.0%	$0.29	0.8%
$100 to $125	$0.00	0.0%	$0.09	0.4%
$125 to $150	$0.00	0.0%	$0.04	0.1%
>= $150	$0.00	0.0%	$0.03	0.1%

Table 3-55 Average real-time markup component (By price category, adjusted): January through June, 2015 and 2016

	2015 (Jan-Jun)		2016 (Jan-Jun)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	$2.22	100.0%	($0.38)	63.9%
$25 to $50	$0.00	0.0%	$0.32	31.9%
$50 to $75	$0.00	0.0%	$0.57	2.9%
$75 to $100	$0.00	0.0%	$0.29	0.8%
$100 to $125	$0.00	0.0%	$0.10	0.4%
$125 to $150	$0.00	0.0%	$0.04	0.1%
>= $150	$0.00	0.0%	$0.03	0.1%

Day-Ahead Markup

Markup Component of Day-Ahead Price by Fuel, Unit Type

The markup component of the PJM day-ahead, load-weighted average LMP by primary fuel and unit type is shown in Table 3-56. INC, DEC and up to congestion transactions have zero markups. Up to congestion transactions were 83.3 percent of marginal resources, INCs were 3.8 percent of marginal resources, and DECs were 7.3 percent of marginal resources in the first six months of 2016. The share of marginal up to congestion transactions decreased significantly beginning on September 8, 2014, as a result of the FERC's UTC uplift refund notice which became effective on September 8, 2014.[59] The adjusted markup of coal units is calculated as the difference between the price

59 See 18 CFR § 385.213 (2014).

offer, and the cost offer excluding the 10 percent adder. Table 3-56 shows the markup component of LMP for marginal generating resources. Generating resources were only 5.5 percent of marginal resources in the first six months of 2016. The markup component of LMP for marginal generating resources increased in coal-fired steam units and decreased in oil-fired CT units. The markup component of LMP for coal units increased from $0.63 in the first six months of 2015 to $1.29 in the first six months of 2016 using adjusted offers. The markup component of LMP for gas-fired CCs increased from -$0.03 in the first six months of 2015 to $0.00 in the first six months of 2016 using adjusted offers.

Table 3-56 Markup component of the annual PJM day-ahead, load-weighted, average LMP by primary fuel type and unit type: January through June, 2015 and 2016

		2015 (Jan - Jun)		2016 (Jan - Jun)	
Fuel Type	Unit Type	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)
Coal	Steam	($0.37)	$0.63	$0.37	$1.29
Gas	CC	($0.03)	($0.03)	$0.00	$0.00
Gas	CT	$0.11	$0.11	$0.03	$0.03
Gas	Diesel	$0.05	$0.05	$0.00	$0.00
Gas	Steam	$0.08	$0.08	$0.30	$0.30
Municipal Waste	Steam	($0.00)	($0.00)	$0.02	$0.02
Oil	CC	$0.07	$0.07	$0.00	$0.00
Oil	CT	$0.03	$0.03	($0.01)	($0.01)
Oil	Diesel	$0.00	$0.00	$0.00	$0.00
Oil	Steam	$0.14	$0.14	($0.33)	($0.33)
Other	Steam	($0.00)	($0.00)	($0.00)	($0.00)
Uranium	Steam	$0.00	$0.00	($0.01)	($0.01)
Wind	Wind	$0.03	$0.03	$0.01	$0.01
Total		$0.09	$1.09	$0.38	$1.29

Markup Component of Day-Ahead Price

The markup component of price is the difference between the system price, when the system price is determined by the active offers of the marginal units, whether price or cost-based, and the system price, based on the cost-based offers of those marginal units. Only hours when generating units were marginal on either priced-based offers or on cost-based offers were included in the markup calculation.

Table 3-57 shows the markup component of average prices and of average monthly on-peak and off-peak prices using unadjusted offers. Table 3-58 shows the markup component of average prices and of average monthly on-peak and off-peak prices using adjusted offers. In the first six months of 2016, when using adjusted cost-offers, $1.29 per MWh of the PJM day-ahead load-weighted average LMP was attributable to markup. In the first six months of 2016, the peak markup component was highest in January, $3.52 per MWh using adjusted cost offers. Using adjusted cost offers, the markup component in the first six months of 2016 decreased in every month except January, March and April from the first six months of 2015. Using adjusted cost offers, the markup component increased from -$0.29 to $2.26 in January.

Table 3-57 Monthly markup components of day-ahead (Unadjusted), load-weighted LMP: January through June, 2015 and 2016

	2015			2016		
	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
Jan	($1.98)	($1.27)	($2.66)	$1.12	$2.50	($0.11)
Feb	$1.39	$3.35	($0.62)	$0.20	$0.99	($0.65)
Mar	($0.43)	$0.49	($1.38)	$0.23	$1.11	($0.78)
Apr	($0.79)	($0.06)	($1.63)	$0.30	$1.42	($0.87)
May	$0.75	$0.70	$0.80	($0.28)	($0.12)	($0.45)
Jun	$1.66	$2.32	$0.85	$0.53	$1.95	($1.20)
Annual	$0.09	$0.97	($0.83)	$0.38	$1.35	($0.65)

Table 3-58 Monthly markup components of day-ahead (Adjusted), load-weighted LMP: January through June, 2015 and 2016

	2015			2016		
	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
Jan	($0.29)	$0.21	($0.76)	$2.26	$3.52	$1.13
Feb	$2.81	$4.51	$1.06	$1.20	$2.01	$0.35
Mar	$1.01	$1.79	$0.21	$1.16	$2.03	$0.17
Apr	$0.50	$1.03	($0.11)	$1.11	$2.02	$0.17
May	$0.75	$0.70	$0.80	$0.49	$0.59	$0.38
Jun	$1.66	$2.32	$0.85	$1.32	$2.71	($0.37)
Annual	$1.09	$1.82	$0.32	$1.29	$2.20	$0.34

Markup Component of Day-Ahead Zonal Prices

The markup component of annual average day-ahead price using unadjusted offers is shown for each zone in Table 3-59. The markup component of annual average day-ahead price using adjusted offers is shown for each zone in Table 3-60. Using unadjusted offers, the markup component of the average day-ahead price increased in all zones from the first six months of 2015 to the first six months of 2016 except AECO, DPL, JCPL, PECO, PSEG and RECO control zones. The smallest zonal all hours average markup component using adjusted offers for the first six months of 2016 was in the ComEd Zone, $1.06 per MWh, while the highest was in the DPL Control Zone, $1.70 per MWh. The smallest zonal on peak average markup using adjusted offers was in the ComEd Control Zone, $1.89 per MWh, while the highest was in the DPL Control Zone, $2.63 per MWh.

Table 3-59 Day-ahead, average, zonal markup component (Unadjusted): January through June, 2015 and 2016

	2015 (Jan - Jun)			2016 (Jan - Jun)		
	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
AECO	$1.79	$3.94	($0.48)	$0.63	$1.74	($0.55)
AEP	$0.00	$1.06	($1.07)	$0.26	$1.18	($0.69)
AP	($0.21)	$0.23	($0.65)	$0.34	$1.30	($0.64)
ATSI	($0.38)	$0.42	($1.24)	$0.29	$1.19	($0.67)
BGE	($0.78)	($0.79)	($0.77)	$0.38	$1.43	($0.73)
ComEd	$0.01	$1.15	($1.23)	$0.15	$1.04	($0.83)
DAY	($0.28)	$0.87	($1.52)	$0.25	$1.14	($0.71)
DEOK	($0.22)	$0.81	($1.31)	$0.21	$1.09	($0.72)
DLCO	($0.78)	($0.25)	($1.34)	$0.33	$1.25	($0.66)
Dominion	$0.02	$0.36	($0.33)	$0.49	$1.46	($0.50)
DPL	$1.24	$2.99	($0.55)	$0.96	$1.95	($0.05)
EKPC	($0.02)	$1.11	($1.13)	$0.28	$1.15	($0.59)
JCPL	$1.01	$2.42	($0.56)	$0.68	$1.72	($0.48)
Met-Ed	$0.43	$1.28	($0.48)	$0.52	$1.59	($0.64)
PECO	$0.75	$1.91	($0.49)	$0.61	$1.71	($0.56)
PENELEC	$0.02	$0.71	($0.69)	$0.29	$1.21	($0.64)
Pepco	($0.05)	$0.52	($0.64)	$0.34	$1.41	($0.78)
PPL	$0.54	$1.61	($0.59)	$0.57	$1.67	($0.60)
PSEG	$0.95	$2.29	($0.52)	$0.64	$1.76	($0.61)
RECO	$0.85	$2.06	($0.55)	$0.53	$1.59	($0.68)

Table 3-60 Day-ahead, average, zonal markup component (Adjusted): January through June, 2015 and 2016

	2015 (Jan - Jun)			2016 (Jan - Jun)		
	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
AECO	$2.61	$4.61	$0.50	$1.35	$2.43	$0.21
AEP	$1.09	$1.97	$0.18	$1.22	$2.05	$0.37
AP	$0.83	$1.14	$0.51	$1.32	$2.19	$0.42
ATSI	$0.75	$1.41	$0.05	$1.25	$2.06	$0.38
BGE	$0.28	$0.11	$0.46	$1.48	$2.46	$0.45
ComEd	$1.08	$2.10	($0.02)	$1.06	$1.89	$0.16
DAY	$0.83	$1.81	($0.23)	$1.24	$2.04	$0.37
DEOK	$0.85	$1.73	($0.07)	$1.17	$1.95	$0.33
DLCO	$0.31	$0.69	($0.10)	$1.28	$2.11	$0.38
Dominion	$0.99	$1.19	$0.79	$1.48	$2.40	$0.55
DPL	$2.06	$3.63	$0.45	$1.70	$2.63	$0.74
EKPC	$1.08	$2.02	$0.16	$1.25	$2.00	$0.49
JCPL	$1.85	$3.11	$0.44	$1.44	$2.43	$0.33
Met-Ed	$1.27	$1.98	$0.51	$1.29	$2.32	$0.18
PECO	$1.56	$2.58	$0.47	$1.36	$2.40	$0.25
PENELEC	$0.95	$1.47	$0.43	$1.17	$2.02	$0.30
Pepco	$0.97	$1.41	$0.50	$1.37	$2.37	$0.33
PPL	$1.41	$2.33	$0.43	$1.34	$2.39	$0.22
PSEG	$1.75	$2.94	$0.45	$1.37	$2.44	$0.18
RECO	$1.65	$2.72	$0.41	$1.26	$2.28	$0.09

Markup by Day-Ahead Price Levels

Table 3-61 and Table 3-62 show the average markup component of observed prices, based on the unadjusted cost-based offers and adjusted cost-based offers of the marginal units, when the PJM system LMP was in the identified price range.

Table 3-61 Average, day-ahead markup (By LMP category, unadjusted): January through June, 2015 and 2016

	2015 (Jan - Jun)		2016 (Jan - Jun)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	($0.68)	17.9%	($1.07)	51.2%
$25 to $50	($0.38)	66.2%	$1.37	47.3%
$50 to $75	$1.72	7.6%	$4.59	1.4%
$75 to $100	($3.54)	4.0%	$5.20	0.1%
$100 to $125	$1.12	2.1%	$0.00	0.0%
$125 to $150	$10.26	0.9%	$0.00	0.0%
>= $150	$13.21	1.3%	$0.00	0.0%

Table 3-62 Average, day-ahead markup (By LMP category, adjusted): January through June, 2015 and 2016

	2015 (Jan - Jun)		2016 (Jan - Jun)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	($0.04)	17.9%	$0.10	51.2%
$25 to $50	$0.90	66.2%	$2.29	47.3%
$50 to $75	$2.45	7.6%	$4.96	1.4%
$75 to $100	($2.87)	4.0%	$5.20	0.1%
$100 to $125	$1.80	2.1%	$0.00	0.0%
$125 to $150	$10.93	0.9%	$0.00	0.0%
>= $150	$13.60	1.3%	$0.00	0.0%

Prices

The conduct of individual market entities within a market structure is reflected in market prices. PJM locational marginal prices (LMPs) are a direct measure of market performance. Price level is a good, general indicator of market performance, although overall price results must be interpreted carefully because of the multiple factors that affect them. Among other things, overall average prices reflect changes in supply and demand, generation fuel mix, the cost of fuel, emission related expenses, markup and local price differences caused by congestion. PJM also may administratively set prices with the creation of a closed loop interface related to demand side resources or reactive power.

Real-time and day-ahead energy market load-weighted prices were 36.0 percent and 44.7 percent lower in the first six months of 2016 than in the first six months of 2015 as a result of lower fuel costs and lower demand in 2016. Coal and natural gas prices decreased in 2016. Comparing fuel prices in the first six months of 2016 to the first six months of 2015, the price of Northern Appalachian coal was 23.5 percent lower; the price of Central Appalachian coal was 16.7 percent lower; the price of Powder River Basin coal was 12.7 percent lower; the price of eastern natural gas was 56.8 percent lower; and the price of western natural gas was 25.4 percent lower.

PJM real-time energy market prices decreased in the first six months of 2016 compared to the first six months of 2015. The average LMP was 33.5 percent lower in the first six months of 2016 than in the first six months of 2015, $25.84 per MWh versus $38.87 per MWh. The load-weighted average LMP was 36.0 percent lower in the first six months of 2016 than in the first six months of 2015, $27.09 per MWh versus $42.30 per MWh.

The fuel-cost adjusted, load-weighted, average LMP in the first six months of 2016 was 18.8 percent higher than the load-weighted, average LMP for the first six months of 2016. If fuel and emission costs in the first six months of 2016 had been the same as in the first six months of 2015, holding everything else constant, the load-weighted LMP would have been higher, $32.17 per MWh instead of the observed $27.09 per MWh.

PJM day-ahead energy market prices decreased in the first six months of 2016 compared to the first six months of 2015. The average LMP was 34.4 percent lower in the first six months of 2016 than in the first six months of 2015, $26.24 per MWh versus $39.98 per MWh. The day-ahead load-weighted average LMP was 36.8 percent lower in the first six months of 2016 than in the first six months of 2015, $27.33 per MWh versus $43.26 per MWh.

Occasionally, in a constrained market, the LMPs at some pricing nodes can exceed the offer price of the highest cleared generator in the supply stack.[60] In the nodal pricing system, the LMP at a pricing node is the total cost of meeting incremental demand at that node. When there are binding transmission constraints, satisfying the marginal increase in demand at a node may require increasing the output of some generators while simultaneously decreasing the output of other generators, such that the transmission constraints are not violated. The total cost of redispatching multiple generators can at times exceed the cost of marginally increasing the output of the most expensive generator offered. Thus the LMPs at some pricing nodes exceed $1,000 per MWh, the cap on the generators' offer price in the PJM market.[61]

Real-Time LMP

Real-time average LMP is the hourly average LMP for the PJM Real-Time Energy Market.[62]

Real-Time Average LMP

PJM Real-Time Average LMP Duration

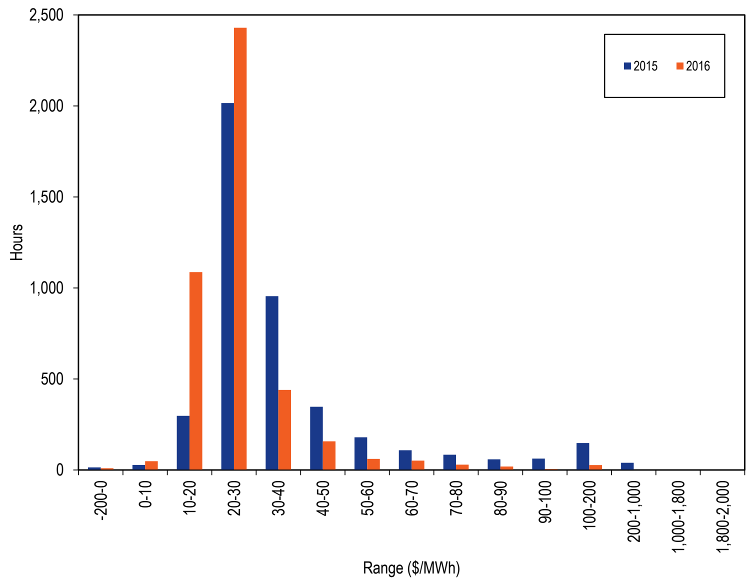
Figure 3-34 shows the hourly distribution of PJM real-time average LMP for the first six months of 2015 and 2016.

60 See O'Neill R. P, Mead D. and Malvadkar P. "On Market Clearing Prices Higher than the Highest Bid and Other Almost Paranormal Phenomena." *The Electricity Journal 2005*; 18(2): pp 19-27.

61 The offer cap in PJM was temporarily increased to $1,800 per MWh prior to the winter of 2014/2015. A new cap of $2,000 per MWh, only for offers with costs exceeding $1,000 per MWh, went into effect on December, 14, 2015, 153 FERC ¶ 61,289 (2015).

62 See the *MMU Technical Reference for the PJM Markets*, at "Calculating Locational Marginal Price," for detailed definition of Real-Time LMP. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

Figure 3-34 Average LMP for the PJM Real-Time Energy Market: January through June, 2015 and 2016



PJM Real-Time, Average LMP

Table 3-63 shows the PJM real-time, average LMP for the first six months of each year from 1998 through 2016.[63]

Table 3-63 PJM real-time, average LMP (Dollars per MWh): January through June, 1998 through 2016

	Real-Time LMP			Year-to-Year Change		
Jan-Jun	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$20.13	$15.90	$15.59	NA	NA	NA
1999	$22.94	$17.84	$41.16	14.0%	12.2%	164.0%
2000	$25.38	$18.03	$25.65	10.6%	1.1%	(37.7%)
2001	$33.10	$25.69	$21.11	30.4%	42.5%	(17.7%)
2002	$24.10	$19.64	$13.21	(27.2%)	(23.6%)	(37.4%)
2003	$41.31	$33.74	$27.81	71.4%	71.8%	110.6%
2004	$44.99	$40.75	$22.97	8.9%	20.8%	(17.4%)
2005	$45.71	$39.80	$23.51	1.6%	(2.3%)	2.3%
2006	$49.36	$43.46	$25.26	8.0%	9.2%	7.5%
2007	$55.03	$48.05	$31.42	11.5%	10.6%	24.4%
2008	$70.19	$59.53	$41.77	27.6%	23.9%	33.0%
2009	$40.12	$35.42	$19.30	(42.8%)	(40.5%)	(53.8%)
2010	$43.27	$37.11	$22.20	7.9%	4.8%	15.0%
2011	$45.51	$37.40	$32.52	5.2%	0.8%	46.5%
2012	$29.74	$28.32	$16.10	(34.6%)	(24.3%)	(50.5%)
2013	$36.56	$32.79	$17.18	22.9%	15.8%	6.7%
2014	$62.14	$39.69	$88.87	69.9%	21.0%	417.4%
2015	$38.87	$29.04	$34.04	(37.4%)	(26.8%)	(61.7%)
2016	$25.84	$23.17	$13.61	(33.5%)	(20.2%)	(60.0%)

Real-Time, Load-Weighted, Average LMP

Higher demand (load) generally results in higher prices, all else constant. As a result, load-weighted, average prices are generally higher than average prices. Load-weighted LMP reflects the average LMP paid for actual MWh consumed during a year. Load-weighted, average LMP is the average of PJM hourly LMP, each weighted by the PJM total hourly load. The real-time, load-weighted, average LMP decreased by 36.0 percent compared to the first six months of 2015.

63 The system average LMP is the average of the hourly LMP without any weighting. The only exception is that market-clearing prices (MCPs) are included for January to April 1998. MCP was the single market-clearing price calculated by PJM prior to implementation of LMP.

PJM Real-Time, Load-Weighted, Average LMP

Table 3-64 shows the PJM real-time, load-weighted, average LMP for the first six months of each year from 1998 through 2016.

Table 3-64 PJM real-time, load-weighted, average LMP (Dollars per MWh): January through June, 1998 through 2016

	Real-Time, Load-Weighted, Average LMP			Year-to-Year Change		
Jan-Jun	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$21.66	$16.80	$18.39	NA	NA	NA
1999	$25.34	$18.59	$52.06	17.0%	10.7%	183.1%
2000	$27.76	$18.91	$29.69	9.5%	1.7%	(43.0%)
2001	$35.27	$27.88	$22.12	27.0%	47.4%	(25.5%)
2002	$25.93	$20.67	$14.62	(26.5%)	(25.9%)	(33.9%)
2003	$44.43	$37.98	$28.55	71.4%	83.8%	95.2%
2004	$47.62	$43.96	$23.30	7.2%	15.8%	(18.4%)
2005	$48.67	$42.30	$24.81	2.2%	(3.8%)	6.5%
2006	$51.83	$45.79	$26.54	6.5%	8.3%	7.0%
2007	$58.32	$52.52	$32.39	12.5%	14.7%	22.1%
2008	$74.77	$64.26	$44.25	28.2%	22.4%	36.6%
2009	$42.48	$36.95	$20.61	(43.2%)	(42.5%)	(53.4%)
2010	$45.75	$38.78	$23.60	7.7%	5.0%	14.5%
2011	$48.47	$38.63	$37.59	5.9%	(0.4%)	59.3%
2012	$31.21	$28.98	$17.69	(35.6%)	(25.0%)	(52.9%)
2013	$37.96	$33.58	$18.54	21.6%	15.9%	4.8%
2014	$69.92	$42.61	$103.35	84.2%	26.9%	457.6%
2015	$42.30	$30.34	$37.85	(39.5%)	(28.8%)	(63.4%)
2016	$27.09	$23.82	$14.49	(36.0%)	(21.5%)	(61.7%)

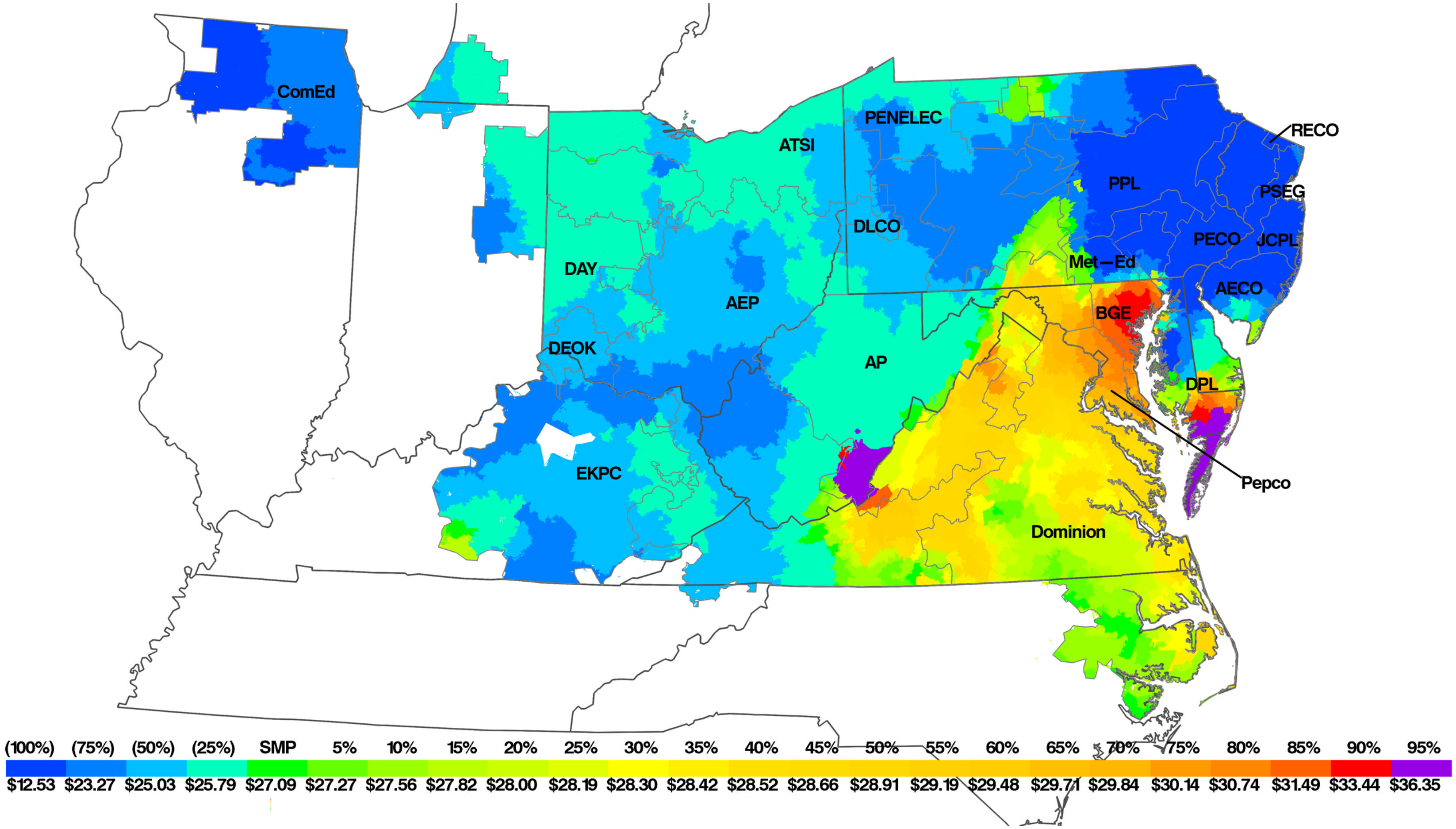
Table 3-65 shows zonal real-time, and real-time, load-weighted, average LMP for the first six months of 2015 and 2016.

Table 3-65 Zone real-time and real-time, load-weighted, average LMP (Dollars per MWh): January through June, 2015 and 2016

	Real-Time Average LMP			Real-Time, Load-Weighted, Average LMP		
Zone	2015 (Jan-Jun)	2016 (Jan-Jun)	Percent Change	2015 (Jan-Jun)	2016 (Jan-Jun)	Percent Change
AECO	$41.58	$23.53	(43.4%)	$45.10	$25.12	(44.3%)
AEP	$35.25	$26.03	(26.1%)	$37.76	$27.09	(28.3%)
AP	$40.67	$26.60	(34.6%)	$44.73	$27.84	(37.8%)
ATSI	$35.82	$26.07	(27.2%)	$37.75	$27.05	(28.3%)
BGE	$48.89	$34.12	(30.2%)	$54.57	$36.27	(33.5%)
ComEd	$29.91	$23.59	(21.2%)	$31.54	$24.66	(21.8%)
Day	$35.45	$26.11	(26.3%)	$37.79	$27.18	(28.1%)
DEOK	$34.15	$25.30	(25.9%)	$36.50	$26.34	(27.8%)
DLCO	$33.23	$25.46	(23.4%)	$34.87	$26.50	(24.0%)
Dominion	$43.48	$28.90	(33.5%)	$49.19	$30.77	(37.4%)
DPL	$44.95	$25.47	(43.3%)	$52.35	$27.61	(47.3%)
EKPC	$32.82	$25.20	(23.2%)	$36.36	$26.40	(27.4%)
JCPL	$41.20	$22.50	(45.4%)	$45.14	$24.08	(46.6%)
Met-Ed	$41.09	$22.43	(45.4%)	$45.80	$23.71	(48.2%)
PECO	$40.41	$22.01	(45.5%)	$44.65	$23.37	(47.7%)
PENELEC	$40.07	$24.78	(38.2%)	$43.29	$25.72	(40.6%)
Pepco	$45.42	$30.67	(32.5%)	$50.34	$32.45	(35.5%)
PPL	$40.68	$22.48	(44.7%)	$46.09	$23.76	(48.4%)
PSEG	$44.83	$22.83	(49.1%)	$48.14	$24.15	(49.8%)
RECO	$45.63	$22.86	(49.9%)	$48.24	$24.45	(49.3%)
PJM	$42.30	$27.09	(36.0%)	$42.30	$27.09	(36.0%)

Figure 3-35 is a contour map of the real-time, load-weighted, average LMP in the first six months of 2016. In the legend, green represents the system marginal price (SMP) and each increment to the right and left of the SMP represents five percent of the pricing nodes above and below the SMP. The LMP for each five percent increment is the highest nodal average LMP for that set of nodes. Each increment to the left of the SMP is the lowest nodal average LMP for that set of nodes.

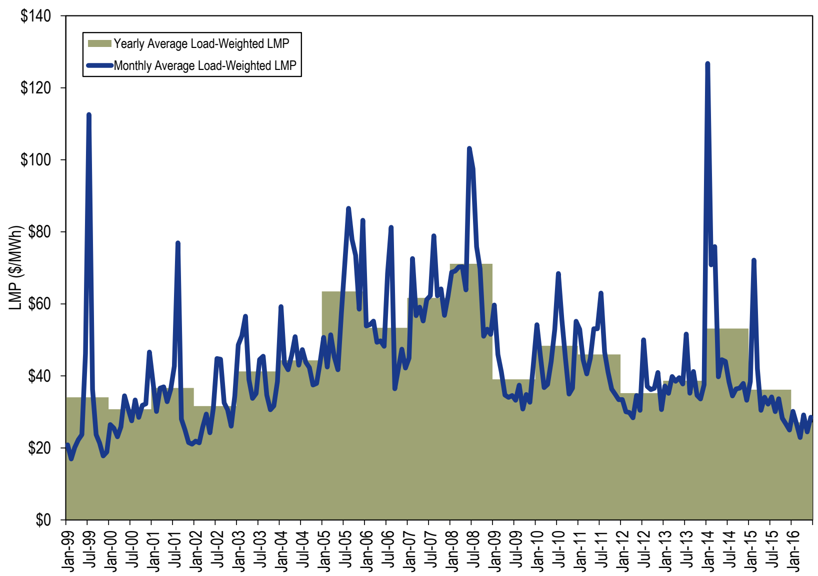
Figure 3-35 PJM real-time, load-weighted, average LMP: January through June, 2016



PJM Real-Time, Monthly, Load-Weighted, Average LMP

Figure 3-36 shows the PJM real-time monthly and annual load-weighted LMP for 1999 through 2015. PJM real-time monthly load-weighted average LMP in March 2016 was $22.90, which is the lowest real-time monthly load-weighted average LMP since February 2002 at $21.39.

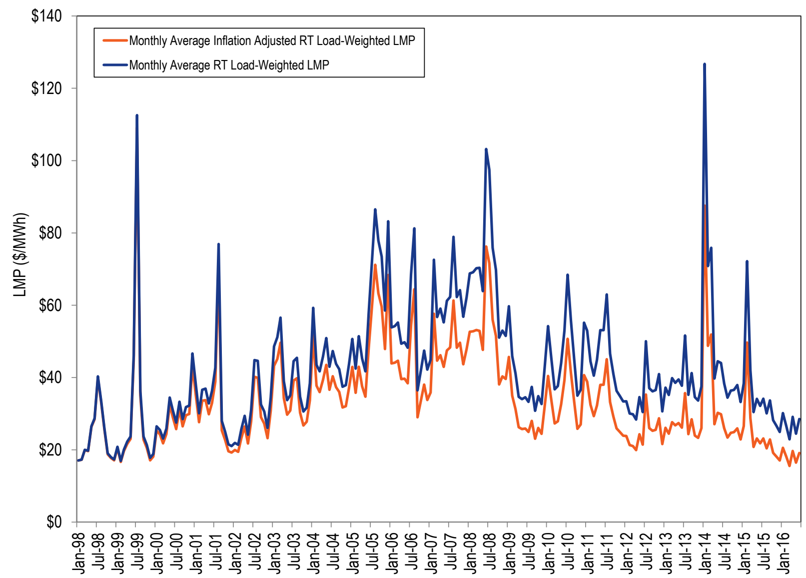
Figure 3-36 PJM real-time, monthly and annual, load-weighted, average LMP: 1999 through June 2016



PJM Real-Time, Monthly, Inflation Adjusted Load-Weighted, Average LMP

Figure 3-37 shows the PJM real-time monthly load-weighted average LMP and inflation adjusted monthly load-weighted average LMP for January 1998 through June 2016.[64] PJM real-time inflation adjusted monthly load-weighted average LMP in March 2016 was $15.54, which is the lowest real-time monthly load-weighted average real LMP observed since PJM real time markets started in 1998.

Figure 3-37 PJM real-time, monthly, load-weighted, average LMP and real time, monthly inflation adjusted load-weighted, average LMP: January 1998 through June 2016



Fuel Price Trends and LMP

Changes in LMP can result from changes in the marginal costs of marginal units, the units setting LMP. In general, fuel costs make up between 80 percent and 90 percent of marginal cost depending on generating technology, unit efficiency, unit age and other factors. The impact of fuel cost on marginal cost and on LMP depends on the fuel burned by marginal units and changes in fuel costs. Changes in emission allowance costs are another contributor to changes in the marginal cost of marginal units. Coal and natural gas prices decreased in 2016. Comparing fuel prices in the first six months of 2016 to the first six

64 To obtain the inflation adjusted monthly load-weighted average LMP, the PJM system-wide load-weighted average LMP is deflated using the US Consumer Price Index for all items, Urban Consumers (base period: January 1998), published by *Bureau of Labor Statistics.* <http://download.bls.gov/pub/time.series/cu/cu.data.1.AllItems> (July 15, 2016)

Energy Market

The PJM Energy Market comprises all types of energy transactions, including the sale or purchase of energy in PJM's Day-Ahead and Real-Time Energy Markets, bilateral and forward markets and self-supply. Energy transactions analyzed in this report include those in the PJM Day-Ahead and Real-Time Energy Markets. These markets provide key benchmarks against which market participants may measure results of transactions in other markets.

The Market Monitoring Unit (MMU) analyzed measures of market structure, participant conduct and market performance for the first six months of 2016, including market size, concentration, residual supply index, and price.[1] The MMU concludes that the PJM energy market results were competitive in the first six months of 2016.

Table 3-1 The energy market results were competitive

Market Element	Evaluation	Market Design
Market Structure: Aggregate Market	Competitive	
Market Structure: Local Market	Not Competitive	
Participant Behavior	Competitive	
Market Performance	**Competitive**	**Effective**

- The aggregate market structure was evaluated as competitive because the calculations for hourly HHI (Herfindahl-Hirschman Index) indicate that by the FERC standards, the PJM Energy Market in the first six months of 2016 was moderately concentrated. Average HHI was 1073 with a minimum of 837 and a maximum of 1356 in the first six months of 2016. The fact that the average HHI was in the moderately concentrated range does not mean that the aggregate market was competitive in all hours. It is possible to have an exercise of market power even when the average HHI is unconcentrated. The PJM Energy Market peaking segment of supply was highly concentrated.
- The local market structure was evaluated as not competitive due to the highly concentrated ownership of supply in local markets created by transmission constraints. The results of the three pivotal supplier (TPS) test, used to test local market structure, indicate the existence of market power in local markets created by transmission constraints. The local market performance is competitive as a result of the application of the TPS test. While transmission constraints create the potential for the exercise of local market power, PJM's application of the three pivotal supplier test identified local market power and resulted in offer capping to force competitive offers, correcting for structural issues created by local transmission constraints. There are, however, identified issues with the application of market power mitigation to resources whose owners fail the TPS test that need to be addressed.
- Participant behavior was evaluated as competitive because the analysis of markup shows that marginal units generally make offers at, or close to, their marginal costs in both Day-Ahead and Real-Time Energy Markets, although the behavior of some participants both routinely and during periods of high demand is consistent with economic withholding.
- Market performance was evaluated as competitive because market results in the energy market reflect the outcome of a competitive market, as PJM prices are set, on average, by marginal units operating at, or close to, their marginal costs in both Day-Ahead and Real-Time Energy Markets, although high markups during periods of high demand did affect prices.
- Market design was evaluated as effective because the analysis shows that the PJM Energy Market resulted in competitive market outcomes. In general, PJM's energy market design provides incentives for competitive behavior and results in competitive outcomes. In local markets, where market power is an issue, the market design identifies market power and causes the market to provide competitive market outcomes. The role of UTCs in the Day-Ahead Energy Market continues to cause concerns.

PJM markets are designed to promote competitive outcomes derived from the interaction of supply and demand in each of the PJM markets. Market design itself is the primary means of achieving and promoting competitive

1 Analysis of 2016 market results requires comparison to prior years. In 2004 and 2005, PJM conducted the phased integration of five control zones: ComEd, American Electric Power (AEP), The Dayton Power & Light Company (DAY), Duquesne Light Company (DLCO) and Dominion. In June 2011, PJM integrated the American Transmission Systems, Inc. (ATSI) Control Zone. In January 2012, PJM integrated the Duke Energy Ohio/Kentucky (DEOK) Control Zone. In June 2013, PJM integrated the Eastern Kentucky Power Cooperative (EKPC). By convention, control zones bear the name of a large utility service provider working within their boundaries. The nomenclature applies to the geographic area, not to any single company. For additional information on the control zones, the integrations, their timing and their impact on the footprint of the PJM service territory, see the *2015 State of the Market Report for PJM*, Appendix A, "PJM Geography."

outcomes in PJM markets. One of the MMU's primary goals is to identify actual or potential market design flaws.[2] The approach to market power mitigation in PJM has focused on market designs that promote competition (a structural basis for competitive outcomes) and on limiting market power mitigation to instances where the market structure is not competitive and thus where market design alone cannot mitigate market power. In the PJM Energy Market, this occurs primarily in the case of local market power. When a transmission constraint creates the potential for local market power, PJM applies a structural test to determine if the local market is competitive, applies a behavioral test to determine if generator offers exceed competitive levels and applies a market performance test to determine if such generator offers would affect the market price.[3] There are, however, identified issues with the application of market power mitigation to resources whose owners fail the TPS test that can result in the exercise of local market power. These issues need to be addressed. There are issues related to the definition of gas costs includable in energy offers that need to be addressed. There are currently no market power mitigation rules in place that limit the ability to exercise market power when aggregate market conditions are tight. If market-based offer caps are raised, or if generators are allowed to modify offers hourly, market design must reflect appropriate incentives for competitive behavior and aggregate market power mitigation rules need to be developed.

Overview

Market Structure

- **Supply.** Supply includes physical generation and imports and virtual transactions. Average offered real-time generation increased by 458 MW, 0.29 percent, in the first six months of 2016 from 156,679 MW in the first six months 2015 to 157,137 MW in the first six months 2016. In the first six months of 2016, 4,634.9 MW of new capacity were added and 706 MW were retired.

  PJM average real-time generation in the first six months of 2016 decreased by 3,762 MW, or 4.2 percent, from the first six months of 2015, from 90,097 MW to 86,335 MW.

  PJM average day-ahead supply in the first six months of 2016, including INCs and up to congestion transactions, increased by 10.9 percent from the first six months of 2015, from 115,148 MW to 127,748 MW, primarily as a result of an increase in UTC volumes.

- **Market Concentration.** The PJM Energy Market was moderately concentrated overall with moderate concentration in the baseload and intermediate segments, but high concentration in the peaking segment.

- **Generation Fuel Mix.** During the first six months of 2016, coal units provided 32.2 percent, nuclear units 36.5 percent and gas units 25.7 percent of total generation. Compared to the first six months 2015, generation from coal units decreased 16.3 percent, generation from gas units increased 21.7 percent and generation from nuclear units increased 2.0 percent.

- **Marginal Resources.** In the PJM Real-Time Energy Market, in the first six months of 2016, coal units were 44.39 percent of marginal resources and natural gas units were 43.38 percent of marginal resources. In the first six months of 2015, coal units were 32.85 percent and natural gas units were 56.12 percent of the marginal resources.

  In the PJM Day-Ahead Energy Market, in the first six months of 2016, up to congestion transactions were 83.3 percent of marginal resources, INCs were 3.8 percent of marginal resources, DECs were 7.3 percent of marginal resources, and generation resources were 5.5 percent of marginal resources. In the first six months of 2015, up to congestion transactions were 74.1 percent of marginal resources, INCs were 5.4 percent of marginal resources, DECs were 9.1 percent of marginal resources, and generation resources were 11.0 percent of marginal resources.

- **Demand.** Demand includes physical load and exports and virtual transactions. The PJM metered system peak load during the first six months of 2016 was 134,958 MW in the HE 1700 on June 20, 2016, which was 8,157 MW, 5.7 percent, lower than the PJM peak load for the first

2 PJM. OATT Attachment M (PJM Market Monitoring Plan).
3 The market performance test means that offer capping is not applied if the offer does not exceed the competitive level and therefore market power would not affect market performance.

six months of 2015, which was 143,086 MW in the HE 0800 on February 20, 2015.

PJM average real-time load in the first six months of 2016 decreased by 5.3 percent from the first six months of 2015, from 90,586 MW to 85,800 MW. PJM average day-ahead demand in the first six months of 2016, including DECs and up to congestion transactions, decreased by 5.3 percent from the first six months of 2015, from 94,782 MW to 89,746 MW.

- **Supply and Demand: Load and Spot Market.** Companies that serve load in PJM can do so using a combination of self-supply, bilateral market purchases and spot market purchases. For the first six months of 2016, 8.4 percent of real-time load was supplied by bilateral contracts, 26.8 percent by spot market purchases and 64.8 percent by self-supply. Compared with the first six months of 2015, reliance on bilateral contracts increased by 1.5 percentage points, reliance on spot market purchases decreased by 6.1 percentage points and reliance on self-supply increased by 4.6 percentage points.
- **Supply and Demand: Scarcity.** There were no shortage pricing events in the first six months of 2016.

Market Behavior

- **Offer Capping for Local Market Power.** PJM offer caps units when the local market structure is noncompetitive. Offer capping is an effective means of addressing local market power. Offer capping levels have historically been low in PJM. In the Day-Ahead Energy Market, for units committed to provide energy for local constraint relief, offer-capped unit hours decreased from 0.2 percent in the first six months of 2015 to 0.1 percent in the first six months of 2016. In the Real-Time Energy Market, for units committed to provide energy for local constraint relief, offer-capped unit hours decreased from 0.5 percent in the first six months of 2015 to 0.3 percent in the first six months of 2016.

  In the first six months of 2016, 11 control zones experienced congestion resulting from one or more constraints binding for 50 or more hours. The analysis of the application of the TPS test to local markets demonstrates that it is working successfully to identify pivotal owners when the market structure is noncompetitive and to ensure that owners are not subject to offer capping when the market structure is competitive. There are, however, identified issues with the application of market power mitigation to resources whose owners fail the TPS test that can result in the exercise of local market power. These issues need to be addressed.
- **Offer Capping for Reliability.** PJM also offer caps units that are committed for reliability reasons, specifically for black start service and reactive service. In the Day-Ahead Energy Market, for units committed for reliability reasons, offer-capped unit hours decreased from 0.5 percent in the first six months of 2015 to 0.03 percent in the first six months of 2016. In the Real-Time Energy Market, for units committed for reliability reasons, offer-capped unit hours decreased from 0.6 percent in the first six months of 2015 to 0.03 percent in the first six months of 2016.
- **Markup Index.** The markup index is a summary measure of participant offer behavior for individual marginal units. In the PJM Real-Time Energy Market, when using unadjusted cost offers, in the first six month of 2016, 89.4 percent of marginal units had average dollar markups less than zero and had an average markup index less than zero. Using adjusted cost offers, in the first six months of 2016, 20.0 percent of marginal units had average dollar markups less than zero. Some marginal units did have substantial markups. Among the units that were marginal in the first six months of 2016, none had offer prices above $400 per MWh.

  In the PJM day-ahead energy market, when using unadjusted cost offers, in the first six months of 2016, 62.9 percent of marginal generating units had an average markup index less than or equal to zero. Using adjusted cost offers, in the first six months of 2016, no marginal units had an average markup index less than or equal to zero.
- **Frequently Mitigated Units (FMU) and Associated Units (AU).** A new FMU rule became effective November 1, 2014, limiting the availability of FMU adders to units with net revenues less than unit going forward costs. The number of units that were eligible for an FMU or AU adder declined

from an average of 70 units during the first 11 months of 2014, to zero since December 2014.

- **Virtual Offers and Bids.** Any market participant in the PJM Day-Ahead Energy Market can use increment offers, decrement bids, up to congestion transactions, import transactions and export transactions as financial instruments that do not require physical generation or load. The reduction in up to congestion transactions (UTC) that had followed a FERC order setting September 8, 2014, as the effective date for any uplift charges subsequently assigned to UTCs, was reversed. There was an increase in up to congestion volume as a result of the expiration of the fifteen month refund period for the proceeding related to uplift charges for UTC transactions. In the first six months of 2016, the average hourly up to congestion submitted MW increased by 101.9 percent from 68,947 MW in the first six months of 2015 to 139,199 MW in the first six months of 2016, and cleared MW increased by 98.7 percent from 17,421 MW in the first six months of 2015 to 34,607 MW in the first six months of 2016.

- **Generator Offers.** Generator offers are categorized as dispatchable and self scheduled. Units which are available for economic dispatch are dispatchable. Units which are self scheduled to generate fixed output are categorized as self scheduled. Units which are self scheduled at their economic minimum and are available for economic dispatch up to their economic maximum are categorized as self scheduled and dispatchable. Of all generator offers in the first six months of 2016, 52.5 percent were offered as available for economic dispatch, 22.0 percent were offered as self scheduled, and 17.9 percent were offered as self scheduled and dispatchable.

Market Performance

- **Prices.** PJM LMPs are a direct measure of market performance. Price level is a good, general indicator of market performance, although the number of factors influencing the overall level of prices means it must be analyzed carefully. Among other things, overall average prices reflect changes in supply and demand, generation fuel mix, the cost of fuel, emission related expenses, markup and local price differences caused by congestion. PJM also may administratively set prices with the creation of a closed loop interface related to demand side resources or reactive power or the application of price setting logic.

  PJM real-time energy market prices decreased in the first six months of 2016 compared to the first six months of 2015. The load-weighted average real-time LMP was 36.0 percent lower in the first six months of 2016 than in the first six months of 2015, $27.09 per MWh versus $42.30 per MWh.

  PJM day-ahead energy market prices decreased in the first six months of 2016 compared to the first six months of 2015. The load-weighted average day-ahead LMP was 36.8 percent lower in the first six months of 2016 than in the first six months of 2015, $27.33 per MWh versus $43.26 per MWh.

- **Components of LMP.** In the PJM Real-Time Energy Market, for the first six months of 2016, 53.0 percent of the load-weighted LMP was the result of coal costs, 21.5 percent was the result of gas costs and 2.17 percent was the result of the cost of emission allowances.

  In the PJM day-ahead energy market for the first six months of 2016, 29.8 percent of the load-weighted LMP was the result of the cost of coal, 22.6 percent was the result of DECs, 13.6 percent was the result of the cost of gas, 14.5 percent was the result of INCs, and 4.4 percent was the result of up to congestion transactions.

- **Markup.** The markup conduct of individual owners and units has an identifiable impact on market prices. Markup is a key indicator of the competitiveness of the energy market.

  In the PJM Real-Time Energy Market in the first six months of 2016, the adjusted markup component of LMP was $0.97 per MWh or 3.6 percent of the PJM real-time, load-weighted average LMP. April had the highest adjusted peak markup component, $3.50 per MWh, or 10.58 percent of the real-time load-weighted average LMP. Using the unadjusted cost offers, the highest markup in the first six months of 2016 was $258.16 per MWh. There were 14 hours in the first six months of 2016 where the positive markup contribution to the PJM system wide, load-weighted, average LMP exceeded $54.54 per MWh.

In the PJM Day-Ahead Energy Market, marginal INCs, DECs and UTCs have zero markups. In the first six months of 2016, the adjusted markup component of LMP resulting from generation resources was $1.29 per MWh or 4.7 percent of the PJM day-ahead load-weighted average LMP. January had the highest adjusted markup component, $2.26 per MWh or 7.3 percent of the day-ahead load-weighted average LMP.

Participant behavior was evaluated as competitive because the analysis of markup shows that marginal units generally make offers at, or close to, their marginal costs in both the Day-Ahead and Real-Time Energy Markets, although the behavior of some participants during the high demand periods in the first three months is consistent with economic withholding.

- **Price Convergence.** Hourly and daily price differences between the Day-Ahead and Real-Time Energy Markets fluctuate continuously and substantially from positive to negative. The difference between the average day-ahead and real-time prices was -$1.17 per MWh in the first six months of 2015 and -$0.39 per MWh in the first six months of 2016. The difference between average day-ahead and real-time prices, by itself, is not a measure of the competitiveness or effectiveness of the Day-Ahead Energy Market.

Scarcity

- There were no shortage pricing events in the first six months of 2016.

Recommendations

- The MMU recommends that PJM retain the $1,000 per MWh offer cap in the PJM Energy Market except when cost-based offers exceed $1,000 per MWh, and retain other existing rules that limit incentives to exercise market power. (Priority: High. First reported 1999. Status: Partially adopted, 1999.)
- The MMU recommends that the rules governing the application of the TPS test be clarified and documented. (Priority: High. First reported 2010. Status: Not adopted.)
- The MMU recommends, in order to ensure effective market power mitigation when the TPS test is failed, that markup be constant across price and cost offers, that there be at least one cost-based offer using the same fuel as the available price-based offer. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that in order to ensure effective market power mitigation when the TPS test is failed, the operating parameters in the cost-based offer and the price-based parameter limited schedule (PLS) offer be at least as flexible as the operating parameters in the available non-PLS price-based offer, and that the price-MW pairs in the price based PLS offer be exactly equal to the price-based non-PLS offer. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM require all generating units to identify the fuel type associated with each of their offered schedules. (Priority: Low. First reported 2014. Status: Adopted in full, Q4, 2014.)
- The MMU recommends that under the capacity performance construct, PJM recognize the difference between operational parameters that indicate to PJM dispatchers what a unit is capable of during the operating day and the parameters that are used for capacity performance assessment as well as uplift payments. The parameters which determine nonperformance charges and the amount of uplift payments to those generators should reflect the flexibility goals of the capacity performance construct. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that capacity performance resources and base capacity resources (during the June through September period) be held to the OEM operating parameters of the capacity market CONE reference resource for performance assessment and energy uplift payments. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM remove nonspecific fuel types such as “other” or “co-fire other” from the list of fuel types available for market

participants to identify the fuel type associated with their price and cost schedules. (Priority: Medium. First reported 2015. Status: Not adopted.)

- The MMU recommends that a unit which is not capable of supplying energy consistent with its day-ahead offer should reflect an appropriate outage rather than indicating its availability to supply energy on an emergency basis. (Priority: Low. First reported 2009. Status: Not Adopted.)
- The MMU recommends that PJM explain how LMPs are calculated when demand response is marginal. The LMPs in excess of $1,800 per MWh on January 7, 2014, were potentially a result of the way in which PJM modeled zonal (not nodal) demand response as a marginal resource. (Priority: Low. First reported 2014. Status: Not Adopted.)
- The MMU recommends that PJM explicitly state its policy on the use of transmission penalty factors including the level of the penalty factors, the triggers for the use of the penalty factors, the appropriate line ratings to trigger the use of penalty factors, and when the transmission penalty factors will be used to set the shadow price. (Priority: Medium. First reported 2015.Status: Not adopted.)
- The MMU recommends that PJM explicitly state its policy on the use of constraint relaxation logic and price setting logic. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that PJM routinely review all transmission facility ratings and any changes to those ratings to ensure that the normal, emergency and load dump ratings used in modeling the transmission system are accurate and reflect standard ratings practice. (Priority: Low. First reported 2013. Status: Partially adopted.)
- The MMU recommends that the definition of maximum emergency status in the tariff apply at all times rather than just during maximum emergency events.[4] (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM update the outage impact studies, the reliability analyses used in RPM for capacity deliverability and the reliability analyses used in RTEP for transmission upgrades to be consistent with the more conservative emergency operations (post contingency load dump limit exceedance analysis) in the energy market that were implemented in June 2013. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that the roles of PJM and the transmission owners in the decision making process to control for local contingencies be clarified, that PJM's role be strengthened and that the process be made transparent. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM include in the appropriate manual an explanation of the initial creation of hubs, the process for modifying hub definitions and a description of how hub definitions have changed.[5] There is currently no PJM documentation in the tariff or manuals explaining how hubs are created and how their definitions are changed.[6] (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that during hours when a generation bus shows a net withdrawal, the energy withdrawal be treated as load, not negative generation, for purposes of calculating load and load-weighted LMP. The MMU recommends that during hours when a load bus shows a net injection, the energy injection be treated as generation, not negative load, for purposes of calculating generation and load-weighted LMP. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM identify and collect data on available behind the meter generation resources, including nodal location information and relevant operating parameters. (Priority: Low. First reported 2013. Status: Partially adopted.)
- The MMU recommends that PJM continue to enhance its posting of market data to promote market efficiency. (Priority: Medium. First reported 2005. Status: Partially Adopted.)
- The MMU recommends the elimination of FMU and AU adders. FMU and AU adders no longer serve the purpose for which they were created and interfere with the efficient operation of PJM markets. (Priority: Medium. First reported 2012. Status: Adopted partially, Q4, 2014.)

4 PJM. OATT Section: 6A.1.3 Maximum Emergency, (February 25, 2014), p. 1740, 1795.

5 According to minutes from the first meeting of the Energy Market Committee (EMC) on January 28, 1998, the EMC unanimously agreed to be responsible for approving additions, deletions and changes to the hub definitions to be published and modeled by PJM. Since the EMC has become the Market Implementation Committee (MIC), the MIC now appears to be responsible for such changes.

6 The general definition of a hub can be found in PJM. "Manual 35: Definitions and Acronyms," Revision 23 (April 11, 2014).

Conclusion

The MMU analyzed key elements of PJM energy market structure, participant conduct and market performance in the first six months of 2016, including aggregate supply and demand, concentration ratios, three pivotal supplier test results, offer capping, participation in demand response programs, loads and prices.

Average PJM real-time generation decreased by 3,762 MW, 4.2 percent, and peak load decreased by 8,157 MW, 5.7 percent, in the first six months of 2016 compared to the first six months of 2015. Market concentration levels remained moderate although there is high concentration in the peaking segment of the supply curve which adds to concerns about market power when market conditions are tight. The relationship between supply and demand, regardless of the specific market, balanced by market concentration and the extent of pivotal suppliers, is referred to as the supply-demand fundamentals or economic fundamentals. While the market structure does not guarantee competitive outcomes, overall the market structure of the PJM aggregate energy market remains reasonably competitive for most hours although aggregate market power does exist during high demand hours. Low average aggregate concentration does not mean that market power cannot be exercised. It is possible that market power can be exercised at times when individual suppliers or small groups of suppliers are pivotal even when the average HHI is unconcentrated.

Prices are a key outcome of markets. Prices vary across hours, days and years for multiple reasons. Price is an indicator of the level of competition in a market although individual prices are not always easy to interpret. In a competitive market, prices are directly related to the marginal cost of the most expensive unit required to serve load in each hour. The pattern of prices within days and across months and years illustrates how prices are directly related to supply and demand conditions and thus also illustrates the potential significance of the impact of the price elasticity of demand on prices. Energy market results in the first six months of 2016 generally reflected supply-demand fundamentals, although the behavior of some participants during high demand periods is consistent with economic withholding. Economic withholding is the ability to increase markups substantially in tight market conditions. There are additional issues in the energy market including the uncertainties about the pricing and availability of natural gas, the way that generation owners incorporate natural gas costs in offers, and the lack of adequate incentives for unit owners to take all necessary actions to acquire fuel and operate rather than take an outage.

The three pivotal supplier test is applied by PJM on an ongoing basis for local energy markets in order to determine whether offer capping is required for transmission constraints.[7] This is a flexible, targeted real-time measure of market structure which replaced the offer capping of all units required to relieve a constraint. A generation owner or group of generation owners is pivotal for a local market if the output of the owners' generation facilities is required in order to relieve a transmission constraint. When a generation owner or group of owners is pivotal, it has the ability to increase the market price above the competitive level. The three pivotal supplier test explicitly incorporates the impact of excess supply and implicitly accounts for the impact of the price elasticity of demand in the market power tests. The result of the introduction of the three pivotal supplier test was to limit offer capping to times when the local market structure was noncompetitive and specific owners had structural market power. The analysis of the application of the three pivotal supplier test demonstrates that it is working for most hours to exempt owners when the local market structure is competitive and to require offer capping of owners when the local market structure is noncompetitive.

However, there are some issues with the application of mitigation in the Day-Ahead Energy Market and the Real-Time Energy Market when market sellers fail the TPS test. There is no tariff or manual language that defines in detail the application of the TPS test and offer capping in the Day-Ahead Energy Market and the Real-Time Energy Market. In both the Day-Ahead and Real-Time Energy Markets, generators have the ability to avoid mitigation by using varying markups in their price-based offers, offering different operating parameters in their price-based and cost-based offers, and using different

7 The MMU reviews PJM's application of the TPS test and brings issues to the attention of PJM.

fuels in their price-based and cost-based offers. These issues can be resolved by simple rule changes requiring that markup be constant across price and cost offers, that there be at least one cost-based offer using the same fuel as the available price-based offer, that the price-MW pairs in the price based PLS offer be exactly equal to the price-based non-PLS offer, and requiring cost-based and price-based PLS offers to be at least as flexible as price-based non-PLS offers.

PJM also offer caps units that are committed for reliability reasons in addition to units committed to provide constraint relief. Specifically, units that are committed to provide reactive support and black start service are offer capped in the energy market. These units are committed manually in both the Day-Ahead and Real-Time Energy Markets.

With or without a capacity market, energy market design must permit scarcity pricing when such pricing is consistent with market conditions and constrained by reasonable rules to ensure that market power is not exercised. Scarcity pricing can serve two functions in wholesale power markets: revenue adequacy and price signals. Scarcity pricing for revenue adequacy is not required in PJM. Scarcity pricing for price signals that reflect market conditions during periods of scarcity is required in PJM. Scarcity pricing is also part of an appropriate incentive structure facing both load and generation owners in a working wholesale electric power market design. Scarcity pricing must be designed to ensure that market prices reflect actual market conditions, that scarcity pricing occurs with transparent triggers based on measured reserve levels and transparent prices and that there are strong incentives for competitive behavior and strong disincentives to exercise market power. Such administrative scarcity pricing is a key link between energy and capacity markets. The PJM Capacity Market is explicitly designed to provide revenue adequacy and the resultant reliability. Nonetheless, with a market design that includes a direct and explicit scarcity pricing net revenue true up mechanism, scarcity pricing can be a mechanism to appropriately increase reliance on the energy market as a source of revenues and incentives in a competitive market without reliance on the exercise of market power. PJM implemented scarcity pricing rules in 2012. There are significant issues with the scarcity pricing net revenue true up mechanism in the PJM scarcity pricing design, which will create issues when scarcity pricing occurs. There are also significant issues with PJM's scarcity pricing rules, including the absence of a clear trigger based on measured reserve levels (the current triggers are based on estimated reserves) and the lack of adequate locational scarcity pricing options.

The overall energy market results support the conclusion that energy prices in PJM are set, generally, by marginal units operating at, or close to, their marginal costs, although this was not always the case during the high demand hours in the first six months of 2014, 2015 or 2016. This is evidence of generally competitive behavior and competitive market outcomes, although the behavior of some participants during the high demand periods is consistent with economic withholding. Given the structure of the energy market which can permit the exercise of aggregate market power at times of high demand, the tighter market conditions and the change in some participants' behavior are sources of concern in the energy market and provide a reason to use cost as the sole basis for hourly changes in offers or offers greater than $1,000 per MWh. The MMU concludes that the PJM energy market results were competitive in the first six months of 2016.

Market Structure

Market Concentration

Analysis of supply curve segments of the PJM energy market in the first six months of 2016 indicates moderate concentration in the base load and intermediate segments, but high concentration in the peaking segment.[8] High concentration levels, particularly in the peaking segment, increase the probability that a generation owner will be pivotal in the aggregate market during high demand periods.

When transmission constraints exist, local markets are created with ownership that is typically significantly more concentrated than the overall energy market. PJM offer capping rules that limit the exercise of local market power

8 A unit is classified as base load if it runs for more than 50 percent of hours in the six month period, as intermediate if it runs for less than 50 percent but greater than 10 percent of hours in the six month period, and as peak if it runs for less than 10 percent of hours in the six month period.

were generally effective in preventing the exercise of market power in the first six months of 2016, although there are issues with the application of market power mitigation for resources whose owners fail the TPS test.

The concentration ratio used here is the Herfindahl-Hirschman Index (HHI), calculated by summing the squares of the market shares of all firms in a market. Hourly PJM energy market HHIs were calculated based on the real-time energy output of generators, adjusted for hourly net imports by owner (Table 3-2).

The HHI may not accurately capture market power issues in situations where, for example, there is moderate concentration in all on line resources but there is a high level of concentration in resources needed to meet increases in load. The HHIs for supply curve segments is an indication of such issues. An aggregate pivotal supplier test is required to accurately measure the ability of incremental resources to exercise market power when load is high, for example.

Hourly HHIs were also calculated for baseload, intermediate and peaking segments of generation supply. Hourly energy market HHIs by supply curve segment were calculated based on hourly energy market shares, unadjusted for imports.

The "Merger Policy Statement" of the FERC states that a market can be broadly characterized as:

- **Unconcentrated.** Market HHI below 1000, equivalent to 10 firms with equal market shares;
- **Moderately Concentrated.** Market HHI between 1000 and 1800; and
- **Highly Concentrated.** Market HHI greater than 1800, equivalent to between five and six firms with equal market shares.[9]

9 77 FERC ¶ 61,263, pp. 64-70 (1996), "*Inquiry Concerning the Commission's Merger Policy under the Federal Power Act: Policy Statement.*"

PJM HHI Results

Calculations for hourly HHI indicate that by the FERC standards, the PJM Energy Market during the first six months of 2016 was moderately concentrated (Table 3-2).

Table 3-2 PJM hourly energy market HHI: January through June, 2015 and 2016[10]

	Hourly Market HHI (Jan - Jun, 2015)	Hourly Market HHI (Jan - Jun, 2016)
Average	1117	1073
Minimum	916	837
Maximum	1468	1356
Highest market share (One hour)	30%	28%
Average of the highest hourly market share	21%	20%
# Hours	4,343	4,367
# Hours HHI > 1800	0	0
% Hours HHI > 1800	0%	0%

Table 3-3 includes HHI values by supply curve segment, including base, intermediate and peaking plants for the first six months of 2015 and 2016. The PJM Energy Market was moderately concentrated overall with moderate concentration in the baseload and intermediate segments, but high concentration in the peaking segments.

Table 3-3 PJM hourly energy market HHI (By supply segment): January through June, 2015 and 2016

	Jan - Jun, 2015			Jan - Jun, 2016		
	Minimum	Average	Maximum	Minimum	Average	Maximum
Base	1021	1148	1489	984	1157	1443
Intermediate	693	2016	8147	630	1580	6328
Peak	802	6080	10000	687	5821	10000

Figure 3-1 shows the number of units in the baseload, intermediate and peaking segments by fuel source in the first six months of 2016.

10 This analysis includes all hours in the first six months of 2015 and 2016, regardless of congestion.

Figure 3-1 Fuel source distribution in unit segments: January through June, 2016[11]

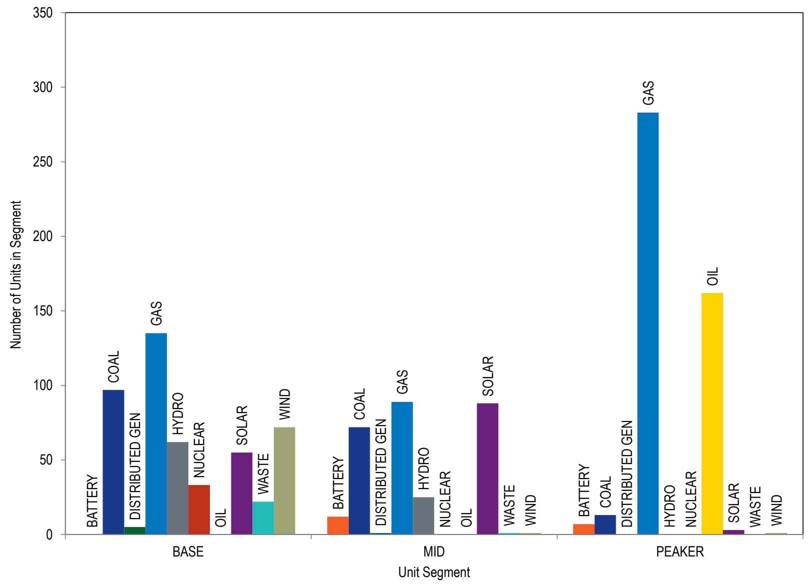
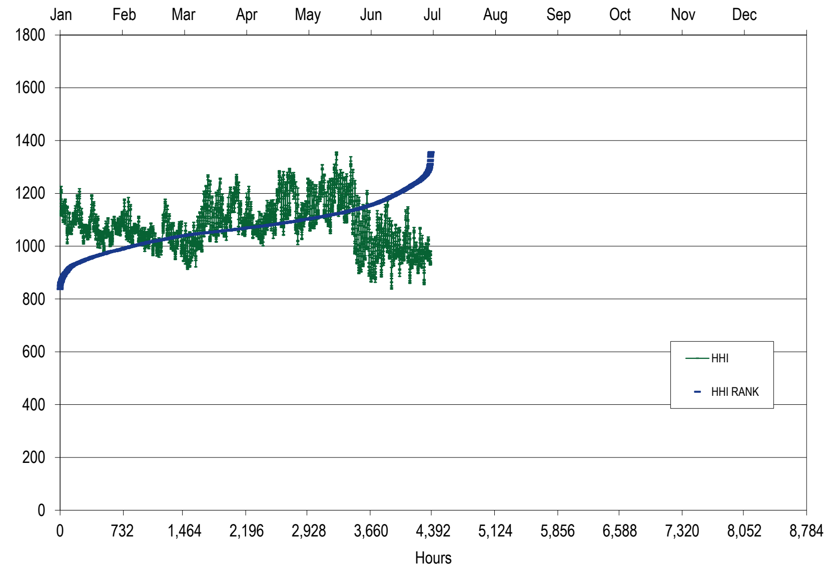


Figure 3-2 presents the hourly HHI values in chronological order and an HHI duration curve for the first six months of 2016.

Figure 3-2 PJM hourly energy market HHI: January through June, 2016



Ownership of Marginal Resources

Table 3-4 shows the contribution to real-time, load-weighted LMP by individual marginal resource owner.[12] The contribution of each marginal resource to price at each load bus is calculated for each five-minute interval of 2016, and summed by the parent company that offers the marginal resource into the Real-Time Energy Market. In the first six months of 2016, the offers of one company resulted in 24.6 percent of the real-time, load-weighted PJM system LMP and that the offers of the top four companies resulted in 61.2 percent of the real-time, load-weighted, average PJM system LMP. During the first six months of 2015, the offers of one company resulted in 17.9 percent

11 The units classified as Distributed Gen are buses within Electric Distribution Companies (EDCs) that are modeled as generation buses to accurately reflect net energy injections from distribution level load buses. The modeling change was the outcome of the Net Energy Metering Task Force stakeholder group in July, 2012. See PJM. "Net Energy Metering Senior Task Force (NEMSTF) Action on Proposed Manual 28 Revisions," (July 26, 2012) <http://www.pjm.com/~/media/committees-groups/committees/mrc/20120726/20120726-item-04-nemstf-report-and-proposed-manual-revisions.ashx>.

12 See the *MMU Technical Reference for PJM Markets*, at "Calculation and Use of Generator Sensitivity/Unit Participation Factors."

of the real time, load-weighted PJM system LMP and offers of the top four companies resulted in 55.0 percent of the real-time, load-weighted, average PJM system LMP. In the first six months of 2016, the offers of one company resulted in 25.7 percent of the peak hour real-time, load weighted PJM system LMP. In the first six months of 2015, the offers of one company resulted in 15.3 percent of the peak hour, real-time, load weighted PJM system LMP.

Table 3-4 Marginal unit contribution to PJM real-time, load-weighted LMP (By parent company): January through June, 2015 and 2016

2015 (Jan-Jun)				2016 (Jan-Jun)			
All Hours		Peak Hours		All Hours		Peak Hours	
Company	Percent of Price	Company	Percent of Price	Company	Percent of Price	Company	Percent of Price
1	17.9%	1	15.3%	1	24.6%	1	25.7%
2	15.6%	2	14.2%	2	15.8%	2	17.6%
3	11.5%	3	10.5%	3	11.3%	3	9.8%
4	10.0%	4	10.3%	4	9.6%	4	9.2%
5	8.4%	5	9.8%	5	8.0%	5	6.6%
6	8.2%	6	9.6%	6	6.7%	6	6.2%
7	5.3%	7	6.1%	7	2.4%	7	2.5%
8	4.6%	8	4.2%	8	2.3%	8	2.4%
9	2.8%	9	3.0%	9	2.3%	9	2.4%
Other (54 companies)	15.6%	Other (48 companies)	17.1%	Other (66 companies)	17.2%	Other (58 companies)	17.8%

Table 3-5 Marginal resource contribution to PJM day-ahead, load-weighted LMP (By parent company): January through June, 2015 and 2016

2015 (Jan - Jun)				2016 (Jan - Jun)			
All Hours		Peak Hours		All Hours		Peak Hours	
Company	Percent of Price	Company	Percent of Price	Company	Percent of Price	Company	Percent of Price
1	12.0%	1	11.5%	1	16.1%	1	14.8%
2	11.8%	2	10.1%	2	8.6%	2	9.3%
3	8.7%	3	8.6%	3	8.4%	3	9.0%
4	6.5%	4	7.4%	4	7.6%	4	7.9%
5	5.9%	5	7.0%	5	7.1%	5	7.2%
6	5.6%	6	5.7%	6	4.6%	6	4.9%
7	5.1%	7	4.6%	7	4.6%	7	3.5%
8	4.2%	8	4.4%	8	4.0%	8	2.9%
9	3.8%	9	4.0%	9	3.6%	9	2.7%
Other (132 companies)	36.3%	Other (128 companies)	36.9%	Other (149 companies)	35.4%	Other (142 companies)	37.9%

Table 3-5 shows the contribution to day-ahead, load-weighted LMP by individual marginal resource owners.[13] The contribution of each marginal resource to price at each load bus is calculated hourly, and summed by the parent company that offers the marginal resource into the Day-Ahead Energy Market. The results show that in the first six months of 2016, the offers of one company contributed 16.1 percent of the day-ahead, load-weighted PJM system LMP and that the offers of the top four companies contributed 40.7 percent of the day-ahead, load-weighted, average PJM system LMP. In the first six months of 2015, the offers of one company contributed 12.0 percent of the day-ahead, load-weighted PJM system LMP and offers of the top four companies contributed 39.0 percent of the day-ahead, load-weighted, average PJM system LMP.

Type of Marginal Resources

LMPs result from the operation of a market based on security-constrained, least-cost dispatch in which marginal resources determine system LMPs, based on their offers. Marginal resource designation is not limited to physical resources in the Day-Ahead Energy Market. INC offers, DEC bids and up to congestion transactions are dispatchable injections and withdrawals in the Day-Ahead Energy Market that can set price via their offers and bids.

Table 3-6 shows the type of fuel used by marginal resources in the Real-Time Energy Market. There can be more than one marginal resource in any given interval as a result of transmission constraints. In the first six months of 2016, coal units were 44.39 percent and natural gas units were 43.38 percent of marginal resources. In the first six months of 2015, coal units were 32.85 percent and natural gas units were 56.12 percent

13 See the *MMU Technical Reference for PJM Markets*, at "Calculation and Use of Generator Sensitivity/Unit Participation Factors."

of the total marginal resources. In the first six months of 2016, 85.10 percent of the wind marginal units had negative offer prices, 11.92 percent had zero offer prices and 2.98 percent had positive offer prices.

The results reflect the dynamics of an LMP market. When there is a single constraint, there are two marginal units. For example, a significant west to east constraint could be binding with a gas unit marginal in the east and a coal unit marginal in the west. As a result, although the dispatch of natural gas units has increased and gas units set price for more hours as marginal resources in the Real-Time Energy Market, this does not necessarily reduce the proportion of hours in which coal units are marginal.[14]

Table 3-6 Type of fuel used (By real-time marginal units): January through June, 2012 through 2016

	Year (Jan - Jun)				
Type/Fuel	2012	2013	2014	2015	2016
Gas	30.04%	33.26%	42.02%	32.85%	44.39%
Coal	59.41%	57.63%	48.59%	56.12%	43.38%
Oil	4.07%	3.08%	3.64%	7.37%	7.73%
Wind	6.03%	5.86%	5.10%	3.11%	3.37%
Uranium	0.00%	0.02%	0.09%	0.05%	0.97%
Other	0.31%	0.15%	0.42%	0.43%	0.14%
Municipal Waste	0.13%	0.01%	0.05%	0.06%	0.02%
Emergency DR	0.00%	0.00%	0.08%	0.00%	0.00%

Figure 3-3 shows the type of fuel used by marginal resources in the Real-Time Energy Market since 2004. The role of coal as a marginal resource has declined while the role of gas as a marginal resource has increased.

Figure 3-3 Type of fuel used (By real-time marginal units): January through June, 2004 through 2016

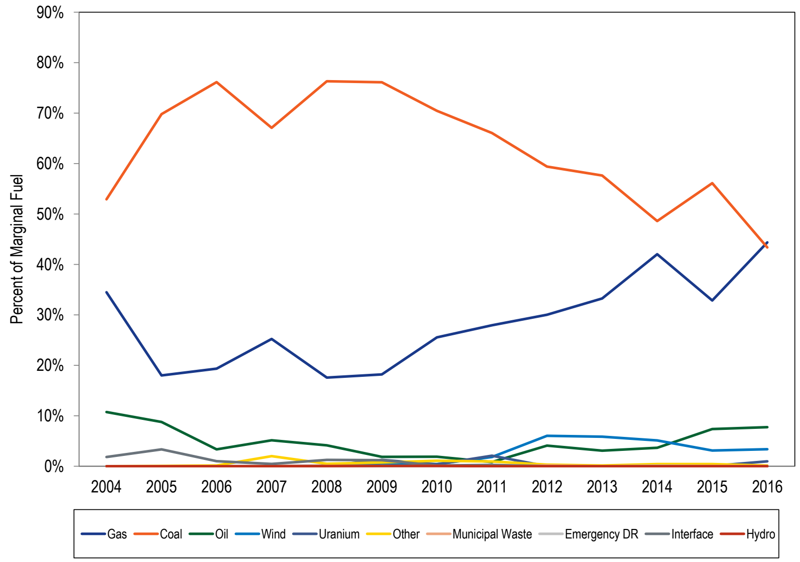


Table 3-7 shows the type and fuel type where relevant, of marginal resources in the Day-Ahead Energy Market. In the first six months of 2016, up to congestion transactions were 83.34 percent of marginal resources. Up to congestion transactions were 74.08 percent of marginal resources in the first six months of 2015.

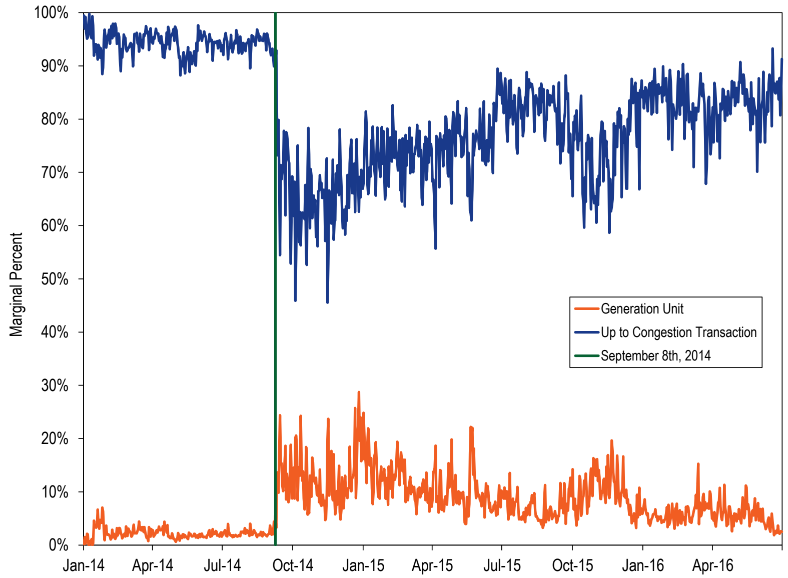
14 Prior to April 1, 2015, for the generation units that are capable of using multiple fuel types, PJM did not require the participants to disclose the fuel type associated with their offer schedule. For these units, the cleared offer schedules on a given day were compared to the cost associated with each fuel to determine the fuel type most likely to have been the basis for the cleared schedule.

Table 3-7 Day-ahead marginal resources by type/fuel: January through June, 2011 through 2016

	(Jan - Jun)					
Type/Fuel	2011	2012	2013	2014	2015	2016
Up to Congestion Transaction	67.39%	86.01%	95.88%	94.25%	74.08%	83.34%
DEC	15.03%	5.26%	1.22%	2.07%	9.11%	7.30%
INC	8.78%	4.97%	0.98%	1.38%	5.35%	3.80%
Gas	2.03%	1.06%	0.54%	0.94%	3.27%	2.42%
Coal	6.06%	2.53%	1.26%	1.20%	7.14%	2.38%
Oil	0.00%	0.00%	0.00%	0.02%	0.42%	0.57%
Dispatchable Transaction	0.31%	0.07%	0.07%	0.10%	0.38%	0.06%
Wind	0.09%	0.04%	0.04%	0.03%	0.18%	0.05%
Uranium	0.00%	0.00%	0.00%	0.00%	0.00%	0.04%
Nuclear	0.00%	0.00%	0.00%	0.00%	0.00%	0.02%
Municipal Waste	0.02%	0.00%	0.00%	0.00%	0.01%	0.02%
Total	100.00%	100.00%	99.99%	100.00%	100.00%	100.00%

Figure 3-4 shows, for the Day-Ahead Market from January 1, 2014, through March 31, 2015, the daily proportion of marginal resources that were up to congestion transaction and/or generation units. The percentage of marginal up to congestion transactions decreased significantly beginning on September 8, 2014, as a result of the FERC's UTC uplift refund notice which became effective on that date.[15] The percentage of marginal up to congestion transaction decreased and that of generation units increased. That trend has begun to reverse as a result of the expiration of the fifteen month refund period for the proceeding related to uplift charges for UTC transactions.

Figure 3-4 Day-ahead marginal up to congestion transaction and generation units: 2014 through June of 2016



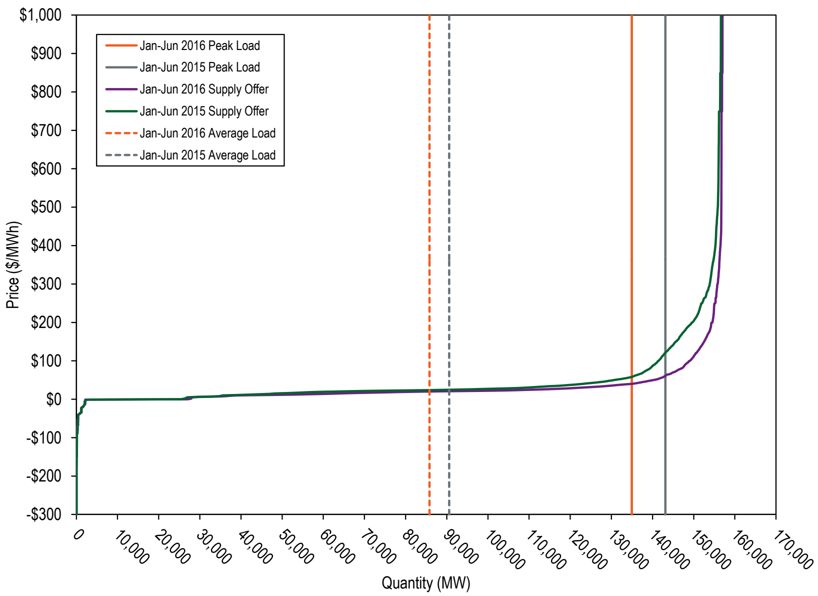
Supply

Supply includes physical generation and imports and virtual transactions.

Figure 3-5 shows the average PJM aggregate real-time generation supply curves by offer price, peak load and average load for the first six months of 2015 and 2016. Total average PJM aggregate real-time generation supply increased by 458 MW, or 0.29 percent, in the first six months of 2016 from 156,679 MW in the first six months of 2015 to 157,137 MW in the first six months of 2016.

15 See 18 CFR § 385.213 (2014).

Figure 3-5 Average PJM aggregate real-time generation supply curves by offer price: January through June, 2015 and 2016



Energy Production by Fuel Source

Table 3-8 shows PJM generation by fuel source in GWh for the first six months of 2015 and the first six months of 2016. In the first six months of 2016, generation from coal units decreased 31.7 percent and generation from natural gas units increased 19.4 percent compared to the first six months of 2015.[16]

Table 3-8 PJM generation (By fuel source (GWh)): January through June, 2015 and 2016[17 18]

Jan-Jun		2015 GWh	2015 Percent	2016 GWh	2016 Percent	Change in Output
Coal		147,350.6	37%	122,736.8	32%	(16.7%)
	Standard Coal	29,947.0	8%	2,876.0	1%	(90.4%)
	Waste Coal	708.7	0%	1,441.2	0%	103.4%
	Bituminous	103,534.6	26%	107,212.5	28%	3.6%
	Sub Bituminous	13,160.4	3%	11,207.1	3%	(14.8%)
Nuclear		137,027.2	34%	138,971.3	36%	1.4%
Gas		80,979.5	20%	97,975.7	26%	21.0%
	Natural Gas	79,792.2	20%	97,072.7	25%	21.7%
	Landfill Gas	991.8	0%	903.0	0%	(9.0%)
	Other Gas	195.4	0%	0.1	0%	(100.0%)
Hydroelectric		6,614.0	2%	7,623.1	2%	15.3%
	Pumped Storage	2,044.4	1%	2,119.7	1%	3.7%
	Run of River	3,416.5	1%	4,775.2	1%	39.8%
	Other Hydro	1,153.1	0%	728.2	0%	(36.8%)
Wind		8,790.0	2%	9,650.3	3%	9.8%
Waste		2,061.6	1%	2,056.5	1%	(0.2%)
	Solid Waste	1,991.5	1%	2,056.5	1%	3.3%
	Miscellaneous	70.1	0%	0.0	0%	(100.0%)
Oil		977.1	0%	698.0	0%	(28.6%)
	Heavy Oil	435.2	0%	168.0	0%	(61.4%)
	Light Oil	485.0	0%	200.1	0%	(58.7%)
	Diesel	47.2	0%	32.2	0%	(31.8%)
	Gasoline	0.0	0%	0.0	0%	NA
	Kerosene	9.8	0%	66.9	0%	582.9%
	Jet Oil	0.0	0%	0.0	0%	NA
	Other Oil	0.0	0%	230.9	0%	NA
Solar, Net Energy Metering		255.7	0%	455.5	0%	78.1%
Energy Storage		2.7	0%	8.0	0%	196.7%
	Battery	2.7	0%	8.0	0%	196.7%
	Compressed Air	0.0	0%	0.0	0%	NA
Biofuel		585.2	0%	747.9	0%	27.8%
Geothermal		0.0	0%	0.0	0%	NA
Other Fuel Type		13,636.1	3%	0.0	0%	(100.0%)
Total		398,279.7	100%	380,923.1	100%	(4.4%)

16 Generation data are the sum of MWh for each fuel by source at every generation bus in PJM with positive output and reflect gross generation without offset for station use of any kind.

17 All generation is total gross generation output and does not net out the MWh withdrawn at a generation bus to provide auxiliary/parasitic power or station power, power to synchronous condenser motors, or power to run pumped storage pumps.
18 Net Energy Metering is combined with Solar due to data confidentiality reasons.

Table 3-9 Monthly PJM generation (By fuel source (GWh)): 2016

	Jan	Feb	Mar	Apr	May	Jun	Total
Coal	25,321.1	21,842.9	15,320.7	17,827.5	17,154.1	25,270.6	122,736.8
Standard Coal	487.9	438.8	423.6	257.0	419.9	848.8	2,876.0
Waste Coal	360.3	306.4	203.5	196.3	164.3	210.5	1,441.2
Bituminous	22,106.2	19,373.8	13,695.1	15,464.3	15,444.0	21,129.1	107,212.5
Sub Bituminous	2,366.8	1,723.9	998.4	1,909.9	1,125.9	3,082.2	11,207.1
Nuclear	25,876.0	22,914.1	22,788.2	21,022.7	23,790.7	22,579.5	138,971.3
Gas	16,105.8	15,612.1	17,187.3	13,718.8	14,995.2	20,356.6	97,975.7
Natural Gas	15,948.5	15,464.9	17,033.7	13,568.0	14,850.6	20,207.1	97,072.7
Landfill Gas	157.3	147.2	153.5	150.8	144.6	149.5	903.0
Other Gas	0.0	0.0	0.1	0.0	0.0	0.0	0.1
Hydroelectric	1,453.6	1,400.6	1,274.0	1,067.4	1,251.6	1,176.0	7,623.1
Pumped Storage	357.0	298.6	319.8	298.1	309.8	536.4	2,119.7
Run of River	974.2	1,002.0	849.4	653.4	842.8	453.5	4,775.2
Other Hydro	122.4	100.0	104.8	115.9	98.9	186.1	728.2
Wind	2,095.6	1,925.5	1,781.6	1,588.0	1,230.6	1,029.1	9,650.3
Waste	344.8	297.0	337.5	344.3	366.7	366.0	2,056.5
Solid Waste	344.8	297.0	337.5	344.3	366.7	366.0	2,056.5
Miscellaneous	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil	199.3	139.2	33.1	23.8	104.8	198.0	698.0
Heavy Oil	91.4	45.3	1.0	0.0	0.0	30.3	168.0
Light Oil	88.0	23.2	30.7	22.7	27.7	7.8	200.1
Diesel	11.6	13.6	1.3	0.7	3.3	1.8	32.2
Gasoline	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Kerosene	8.3	57.1	0.0	0.4	0.4	0.6	66.9
Jet Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Oil	0.0	0.0	0.0	0.0	73.3	157.5	230.9
Solar, Net Energy Metering	42.3	47.2	79.5	91.7	83.5	111.3	455.5
Energy Storage	1.3	1.5	1.4	1.4	1.2	1.3	8.0
Battery	1.3	1.5	1.4	1.4	1.2	1.3	8.0
Compressed Air	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biofuel	158.2	144.4	143.2	96.3	76.6	129.2	747.9
Geothermal	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Fuel Type	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	71,598.1	64,324.4	58,946.4	55,781.8	59,054.8	71,217.6	380,923.1

Net Generation and Load

PJM sums all negative (injections) and positive (withdrawals) load at each designated load bus when calculating net load (accounting load). PJM sums all of the negative (withdrawals) and positive (injections) generation at each generation bus when calculating net generation. Netting withdrawals and injections by bus type (generation or load) affects the measurement of total load and total generation. Energy withdrawn at a generation bus to provide, for example, auxiliary/parasitic power or station power, power to synchronous condenser motors, or power to run pumped storage pumps, is actually load, not negative generation. Energy injected at load buses by behind the meter generation is actually generation, not negative load.

The zonal load-weighted LMP is calculated by weighting the zone's load bus LMPs by the zone's load bus accounting load. The definition of injections and withdrawals of energy as generation or load affects PJM's calculation of zonal load-weighted LMP.

The MMU recommends that during hours when a generation bus shows a net withdrawal, the energy withdrawal be treated as load, not negative generation, for purposes of calculating load and load-weighted LMP. The MMU also recommends that during hours when a load bus shows a net injection, the energy injection be treated as generation, not negative load, for purposes of calculating generation and load-weighted LMP.

Real-Time Supply

Average offered real-time generation increased by 458 MW, or 0.29 percent, in the first six months of 2016 from 156,679 MW in the first six months of 2015 to 157,137 MW in the first six months of 2016.[19]

In the first six months of 2016, 4,634.9 MW of new capacity were added to PJM and 706 MW of generation were retired.

19 Calculated values shown in Section 3, "Energy Market," are based on unrounded, underlying data and may differ from calculations based on the rounded values shown in tables.

PJM average real-time generation in the first six months of 2016 decreased by 9.1 percent from the first six months of 2015, from 90,097 MW to 86,335 MW.[20]

PJM average real-time supply including imports decreased by 11.3 percent in the first six months of 2016 from the first six months of 2015, from 96,626 MW to 91,219 MW.

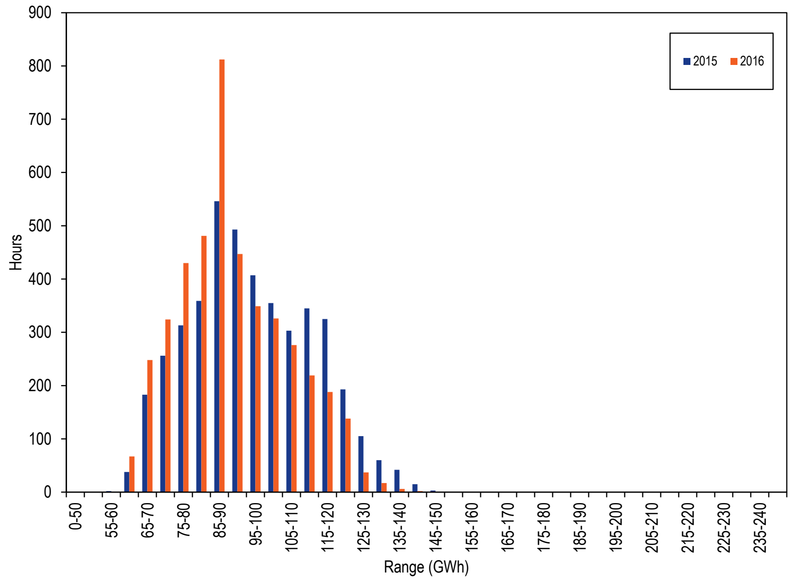
In the PJM Real-Time Energy Market, there are three types of supply offers:

- **Self-Scheduled Generation Offer.** Offer to supply a fixed block of MWh, as a price taker, from a unit that may also have a dispatchable component above the minimum.
- **Dispatchable Generation Offer.** Offer to supply a schedule of MWh and corresponding offer prices from a specific unit.
- **Import.** An import is an external energy transaction scheduled to PJM from another balancing authority. A real-time import must have a valid OASIS reservation when offered, must have available ramp room to support the import, must be accompanied by a NERC Tag, and must pass the neighboring balancing authority checkout process.

PJM Real-Time Supply Duration

Figure 3-6 shows the hourly distribution of PJM real-time generation plus imports for the first six months of 2015 and 2016.

Figure 3-6 Distribution of PJM real-time generation plus imports: January through June, 2015 and 2016[21]



20 Generation data are the net MWh injections and withdrawals MWh at every generation bus in PJM.

21 Each range on the horizontal axis excludes the start value and includes the end value.

PJM Real-Time, Average Supply

Table 3-10 presents summary real-time supply statistics for the first six months of each year for the 17-year period from 2000 through 2016.[22]

Table 3-10 PJM real-time average hourly generation and real-time average hourly generation plus average hourly imports: January through June, 2000 through 2016

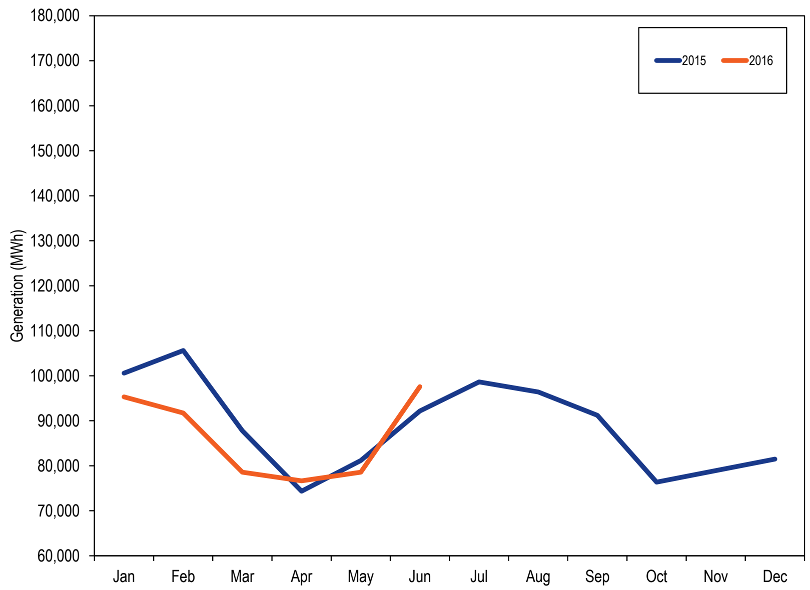
	PJM Real-Time Supply (MWh)				Year-to-Year Change			
	Generation		Generation Plus Imports		Generation		Generation Plus Imports	
Jan-Jun	Generation	Standard Deviation	Supply	Standard Deviation	Generation	Standard Deviation	Supply	Standard Deviation
2000	31,523	5,560	34,190	6,329	NA	NA	NA	NA
2001	29,428	4,679	32,412	4,813	(6.6%)	(15.8%)	(5.2%)	(24.0%)
2002	30,967	5,770	34,730	6,238	5.2%	23.3%	7.2%	29.6%
2003	36,034	6,008	39,644	6,021	16.4%	4.1%	14.1%	(3.5%)
2004	41,430	9,435	45,597	9,699	15.0%	57.0%	15.0%	61.1%
2005	74,365	12,661	79,693	13,242	79.5%	34.2%	74.8%	36.5%
2006	80,249	11,011	84,819	11,574	7.9%	(13.0%)	6.4%	(12.6%)
2007	83,478	12,105	88,150	13,192	4.0%	9.9%	3.9%	14.0%
2008	83,294	12,458	88,824	12,778	(0.2%)	2.9%	0.8%	(3.1%)
2009	77,508	12,961	82,928	13,580	(6.9%)	4.0%	(6.6%)	6.3%
2010	80,702	13,968	85,575	14,455	4.1%	7.8%	3.2%	6.4%
2011	81,483	13,677	86,268	14,428	1.0%	(2.1%)	0.8%	(0.2%)
2012	86,310	13,695	91,526	14,279	5.9%	0.1%	6.1%	(1.0%)
2013	87,974	13,528	93,166	14,277	1.9%	(1.2%)	1.8%	(0.0%)
2014	92,458	15,722	98,186	16,710	5.1%	16.2%	5.4%	17.0%
2015	90,097	16,028	96,626	17,168	(2.6%)	1.9%	(1.6%)	2.7%
2016	86,335	14,576	91,219	15,231	(4.2%)	(9.1%)	(5.6%)	(11.3%)

22 The import data in this table is not available before June 1, 2000. The data that includes imports in 2000 is calculated from the last six months of that year.

PJM Real-Time, Monthly Average Generation

Figure 3-7 compares the real-time, monthly average hourly generation in the first six months of 2016 to 2015.

Figure 3-7 PJM real-time average monthly hourly generation: 2015 through June 2016



Day-Ahead Supply

PJM average day-ahead supply in the first six months of 2016, including INCs and up to congestion transactions, increased by 8.3 percent from the first six months of 2015, from 115,148 MW to 127,748 MW.

PJM average day-ahead supply in the first six months of 2016, including INCs, up to congestion transactions, and imports, increased by 8.2 percent from the first six months of 2015, from 117,612 MW to 129,832 MW. The increase in PJM day-ahead supply was a result of an increase in UTCs beginning in

December 2015 based on a FERC order setting December 8, 2015, as the last effective date for any uplift charges subsequently assigned to UTCs.[23]

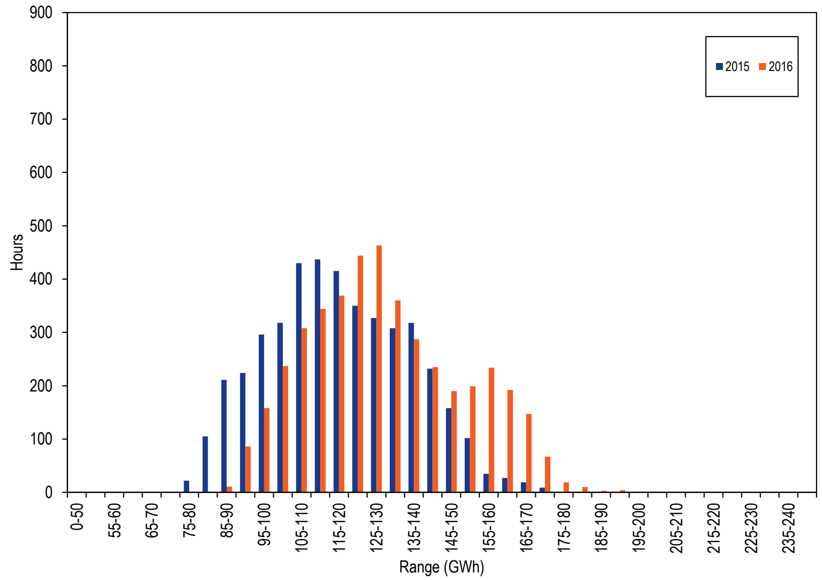
In the PJM Day-Ahead Energy Market, there are five types of financially binding supply offers:

- **Self-Scheduled Generation Offer.** Offer to supply a fixed block of MWh, as a price taker, from a unit that may also have a dispatchable component above the minimum.
- **Dispatchable Generation Offer.** Offer to supply a schedule of MWh and corresponding offer prices from a unit.
- **Increment Offer (INC).** Financial offer to supply MWh and corresponding offer prices. INCs can be submitted by any market participant.
- **Up to Congestion Transaction (UTC).** Conditional transaction that permits a market participant to specify a maximum price spread between the transaction source and sink. An up to congestion transaction is evaluated as a matched pair of an injection and a withdrawal analogous to a matched pair of an INC offer and a DEC bid.
- **Import.** An import is an external energy transaction scheduled to PJM from another balancing authority. An import must have a valid willing to pay congestion (WPC) OASIS reservation when offered. An import energy transaction that clears the Day-Ahead Energy Market is financially binding. There is no link between transactions submitted in the PJM Day-Ahead Energy Market and the PJM Real-Time Energy Market, so an import energy transaction approved in the Day-Ahead Energy Market will not physically flow in real time unless it is also submitted through the real-time energy market scheduling process.

PJM Day-Ahead Supply Duration

Figure 3-8 shows the hourly distribution of PJM day-ahead supply, including increment offers, up to congestion transactions, and imports for the first six months of 2015 and 2016.

Figure 3-8 Distribution of PJM day-ahead supply plus imports: January through June, 2015 and 2016[24]



23 148 FERC ¶ 61,144 (2014).

24 Each range on the horizontal axis excludes the start value and includes the end value.

PJM Day-Ahead, Average Supply

Table 3-11 presents summary day-ahead supply statistics for the first six months of each year of the 17-year period from 2000 through 2016.[25]

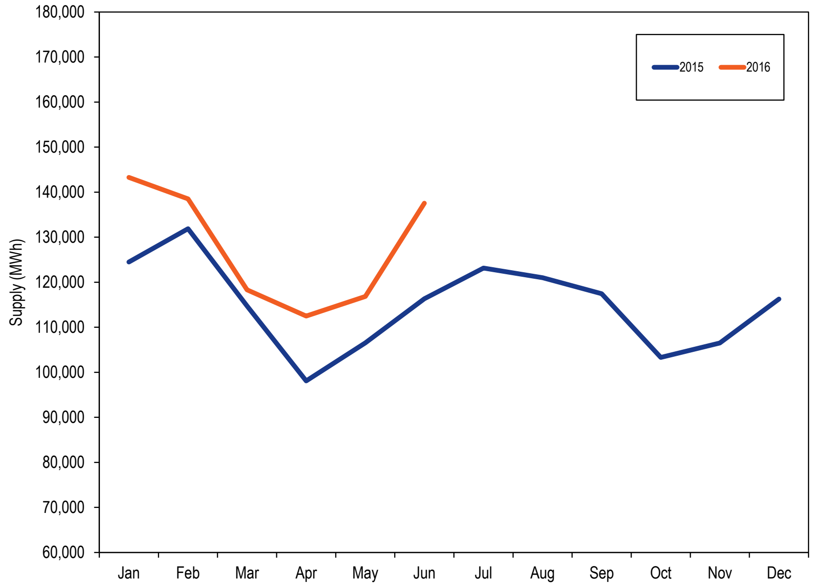
Table 3-11 PJM day-ahead average hourly supply and day-ahead average hourly supply plus average hourly imports: January through June, 2000 through 2016

	PJM Day-Ahead Supply (MWh)				Year-to-Year Change			
	Supply		Supply Plus Imports		Supply		Supply Plus Imports	
Jan-Jun	Supply	Standard Deviation	Supply	Standard Deviation	Supply	Standard Deviation	Supply	Standard Deviation
2000	29,474	5,648	29,645	5,766	NA	NA	NA	NA
2001	26,796	4,305	27,540	4,382	(9.1%)	(23.8%)	(7.1%)	(24.0%)
2002	25,840	10,011	26,398	10,021	(3.6%)	132.5%	(4.1%)	128.7%
2003	36,420	7,000	36,994	7,023	40.9%	(30.1%)	40.1%	(29.9%)
2004	50,089	10,108	50,836	10,171	37.5%	44.4%	37.4%	44.8%
2005	87,855	14,365	89,382	14,395	75.4%	42.1%	75.8%	41.5%
2006	95,562	12,620	97,796	12,615	8.8%	(12.1%)	9.4%	(12.4%)
2007	106,470	14,522	108,815	14,772	11.4%	15.1%	11.3%	17.1%
2008	104,705	14,124	107,169	14,190	(1.7%)	(2.7%)	(1.5%)	(3.9%)
2009	97,607	16,283	100,076	16,342	(6.8%)	15.3%	(6.6%)	15.2%
2010	102,626	18,206	105,463	18,378	5.1%	11.8%	5.4%	12.5%
2011	108,143	16,666	110,656	16,926	5.4%	(8.5%)	4.9%	(7.9%)
2012	132,326	15,710	134,747	15,841	22.4%	(5.7%)	21.8%	(6.4%)
2013	148,381	15,606	150,554	15,830	12.1%	(0.7%)	11.7%	(0.1%)
2014	165,620	13,930	167,939	14,119	11.6%	(10.7%)	11.5%	(10.8%)
2015	115,148	18,849	117,612	18,994	(30.5%)	35.3%	(30.0%)	34.5%
2016	127,748	20,415	129,832	20,554	10.9%	8.3%	10.4%	8.2%

PJM Day-Ahead, Monthly Average Supply

Figure 3-9 compares the day-ahead, monthly average hourly supply, including increment offers and up to congestion transactions, from January 1, 2015, through March 31, 2016.

Figure 3-9 PJM day-ahead monthly average hourly supply: 2015 through June 2016



Real-Time and Day-Ahead Supply

Table 3-12 presents summary statistics for the first six months of 2015 and 2016, for day-ahead and real-time supply. The last two columns of Table 3-12 are the day-ahead supply minus the real-time supply. The first of these columns is the total day-ahead supply less the total real-time supply and the second of these columns is the total physical day-ahead generation less the total physical real-time generation. In the first six months of 2016, up-to congestion transactions were 26.7 percent of the total day-ahead supply compared to 14.8 percent in the first six months of 2015.

25 Since the Day-Ahead Energy Market did not start until June 1, 2000, the day-ahead data for 2000 only includes data for the last six months of that year.

Table 3-12 Day-ahead and real-time supply (MWh): January through June, 2015 and 2016

		Day Ahead					Real Time		Day Ahead Less Real Time	
	Jan-Jun	Generation	INC	Up to Congestion	Imports	Total Supply	Generation	Total Supply	Total Supply	Total Generation
Average	2015	93,011	4,713	17,425	2,464	117,612	90,097	96,626	20,986	2,914
	2016	87,884	5,246	34,615	2,084	129,832	86,335	91,219	38,613	1,549
Median	2015	92,017	4,650	17,190	2,469	116,585	88,510	94,831	21,754	3,507
	2016	85,649	5,108	33,910	2,050	127,289	83,724	88,594	38,695	1,924
Standard Deviation	2015	17,290	694	3,592	426	18,994	16,028	17,168	1,826	1,262
	2016	15,821	1,024	7,097	585	20,554	14,576	15,231	5,323	1,245
Peak Average	2015	101,910	4,863	18,426	2,602	127,801	97,640	104,825	22,976	4,270
	2016	96,366	5,229	36,639	2,151	140,403	93,608	98,917	41,487	2,757
Peak Median	2015	101,652	4,837	18,037	2,613	126,568	96,767	103,701	22,867	4,885
	2016	93,911	5,111	35,778	2,119	136,847	91,296	96,223	40,624	2,615
Peak Standard Deviation	2015	14,167	651	3,604	423	15,794	13,896	14,766	1,027	271
	2016	12,959	951	6,814	670	17,492	12,641	12,982	4,510	318
Off-Peak Average	2015	84,951	4,577	16,518	2,338	108,384	83,265	89,200	19,184	1,685
	2016	80,170	5,260	32,774	2,022	120,218	79,721	84,218	36,000	449
Off-Peak Median	2015	83,297	4,490	16,244	2,306	105,973	81,495	86,632	19,340	1,802
	2016	77,545	5,105	31,677	1,998	116,178	77,265	81,431	34,747	279
Off-Peak Standard Deviation	2015	15,852	704	3,331	388	16,807	14,716	15,755	1,052	1,136
	2016	14,154	1,085	6,845	487	18,288	12,982	13,669	4,619	1,172

Figure 3-10 shows the average hourly cleared volumes of day-ahead supply and real-time supply for 2015. The day-ahead supply consists of day-ahead generation, imports, cleared increment offers and cleared up to congestion transactions. The real-time generation includes generation and imports.

Figure 3-10 Day-ahead and real-time supply (Average hourly volumes): January through June, 2016

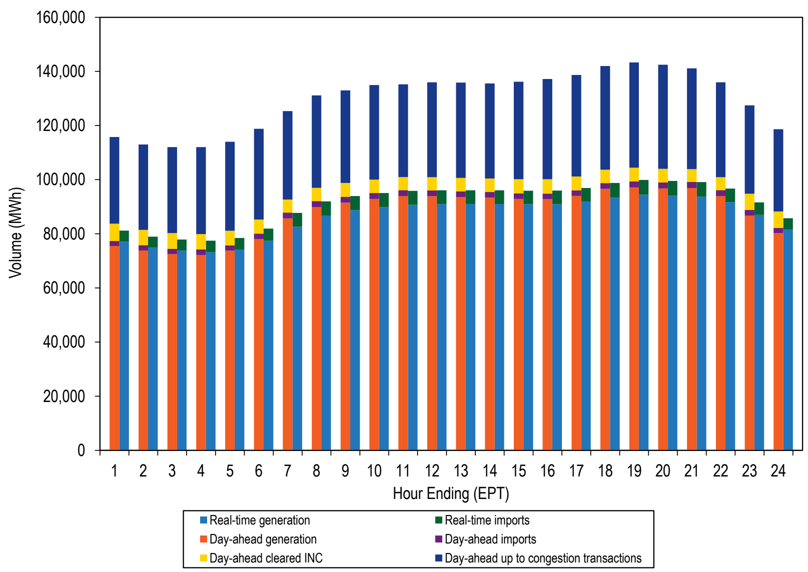


Figure 3-11 Difference between day-ahead and real-time supply (Average daily volumes): 2015 through June 2016

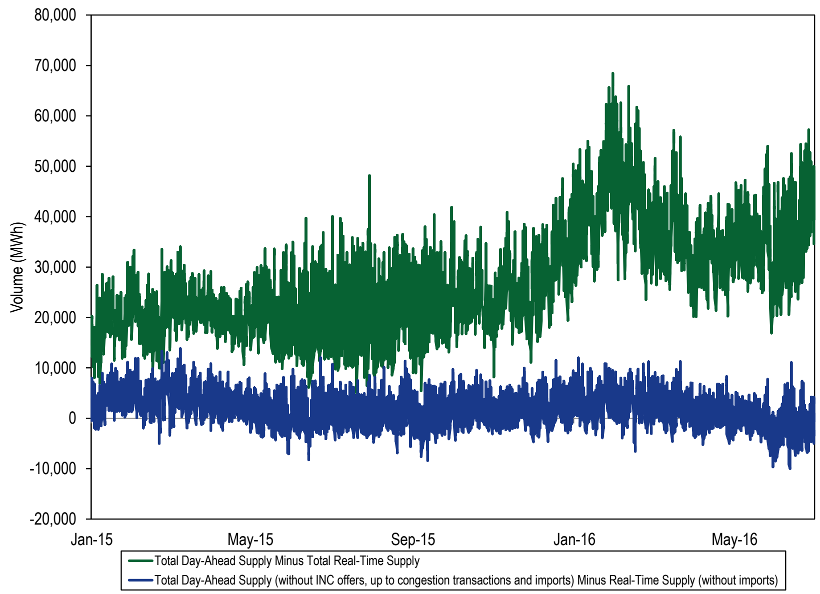
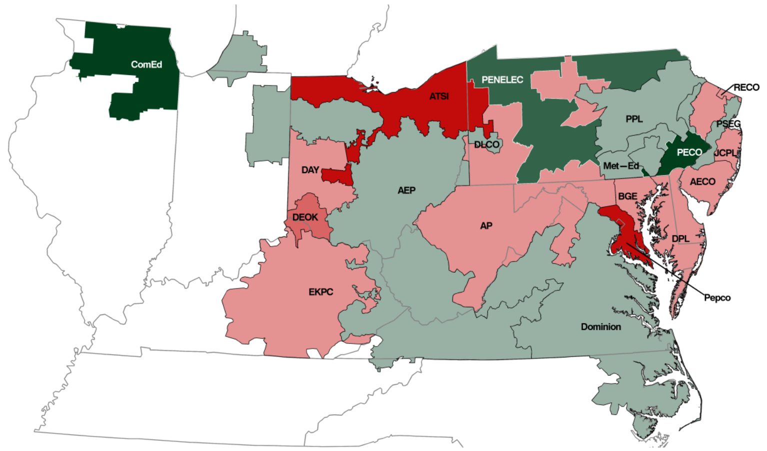


Figure 3-11 shows the difference between the day-ahead and real-time average daily supply for January 1, 2015, through June 30, 2016.

Figure 3-12 shows the difference between the PJM real-time generation and real-time load by zone in the first six months of 2016. Figure 3-12 is color coded on a scale on which red shades represent zones that have less generation than load and green shades represent zones that have more generation than load, with darker shades meaning greater amounts of net generation or load. For example, the Pepco Control Zone has less generation than load, while the PENELEC Control Zone has more generation than load. Table 3-13 shows the difference between the PJM real-time generation and real-time load by zone in the first six months of 2015 and 2016.

Figure 3-12 Map of PJM real-time generation less real-time load by zone: January through June, 2016[26]



Zone	Net Gen Minus Load (GWh)	Zone	Net Gen Minus Load (GWh)	Zone	Net Gen Minus Load (GWh)	Zone	Net Gen Minus Load (GWh)
AECO	(1,436)	ComEd	13,834	DPL	(4,907)	PENELEC	8,215
AEP	3,204	DAY	(1,086)	EKPC	(1,476)	Pepco	(10,084)
AP	(1,382)	DEOK	(6,874)	JCPL	(2,414)	PPL	3,164
ATSI	(12,954)	DLCO	2,130	Met-Ed	3,857	PSEG	2,261
BGE	(4,829)	Dominion	1,171	PECO	12,626	RECO	(682)

26 Zonal real-time generation data for the map and corresponding table is based on the zonal designation for every bus listed in the most current PJM LMP bus model, which can be found at <http://www.pjm.com/markets-and-operations/energy/lmp-model-info.aspx>.

Table 3-13 PJM real-time generation less real-time load by zone (GWh): January through June, 2015 and 2016

Zonal Generation and Load (GWh)						
	Jan-Jun 2015			Jan-Jun 2016		
Zone	Generation	Load	Net	Generation	Load	Net
AECO	2,836.0	5,105.9	(2,269.9)	3,136.9	4,573.0	(1,436.1)
AEP	73,030.8	65,187.9	7,842.9	65,477.0	62,273.2	3,203.9
AP	20,898.6	25,170.3	(4,271.7)	22,296.2	23,678.2	(1,382.0)
ATSI	23,158.8	33,769.7	(10,610.9)	19,488.2	32,441.7	(12,953.5)
BGE	11,084.5	16,454.9	(5,370.4)	10,221.5	15,050.8	(4,829.4)
ComEd	62,304.6	46,795.9	15,508.8	60,544.7	46,710.6	13,834.1
DAY	6,356.2	8,533.2	(2,177.1)	7,284.3	8,370.5	(1,086.2)
DEOK	9,437.7	13,491.7	(4,054.0)	6,218.9	13,092.8	(6,873.9)
DLCO	8,295.3	7,095.3	1,200.0	8,746.4	6,616.2	2,130.2
Dominion	43,431.8	49,298.9	(5,867.0)	47,296.2	46,125.6	1,170.5
DPL	3,827.6	9,540.9	(5,713.3)	3,714.4	8,621.3	(4,906.8)
EKPC	4,529.2	6,447.5	(1,918.3)	4,800.6	6,276.4	(1,475.9)
JCPL	6,253.7	11,312.5	(5,058.8)	8,184.9	10,599.1	(2,414.2)
Met-Ed	11,241.4	7,771.3	3,470.1	11,251.5	7,394.6	3,856.9
PECO	29,003.8	20,228.4	8,775.3	31,762.2	19,136.4	12,625.7
PENELEC	21,850.0	8,804.8	13,045.3	16,511.1	8,296.4	8,214.8
Pepco	5,128.6	15,475.1	(10,346.5)	4,339.3	14,422.9	(10,083.6)
PPL	25,840.0	21,079.1	4,760.9	23,058.7	19,894.5	3,164.2
PSEG	22,781.3	21,110.3	1,671.0	22,692.9	20,432.0	2,260.9
RECO	0.0	731.0	(731.0)	0.0	681.8	(681.8)

Demand

Demand includes physical load and exports and virtual transactions.

Peak Demand

In this section, demand refers to physical load and exports and in the Day-Ahead Energy Market also includes virtual transactions.

The PJM system real-time peak load for the first six months of 2016 was 134,958 MW in the HE 17 on June 20, 2016, which was 8,157 MW, or 5.7 percent, lower than the peak load for the first six months of 2015, which was 143,115MW in the HE 8 on February 20, 2015.

Table 3-14 shows the peak loads for the first six months of 1999 through 2016.

Table 3-14 Actual PJM footprint peak loads: 1999 to 2016[27]

(Jan - Jun)	Date	Hour Ending (EPT)	PJM Load (MW)	Annual Change (MW)	Annual Change (%)
1999	Tue, June 08	17	114,607	NA	NA
2000	Mon, June 26	16	112,028	(2,579)	(2.3%)
2001	Thu, June 28	17	115,808	3,780	3.4%
2002	Mon, June 24	17	122,105	6,297	5.4%
2003	Wed, June 25	17	119,378	(2,727)	(2.2%)
2004	Wed, June 09	17	120,218	840	0.7%
2005	Tue, June 28	16	124,052	3,833	3.2%
2006	Tue, May 30	17	121,165	(2,887)	(2.3%)
2007	Wed, June 27	16	130,971	9,806	8.1%
2008	Mon, June 09	17	130,100	(871)	(0.7%)
2009	Fri, January 16	19	117,169	(12,930)	(9.9%)
2010	Wed, June 23	17	126,188	9,019	7.7%
2011	Wed, June 08	17	144,350	18,162	14.4%
2012	Wed, June 20	18	147,913	3,563	2.5%
2013	Tue, June 25	16	139,779	(8,134)	(5.5%)
2014	Tue, June 17	17	141,673	1,895	1.4%
2015	Fri, February 20	8	143,115	1,441	1.0%
2016	Mon, June 20	17	134,958	(8,157)	(5.7%)

Figure 3-13 shows the peak loads for 1999 through June 2016.

Figure 3-13 PJM footprint calendar year peak loads: 1999 to June 2016

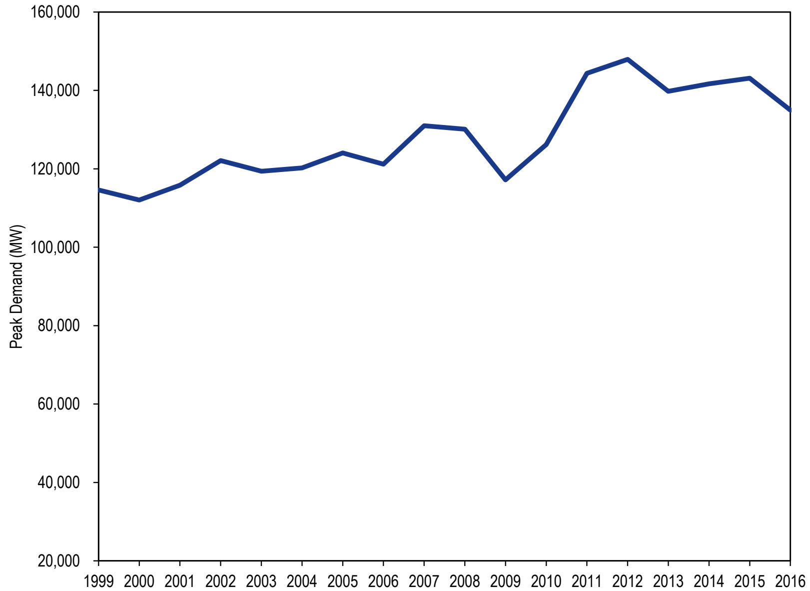
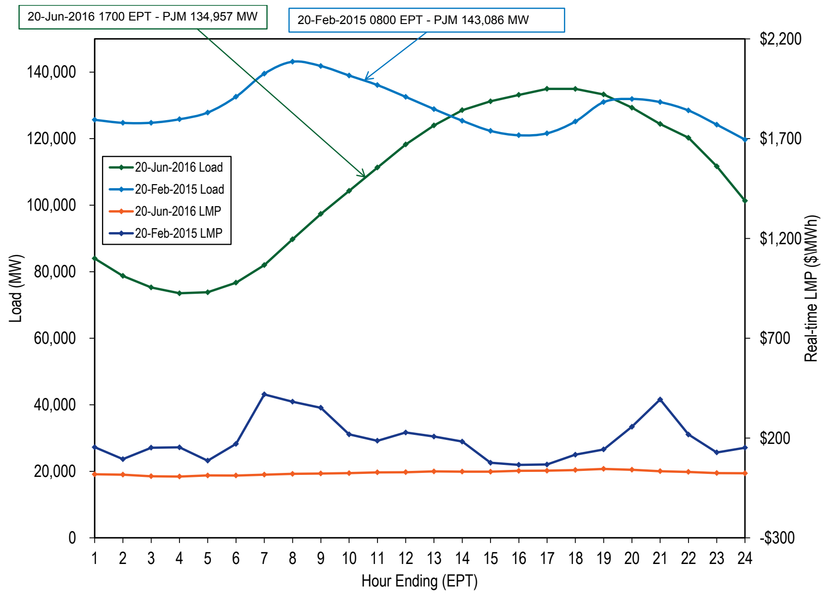


Figure 3-14 compares the peak load days during the first six months of 2015 and 2016. The average hourly real-time LMP peaked at $45.54 on June 20, 2016, and peaked at $418.73 on February 20, 2015.

27 Peak loads shown are eMTR load. See the *MMU Technical Reference for the PJM Markets*, at "Load Definitions" for detailed definitions of load. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

Figure 3-14 PJM peak-load comparison Monday, June 20, 2016 and Friday, February 20, 2015



Real-Time Demand

PJM average real-time load in the first six months of 2016 decreased by 5.3 percent from the first six months of 2015, from 90,586 MW to 85,800 MW.[28]

PJM average real-time demand in the first six months of 2016 decreased 5.3 percent from the first six months of 2015, from 94,782 MW to 89,746 MW.

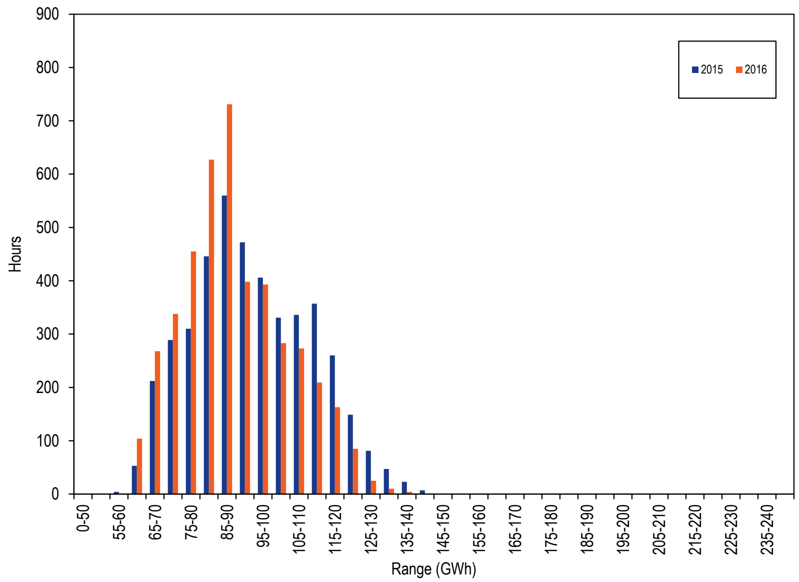
In the PJM Real-Time Energy Market, there are two types of demand:

- **Load.** The actual MWh level of energy used by load within PJM.
- **Export.** An export is an external energy transaction scheduled from PJM to another balancing authority. A real-time export must have a valid OASIS reservation when offered, must have available ramp room to support the export, must be accompanied by a NERC Tag, and must pass the neighboring balancing authority checkout process.

PJM Real-Time Demand Duration

Figure 3-15 shows the hourly distribution of PJM real-time load plus exports for the first six months of 2015 and 2016.[29]

Figure 3-15 Distribution of PJM real-time accounting load plus exports: January through June, 2015 and 2016[30]



28 Load data are the net MWh injections and withdrawals MWh at every load bus in PJM.

29 All real-time load data in Section 3, "Energy Market," "Market Performance: Load and LMP," are based on PJM accounting load. See the *Technical Reference for PJM Markets*, "Load Definitions," for detailed definitions of accounting load. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

30 Each range on the horizontal axis excludes the start value and includes the end value.

PJM Real-Time, Average Load

Table 3-15 presents summary real-time demand statistics for the first six months of 1998 to 2016. Before June 1, 2007, transmission losses were included in accounting load. After June 1, 2007, transmission losses were excluded from accounting load and losses were addressed through marginal loss pricing.[31]

Table 3-15 PJM real-time average hourly load and real-time average hourly load plus average hourly exports: January through June, 1998 through 2016[32]

	PJM Real-Time Demand (MWh)				Year-to-Year Change			
	Load		Load Plus Exports		Load		Load Plus Exports	
Jan-Jun	Load	Standard Deviation	Demand	Standard Deviation	Load	Standard Deviation	Demand	Standard Deviation
1998	27,662	4,703	27,662	4,703	NA	NA	NA	NA
1999	28,714	5,113	28,714	5,113	3.8%	8.7%	3.8%	8.7%
2000	29,649	5,382	29,902	5,511	3.3%	5.3%	4.1%	7.8%
2001	30,180	5,274	32,041	5,103	1.8%	(2.0%)	7.2%	(7.4%)
2002	32,678	6,457	33,969	6,557	8.3%	22.4%	6.0%	28.5%
2003	36,727	6,428	38,775	6,554	12.4%	(0.4%)	14.1%	(0.0%)
2004	41,787	8,999	44,808	10,033	13.8%	40.0%	15.6%	53.1%
2005	71,939	13,603	78,745	13,798	72.2%	51.2%	75.7%	37.5%
2006	77,232	12,003	83,606	12,377	7.4%	(11.8%)	6.2%	(10.3%)
2007	81,110	13,499	86,557	13,819	5.0%	12.5%	3.5%	11.6%
2008	78,685	12,819	85,819	13,242	(3.0%)	(5.0%)	(0.9%)	(4.2%)
2009	75,991	12,899	81,062	13,253	(3.4%)	0.6%	(5.5%)	0.1%
2010	78,106	13,643	83,758	14,227	2.8%	5.8%	3.3%	7.3%
2011	78,823	13,931	84,288	14,046	0.9%	2.1%	0.6%	(1.3%)
2012	84,946	13,941	89,638	13,848	7.8%	0.1%	6.3%	(1.4%)
2013	86,897	13,871	91,199	13,848	2.3%	(0.5%)	1.7%	0.0%
2014	90,529	16,266	96,189	16,147	4.2%	17.3%	5.5%	16.6%
2015	90,586	16,192	94,782	16,589	0.1%	(0.5%)	(1.5%)	2.7%
2016	85,800	14,517	89,746	14,798	(5.3%)	(10.3%)	(5.3%)	(10.8%)

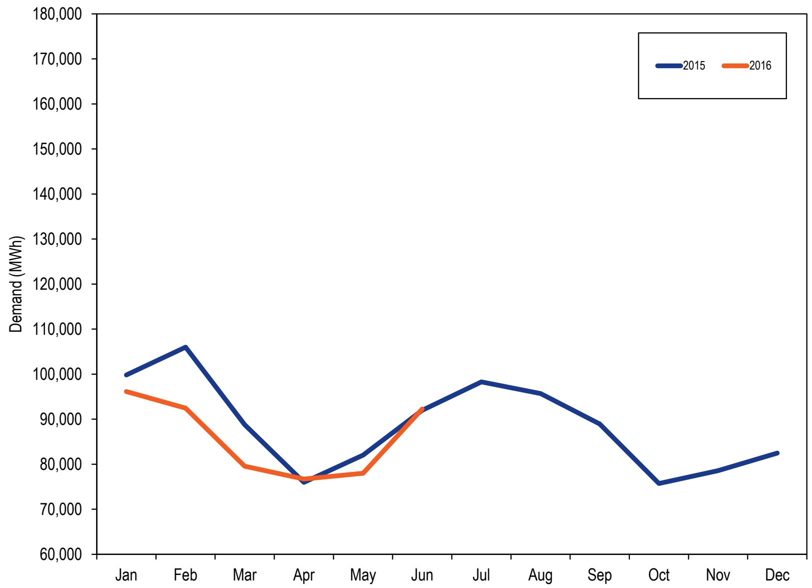
PJM Real-Time, Monthly Average Load

Figure 3-16 compares the real-time, monthly average hourly loads from January 1, 2015, through June 30, 2016.

31 Accounting load is used here because PJM uses accounting load in the settlement process, which determines how much load customers pay for. In addition, the use of accounting load with losses before June 1, and without losses after June 1, 2007, is consistent with PJM's calculation of LMP, which excludes losses prior to June 1 and includes losses after June 1.

32 Export data are not available before June 1, 2000. The export data for 2000 are for the last six months of 2000.

Figure 3-16 PJM real-time monthly average hourly load: January 2015 through June 2016



PJM real-time load is significantly affected by temperature. Figure 3-17 and Table 3-16 compare the PJM monthly heating and cooling degree days in the first six months of 2015 and 2016.[33] Heating degree days decreased 20.6 percent, and cooling degree days decreased 9.8 percent from the first six months of 2015 to 2016.

33 A heating degree day is defined as the number of degrees that a day's average temperature is below 65 degrees F (the temperature below which buildings need to be heated). A cooling degree day is the number of degrees that a day's average temperature is above 65 degrees F (the temperature when people will start to use air conditioning to cool buildings). PJM uses 60 degrees F for a heating degree day as stated in Manual 19.
Heating and cooling degree days are calculated by weighting the temperature at each weather station in the individual transmission zones using weights provided by PJM in Manual 19. Then the temperature is weighted by the real-time zonal accounting load for each transmission zone. After calculating an average hourly temperature across PJM, the heating and cooling degree formulas are used to calculate the daily heating and cooling degree days, which are summed for monthly reporting. The weather stations that provided the basis for the analysis are ABE, ACY, AVP, BWI, CAK, CLE, CMH, CRW, CVG, DAY, DCA, ERI, EWR, FWA, IAD, ILG, IPT, LEX, ORD, ORF, PHL, PIT, RIC, ROA, TOL and WAL.

Figure 3-17 PJM heating and cooling degree days: 2015 and through June 2016

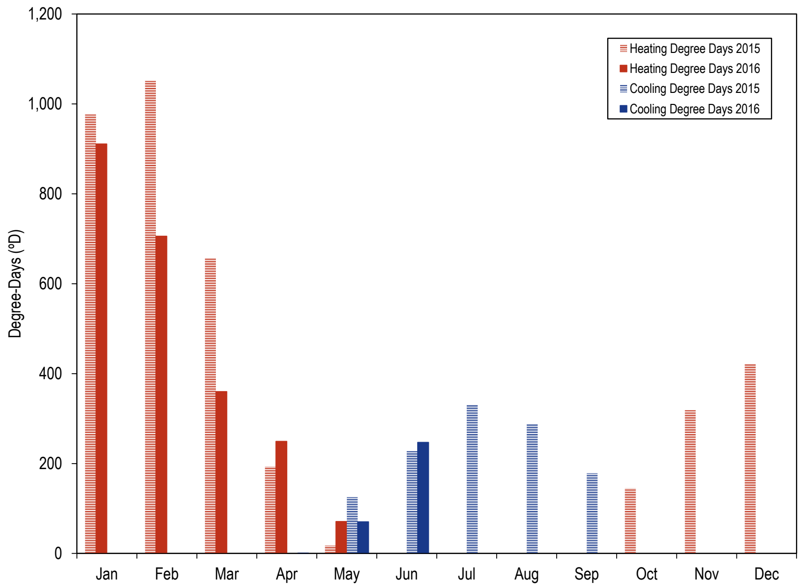


Table 3-16 PJM heating and cooling degree days: 2015 and January through June 2016

	2015		2016		Percent Change	
	Heating Degree Days	Cooling Degree Days	Heating Degree Days	Cooling Degree Days	Heating Degree Days	Cooling Degree Days
Jan	977	0	911	0	(6.7%)	0.0%
Feb	1,051	0	706	0	(32.8%)	0.0%
Mar	656	0	360	0	(45.1%)	0.0%
Apr	193	0	250	1	29.1%	0.0%
May	18	125	71	71	299.6%	(43.7%)
Jun	1	228	0	247	(100%)	8.6%
Jul	0	330	NA	NA	NA	NA
Aug	0	289	NA	NA	NA	NA
Sep	0	179	NA	NA	NA	NA
Oct	145	0	NA	NA	NA	NA
Nov	319	0	NA	NA	NA	NA
Dec	421	0	NA	NA	NA	NA
Total	3,781	1,151	2,298	319	(20.6%)	(72.3%)

Day-Ahead Demand

PJM average day-ahead demand in the first six months of 2016, including DECs and up to congestion transactions, increased by 11.5 percent from the first six months of 2015, from 111,749 MW to 124,576 MW.

PJM average day-ahead demand in the first six months of 2016, including DECs, up to congestion transactions, and exports, increased by 8.4 percent from the first six months of 2015, from 115,294 MW to 127,674 MW.

The reduction in up to congestion transactions (UTC) that had followed a FERC order setting September 8, 2014, as the effective date for any uplift charges subsequently assigned to UTCs, was reversed. There was an increase in up to congestion volume as a result of the expiration of the fifteen month refund period for the proceeding related to uplift charges for UTC transactions.[34]

In the PJM Day-Ahead Energy Market, five types of financially binding demand bids are made and cleared:

- **Fixed-Demand Bid.** Bid to purchase a defined MWh level of energy, regardless of LMP.
- **Price-Sensitive Bid.** Bid to purchase a defined MWh level of energy only up to a specified LMP, above which the load bid is zero.
- **Decrement Bid (DEC).** Financial bid to purchase a defined MWh level of energy up to a specified LMP, above which the bid is zero. A DEC can be submitted by any market participant.
- **Up to Congestion Transaction (UTC).** A conditional transaction that permits a market participant to specify a maximum price spread between the transaction source and sink. An up to congestion transaction is evaluated as a matched pair of an injection and a withdrawal analogous to a matched pair of an INC offer and a DEC bid.
- **Export.** An external energy transaction scheduled from PJM to another balancing authority. An export must have a valid willing to pay congestion (WPC) OASIS reservation when offered. An export energy transaction that clears the Day-Ahead Energy Market is financially binding. There is

34 148 FERC ¶ 61,144 (2014).

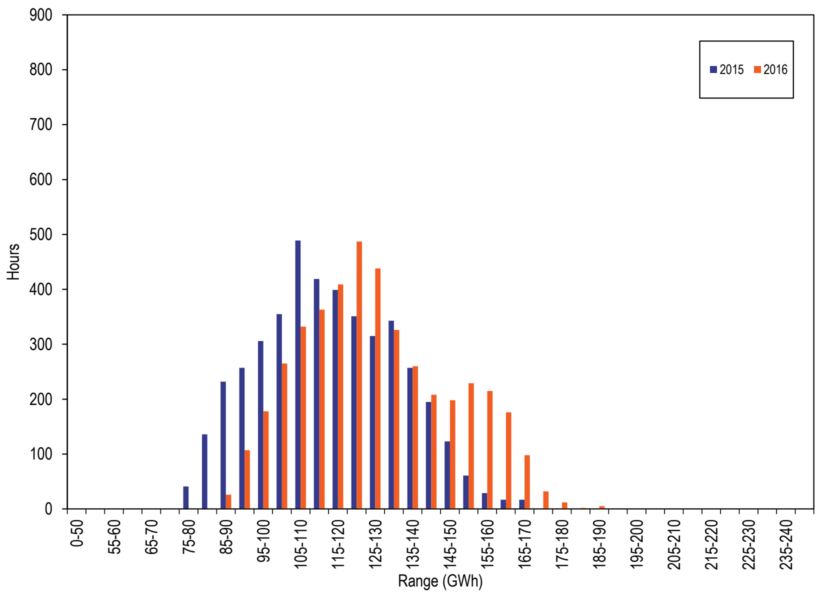
no link between transactions submitted in the PJM Day-Ahead Energy Market and the PJM Real-Time Energy Market, so an export energy transaction approved in the Day-Ahead Energy Market will not physically flow in real time unless it is also submitted through the Real-Time Energy Market scheduling process.

PJM day-ahead demand is the hourly total of the five types of cleared demand bids.

PJM Day-Ahead Demand Duration

Figure 3-18 shows the hourly distribution of PJM day-ahead demand, including decrement bids, up to congestion transactions, and exports for the first six months of 2015 and 2016.

Figure 3-18 Distribution of PJM day-ahead demand plus exports: January through June, 2015 and 2016[35]



35 Each range on the horizontal axis excludes the start value and includes the end value.

PJM Day-Ahead, Average Demand

Table 3-17 presents summary day-ahead demand statistics for the first six months of each year from 2000 to 2016.[36]

Table 3-17 PJM day-ahead average demand and day-ahead average hourly demand plus average hourly exports: January through June, 2000 through 2016

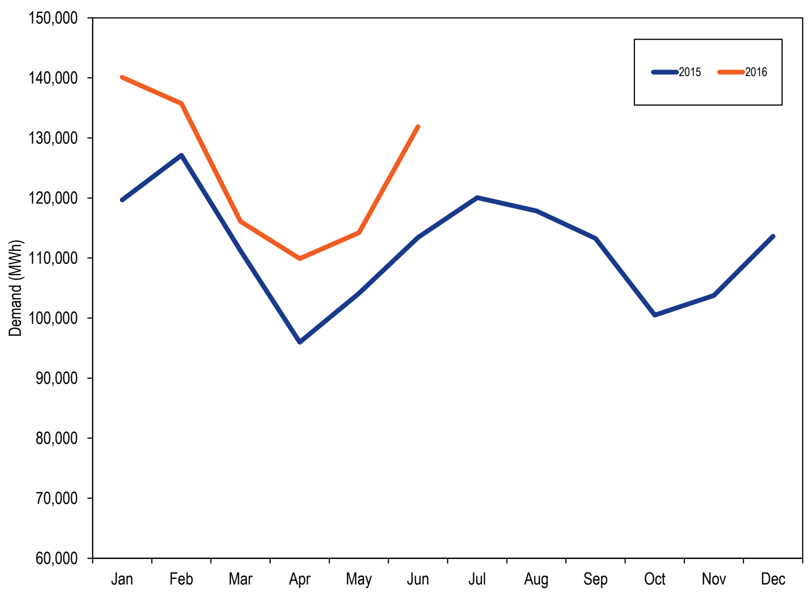
	PJM Day-Ahead Demand (MWh)				Year-to-Year Change			
	Demand		Demand Plus Exports		Demand		Demand Plus Exports	
Jan-Jun	Demand	Standard Deviation	Demand	Standard Deviation	Demand	Standard Deviation	Demand	Standard Deviation
2000	35,448	8,138	35,623	7,982	NA	NA	NA	NA
2001	32,425	6,014	33,075	5,857	(8.5%)	(26.1%)	(7.2%)	(26.6%)
2002	37,561	8,293	37,607	8,311	15.8%	37.9%	13.7%	41.9%
2003	44,391	7,717	44,503	7,704	18.2%	(6.9%)	18.3%	(7.3%)
2004	50,161	10,304	50,596	10,557	13.0%	33.5%	13.7%	37.0%
2005	86,890	14,677	89,388	14,827	73.2%	42.4%	76.7%	40.4%
2006	94,470	12,925	97,460	13,303	8.7%	(11.9%)	9.0%	(10.3%)
2007	104,737	15,019	107,647	15,269	10.9%	16.2%	10.5%	14.8%
2008	100,948	14,255	104,499	14,461	(3.6%)	(5.1%)	(2.9%)	(5.3%)
2009	95,130	15,878	98,001	15,972	(5.8%)	11.4%	(6.2%)	10.4%
2010	99,691	18,097	103,573	18,366	4.8%	14.0%	5.7%	15.0%
2011	105,071	16,452	108,756	16,578	5.4%	(9.1%)	5.0%	(9.7%)
2012	129,881	15,268	133,046	15,436	23.6%	(7.2%)	22.3%	(6.9%)
2013	145,280	15,552	148,414	15,588	11.9%	1.9%	11.6%	1.0%
2014	160,805	13,872	164,740	13,800	10.7%	(10.8%)	11.0%	(11.5%)
2015	111,749	18,074	115,294	18,468	(30.5%)	30.3%	(30.0%)	33.8%
2016	124,576	19,786	127,674	20,027	11.5%	9.5%	10.7%	8.4%

PJM Day-Ahead, Monthly Average Demand

Figure 3-19 compares the day-ahead, monthly average hourly demand, including decrement bids and up to congestion transactions, from January 1, 2015, through June 31, 2016.

36 Since the Day-Ahead Energy Market did not start until June 1, 2000, the day-ahead data for 2000 only includes data for the last six months of that year.

Figure 3-19 PJM day-ahead monthly average hourly demand: January 2015 through June 2016



Real-Time and Day-Ahead Demand

Table 3-18 presents summary statistics for the first six months of 2015 and 2016 day-ahead and real-time demand. The last two columns of Table 3-18 are the day-ahead demand minus the real-time demand. The first such column is the total day-ahead demand less the total real-time demand and the second such column is the total physical day-ahead load (fixed demand plus price-sensitive demand) less the physical real-time load.

Table 3-18 Cleared day-ahead and real-time demand (MWh): January through June, 2015 and 2016

		Day-Ahead						Real-Time		Day-Ahead Less Real-Time	
	Jan-Jun Year	Fixed Demand	Price Sensitive	Dec	Up to Congestion	Exports	Total Demand	Load	Total Demand	Total Demand	Total Load
Average	2015	86,891	3,133	4,300	17,425	3,545	115,294	90,586	94,782	20,512	70,074
	2016	82,536	3,088	4,333	34,615	3,098	127,674	85,800	89,746	37,928	47,872
Median	2015	85,670	3,238	4,079	17,190	3,398	114,177	88,946	93,024	21,153	67,793
	2016	81,050	3,091	4,038	33,910	2,890	125,197	83,572	87,202	37,995	45,577
Standard Deviation	2015	15,378	655	1,279	3,592	1,036	18,468	16,192	16,589	1,878	14,314
	2016	13,649	393	1,310	7,097	931	20,027	14,517	14,798	5,229	9,287
Peak Average	2015	95,165	3,387	4,613	18,426	3,622	125,213	98,598	102,752	22,461	76,137
	2016	90,281	3,323	4,606	36,639	3,115	137,983	93,391	97,241	40,742	52,649
Peak Median	2015	94,032	3,482	4,386	18,037	3,431	123,990	97,538	101,752	22,238	75,301
	2016	88,441	3,292	4,373	35,778	2,976	134,563	90,800	94,662	39,901	50,899
Peak Standard Deviation	2015	12,762	626	1,216	3,604	1,098	15,420	13,713	14,270	1,150	12,563
	2016	10,851	300	1,242	6,814	854	17,044	12,031	12,620	4,424	7,607
Off-Peak Average	2015	79,398	2,903	4,016	16,518	3,474	106,310	83,329	87,564	18,746	64,583
	2016	75,492	2,874	4,084	32,774	3,083	118,298	78,896	82,929	35,369	43,527
Off-Peak Median	2015	77,498	2,951	3,771	16,244	3,345	104,000	81,294	85,179	18,821	62,473
	2016	73,078	2,807	3,745	31,677	2,804	114,390	75,989	80,290	34,100	41,889
Off-Peak Standard Deviation	2015	13,604	592	1,269	3,331	970	16,273	14,785	15,181	1,093	13,692
	2016	12,021	341	1,320	6,845	996	17,810	13,067	13,258	4,553	8,514

Figure 3-20 shows the average hourly cleared volumes of day-ahead demand and real-time demand for the first six months of 2016. The day-ahead demand includes day-ahead load, day-ahead exports, decrement bids and up to congestion transactions. The real-time demand includes real-time load and real-time exports.

Figure 3-20 Day-ahead and real-time demand (Average hourly volumes): January through June, 2016

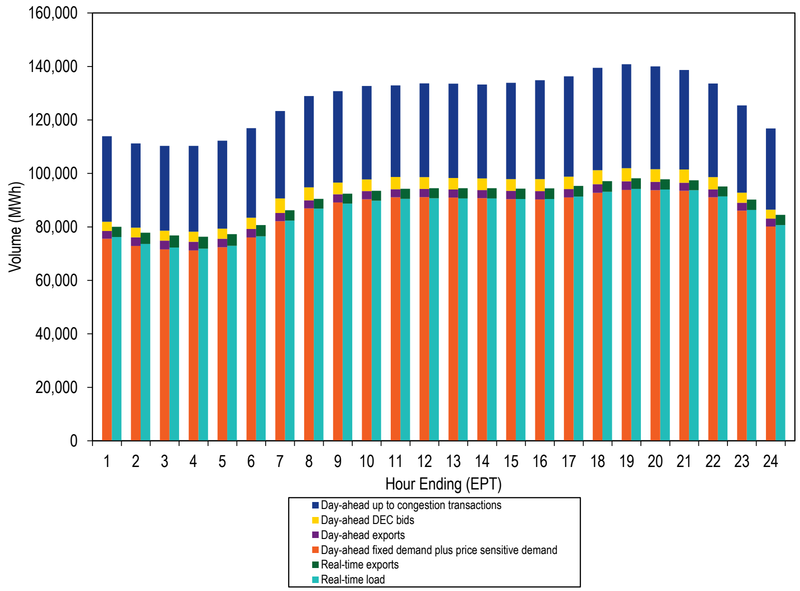


Figure 3-21 Difference between day-ahead and real-time demand (Average daily volumes): 2015 through June 2016

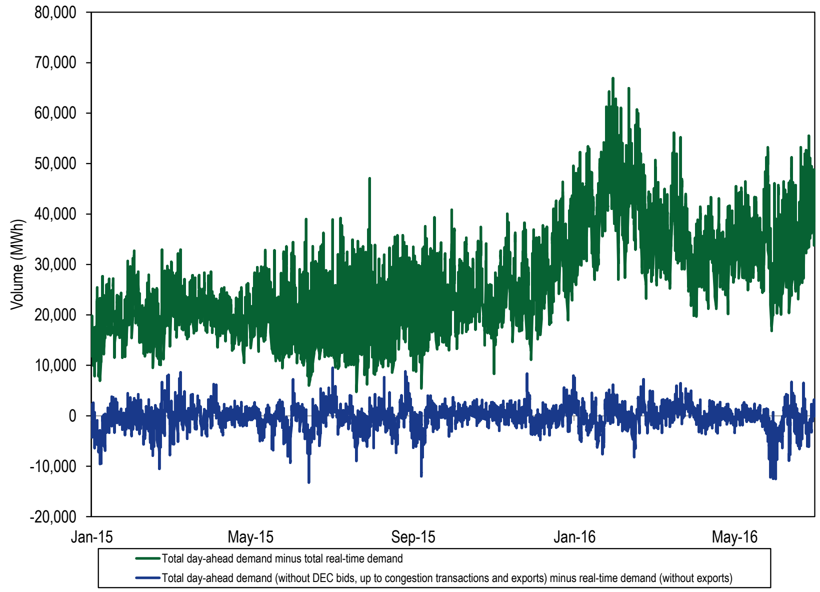


Figure 3-21 shows the difference between the day-ahead and real-time average daily demand from January 1, 2015 through June 30, 2016. There was an increase in up to congestion volume as a result of the expiration of the fifteen month potential refund period for the proceeding related to uplift charges for UTC transactions on December 7, 2015, which increased day-ahead demand.

Supply and Demand: Load and Spot Market

Real-Time Load and Spot Market

Participants in the PJM Real-Time Energy Market can use their own generation to meet load, to sell in the bilateral market or to sell in the spot market in any hour. Participants can both buy and sell via bilateral contracts and buy and sell in the spot market in any hour. If a participant has positive net bilateral transactions in an hour, it is buying energy through bilateral contracts (bilateral purchase). If a participant has negative net bilateral transactions in an hour, it is selling energy through bilateral contracts (bilateral sale). If a participant has positive net spot transactions in an hour, it is buying energy from the spot market (spot purchase). If a participant has negative net spot transactions in an hour, it is selling energy to the spot market (spot sale).

Real-time load is served by a combination of self-supply, bilateral market purchases and spot market purchases. From the perspective of a parent company of a PJM billing organization that serves load, its load could be supplied by any combination of its own generation, net bilateral market purchases and net spot market purchases. In addition to directly serving load, load serving entities can also transfer their responsibility to serve load to other parties through eSchedules transactions referred to as wholesale load responsibility (WLR) or retail load responsibility (RLR) transactions. When the responsibility to serve load is transferred via a bilateral contract, the entity to which the responsibility is transferred becomes the load serving entity. Supply from its own generation (self-supply) means that the parent company is generating power from plants that it owns in order to meet demand. Supply from bilateral purchases means that the parent company is purchasing power under bilateral contracts from a nonaffiliated company at the same time that it is meeting load. Supply from spot market purchases means that the parent company is generating less power from owned plants and/or purchasing less power under bilateral contracts than required to meet load at a defined time and, therefore, is purchasing the required balance from the spot market.

The PJM system's reliance on self-supply, bilateral contracts and spot purchases to meet real-time load is calculated by summing across all the parent companies of PJM billing organizations that serve load in the Real-Time Energy Market for each hour. Table 3-19 shows the monthly average share of real-time load served by self-supply, bilateral contracts and spot purchase in 2015 and the first six months of 2016 based on parent company. In the first six months of 2016, 8.4 percent of real-time load was supplied by bilateral contracts, 26.8 percent by spot market purchase and 64.8 percent by self-supply. Compared with the first six months of 2015, reliance on bilateral contracts increased by 1.9 percentage points, reliance on spot supply decreased by 8.9 percentage points and reliance on self-supply increased by 7.0 percentage points.

Table 3-19 Monthly average percentage of real-time self-supply load, bilateral-supply load and spot-supply load based on parent companies: January 2015 through June 2016[37]

	2015			2016			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	7.1%	32.1%	60.8%	7.1%	28.8%	64.2%	0.0%	(3.3%)	3.3%
Feb	6.6%	32.7%	60.7%	7.5%	28.6%	63.9%	0.9%	(4.1%)	3.2%
Mar	6.2%	34.8%	59.1%	7.6%	29.8%	62.7%	1.4%	(5.0%)	3.6%
Apr	6.6%	37.2%	56.1%	9.2%	24.9%	65.9%	2.5%	(12.3%)	9.8%
May	5.8%	35.9%	58.3%	9.1%	24.2%	66.8%	3.3%	(11.8%)	8.5%
Jun	6.6%	41.3%	52.0%	10.0%	24.3%	65.7%	3.4%	(17.0%)	13.7%
Jul	6.9%	33.8%	59.3%						
Aug	7.0%	28.8%	64.2%						
Sep	7.0%	29.3%	63.7%						
Oct	7.5%	30.2%	62.3%						
Nov	7.2%	29.8%	63.0%						
Dec	7.9%	28.9%	63.3%						
Annual	6.8%	32.9%	60.2%	8.4%	26.8%	64.8%	1.5%	(6.1%)	4.6%

Day-Ahead Load and Spot Market

In the PJM Day-Ahead Energy Market, participants can not only use their own generation, bilateral contracts and spot market purchases to supply their load serving obligation, but can also use virtual resources to meet their load serving obligations in any hour. Virtual supply is treated as supply in the day-ahead analysis and virtual demand is treated as demand in the day-ahead analysis.

The PJM system's reliance on self-supply, bilateral contracts, and spot purchases to meet day-ahead demand (cleared fixed-demand, price-sensitive load and decrement bids) is calculated by summing across all the parent companies of PJM billing organizations that serve demand in the Day-Ahead Energy Market for each hour. Table 3-20 shows the monthly average share of day-ahead demand served by self-supply, bilateral contracts and spot purchases in 2015 through March 2016, based on parent companies. In the first six months of 2016, 8.5 percent of day-ahead demand was supplied by bilateral contracts, 25.7 percent by spot market purchases, and 65.7 percent

37 Table 3-19 and Table 3-20 were calculated as of July 14, 2016. The values may change slightly as billing values are updating by PJM.

by self-supply. Compared with the first six months of 2015, reliance on bilateral contracts decreased by 1.3 percentage points, reliance on spot supply increased by 0.6 percentage points, and reliance on self-supply increased by 0.8 percentage points.

Table 3-20 Monthly average percentage of day-ahead self-supply demand, bilateral supply demand, and spot-supply demand based on parent companies: 2015 through June 2016

	2015			2016			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	10.5%	25.5%	64.0%	8.1%	26.2%	65.7%	(2.4%)	0.7%	1.7%
Feb	9.9%	25.2%	64.9%	8.4%	25.8%	65.8%	(1.5%)	0.6%	0.9%
Mar	9.3%	27.8%	62.9%	7.8%	27.8%	64.4%	(1.5%)	(0.0%)	1.5%
Apr	9.5%	30.3%	60.2%	9.8%	24.6%	65.7%	0.2%	(5.7%)	5.5%
May	9.1%	27.9%	63.0%	9.6%	24.9%	65.6%	0.5%	(3.0%)	2.6%
Jun	8.1%	28.2%	63.8%	8.4%	25.2%	66.5%	0.3%	(3.0%)	2.7%
Jul	8.5%	27.2%	64.3%						
Aug	8.2%	26.9%	64.9%						
Sep	7.9%	27.6%	64.4%						
Oct	8.5%	26.5%	65.0%						
Nov	8.3%	26.1%	65.6%						
Dec	9.3%	25.8%	64.9%						
Annual	8.9%	27.0%	64.0%	8.6%	25.8%	65.6%	(0.3%)	(1.3%)	1.6%

Market Behavior

Offer Capping for Local Market Power

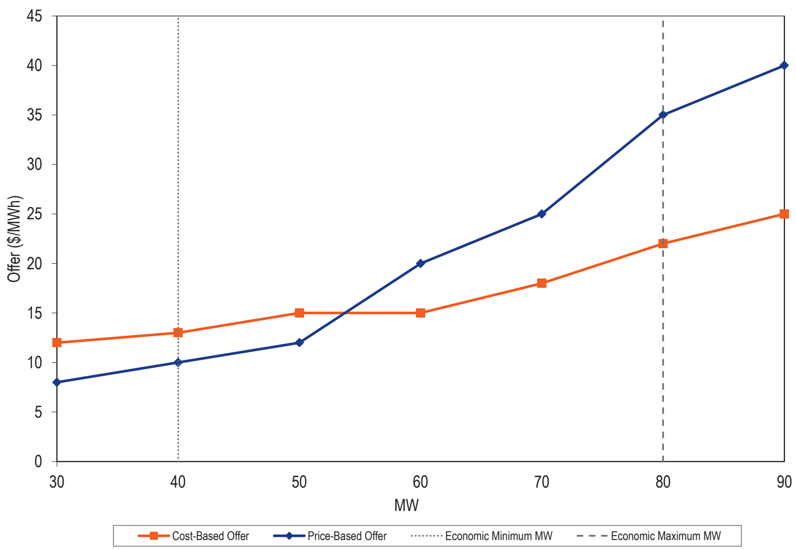
In the PJM Energy Market, offer capping occurs as a result of structurally noncompetitive local markets and noncompetitive offers in the Day-Ahead and Real-Time Energy Markets. PJM also uses offer capping for units that are committed for reliability reasons, specifically for providing black start and reactive service as well as for conservative operations. There are no explicit rules governing market structure or the exercise of market power in the aggregate energy market. PJM's market power mitigation goals have focused on market designs that promote competition and that limit local market power mitigation to situations where the local market structure is not competitive and thus where market design alone cannot mitigate market power.

The analysis of the application of the three pivotal supplier test demonstrates that it is working for most hours to exempt owners when the local market structure is competitive and to offer cap owners when the local market structure is noncompetitive. However, there are some issues with the application of mitigation in the Day-Ahead Energy Market and the Real-Time Energy Market when market sellers fail the TPS test. There is no tariff or manual language that defines in detail the application of the TPS test and offer capping in the Day-Ahead Energy Market and the Real-Time Energy Market.

In both the Day-Ahead and Real-Time Energy Markets, generators have the ability to avoid mitigation by using varying markups in their price-based offers, offering different operating parameters in their price-based and cost-based offers, and using different fuels in their price-based and cost-based offers. These issues can be resolved by simple rule changes.

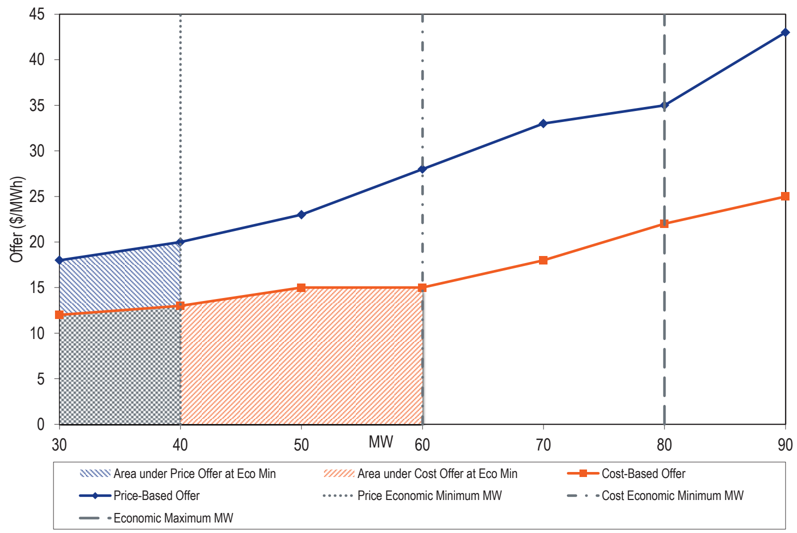
When an owner fails the TPS test, the units offered by the owner that are committed to provide relief are committed on the cheaper of cost or price-based offers. With the ability to submit offer curves with varying markups at different output levels in the price-based offer, units can avoid mitigation by using a low markup at low output levels and a high markup at higher output levels. Figure 3-22 shows an example of offers from a unit that has a negative markup at the economic minimum MW level and a positive markup at the economic maximum MW level. The result would be that a unit that failed the TPS test would be committed on its price-based offer even though the price-based offer is higher than cost at higher output levels and includes positive markups, inconsistent with the explicit goal of local market power mitigation.

Figure 3-22 Offers with varying markups at different MW output levels



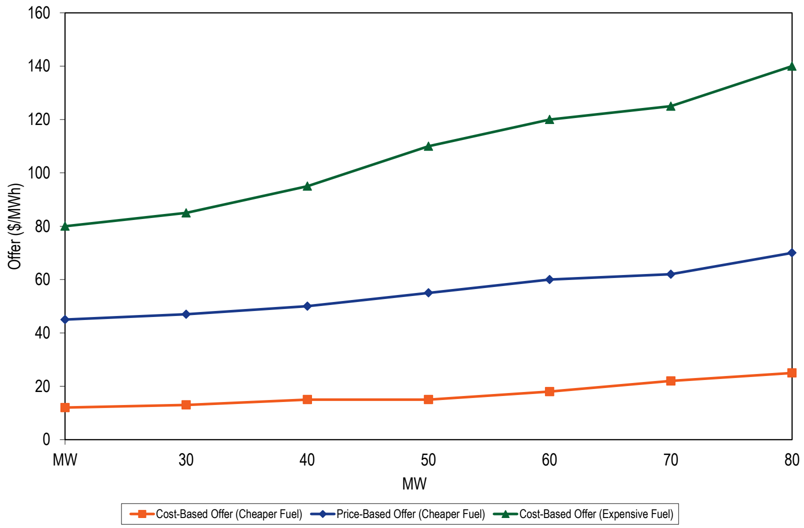
Offering a different economic minimum MW level, different minimum run times, different start up and notification times on the cost-based and price-based offers can also be used to avoid mitigation. For example, a unit may offer its price-based offer with a negative markup, but have a longer minimum run time (MRT) on the price-based offer. For example, a unit may offer a lower economic minimum MW level on the price-based offer than the cost-based offer. Such a unit may appear to be cheaper to commit on the price-based offer even with a positive markup because the total cost of commitment (calculated as a product of MW and the offer in dollars per MWh plus the startup and no-load cost) can be lower on price-based offer at the lower economic minimum level compared to cost-based offer at a higher economic minimum level. Figure 3-23 shows an example of offers from a unit that has a positive markup and a price-based offer with a lower economic minimum MW than the cost-based offer. The cost of commitment (area under the curve) for this unit is lower on the price-based offer than on the cost-based offer. However, the price-based offer includes a positive markup and could result in setting the market price at a noncompetitive level even after the resource owner fails the TPS test.

Figure 3-23 Offers with a positive markup but different economic minimum MW



In case of dual fuel units, if the price-based offer uses a cheaper fuel and the cost-based offer uses a more expensive fuel, the price-based offer will appear to be lower cost even when it includes a markup. Figure 3-24 shows an example of offers by a dual fuel unit, where the active cost-based offer uses a more expensive fuel and the price-based offer uses a cheaper fuel and includes a markup.

Figure 3-24 Dual fuel unit offers



These issues can be solved by simple rule changes.[38] The MMU recommends that markup of price based offers over cost-based offers be constant across the offer curve, that there be at least one cost-based offer using the same fuel as the available price-based offer, and that operating parameters on parameter limited schedules (PLS) be at least as flexible as price-based non-PLS offers.

Levels of offer capping have historically been low in PJM, as shown in Table 3-21. The offer capping percentages shown in Table 3-21 include units that are committed to provide constraint relief whose owners failed the TPS test in the energy market as well as units committed as part of conservative operations, excluding units that were committed for providing black start and reactive service.

Table 3-21 Offer capping statistics – energy only: January through June, 2012 to 2016

	Real-Time		Day-Ahead	
(Jan-Jun)	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2012	1.0%	0.5%	0.1%	0.1%
2013	0.3%	0.1%	0.1%	0.0%
2014	0.7%	0.3%	0.2%	0.1%
2015	0.5%	0.2%	0.2%	0.2%
2016	0.3%	0.2%	0.1%	0.0%

Table 3-22 shows the offer capping percentages including units committed to provide constraint relief and units committed to provide black start service and reactive support. The units that are committed and offer capped for black start service and reactive support reasons increased from 2012 through 2013. Before 2011, the units that ran to provide black start service and reactive support were generally economic in the energy market. From 2011 through 2013, the percentage of hours when these units were not economic (and were therefore committed on their cost schedule for reliability reasons) increased. This trend reversed in 2014, 2015 and 2016 because higher LMPs (in the first six months) resulted in the increased economic dispatch of black start and reactive service resources. As of April 2015, the Automatic Load Rejection (ALR) units that were committed for black start previously no longer provide black start service, and are not included in the offer capping statistics for black start. PJM also created closed loop interfaces to, in some cases, model reactive constraints. The result was higher LMPs, which increased economic dispatch, which contributed to the reduction in units offer capped for reactive support. In instances where units are now committed for the modeled closed loop interface constraints, they are considered offer capped for providing constraint relief. They are included in the offer capping percentages in Table 3-21.

38 The MMU proposed these offer rule changes as part of a broader reform to address generator offer flexibility and associated impact on market power mitigation rules in the Generator Offer Flexibility Senior Task Force (GOFSTF).

Table 3-22 Offer capping statistics for energy and reliability: January through June, 2012 to 2016

	Real-Time		Day-Ahead	
(Jan-Jun)	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2012	1.4%	0.8%	0.1%	0.1%
2013	2.6%	2.1%	3.0%	2.0%
2014	1.1%	0.7%	0.7%	0.5%
2015	1.0%	1.0%	0.8%	0.9%
2016	0.4%	0.2%	0.1%	0.1%

Table 3-23 shows the offer capping percentages for units committed to provide black start service and reactive support. The data in Table 3-23 is the difference between the offer cap percentages shown in Table 3-22 and Table 3-21.

Table 3-23 Offer capping statistics for reliability: January through June, 2012 to 2016

	Real-Time		Day-Ahead	
(Jan-Jun)	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2012	0.4%	0.3%	0.0%	0.0%
2013	2.3%	2.0%	2.9%	2.0%
2014	0.4%	0.4%	0.5%	0.4%
2015	0.5%	0.7%	0.6%	0.7%
2016	0.0%	0.0%	0.0%	0.0%

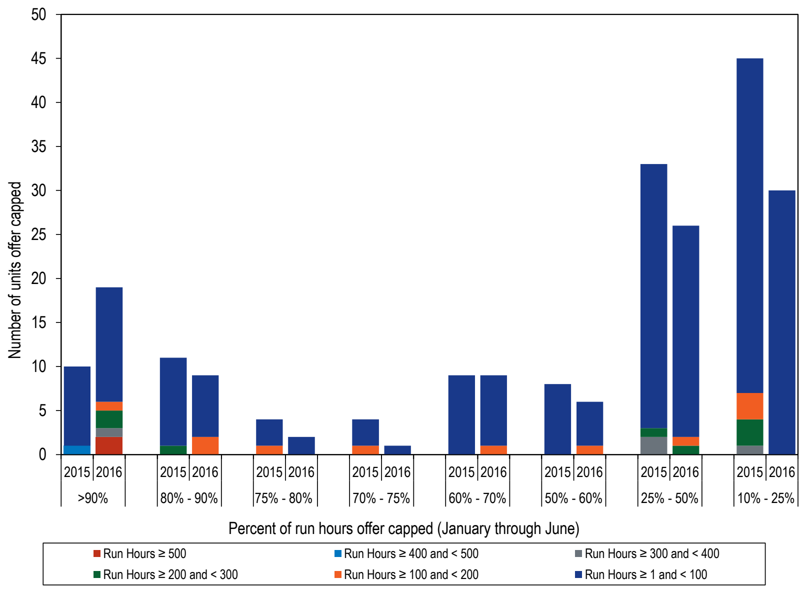
Table 3-24 presents data on the frequency with which units were offer capped in the first six months of 2015 and 2016 for failing the TPS test to provide energy for constraint relief in the Real-Time Energy Market. Table 3-24 shows that nineteen units were offer capped for 90 percent or more of their run hours in the first six months of 2016 compared to ten in the first six months of 2015.

Table 3-24 Real-time offer capped unit statistics: January through June, 2015 and 2016

		Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	(Jan - Jun)	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	2016	2	0	1	2	1	13
	2015	0	1	0	0	0	9
80% and < 90%	2016	0	0	0	0	2	7
	2015	0	0	0	1	0	10
75% and < 80%	2016	0	0	0	0	0	2
	2015	0	0	0	0	1	3
70% and < 75%	2016	0	0	0	0	0	1
	2015	0	0	0	0	1	3
60% and < 70%	2016	0	0	0	0	1	8
	2015	0	0	0	0	0	9
50% and < 60%	2016	0	0	0	0	1	5
	2015	0	0	0	0	0	8
25% and < 50%	2016	0	0	0	1	1	24
	2015	0	0	2	1	0	30
10% and < 25%	2016	0	0	0	0	0	30
	2015	0	0	1	3	3	38

Figure 3-25 shows the frequency with which units were offer capped in the first six months of 2015 and 2016 for failing the TPS test to provide energy for constraint relief in the Real-Time Energy Market.

Figure 3-25 Real-time offer capped unit statistics: January through June, 2015 and 2016



TPS Test Statistics

In the first six months of 2016, the AECO, AEP, AP, BGE, ComEd, Dominion, DPL, JCPL, PECO, PENELEC, and PSEG control zones experienced congestion resulting from one or more constraints binding for 50 or more hours or resulting from an interface constraint. The ATSI, DAY, DEOK, DLCO, EKPC, Met-Ed, Pepco, PPL and RECO control zones did not have constraints binding for 50 or more hours in the first six months of 2016. Table 3-25 shows that AEP, AP, BGE, ComEd, and PSEG were the control zones that experienced congestion resulting from one or more constraints binding for 50 or more hours or resulting from an interface constraint that was binding for one or more hours in every year in the first six months of 2009 through 2016.

Table 3-25 Numbers of hours when control zones experienced congestion resulting from one or more constraints binding for 50 or more hours or from an interface constraint: January through June, 2009 through 2016

	(Jan - Jun)							
	2009	2010	2011	2012	2013	2014	2015	2016
AECO	149	69	88	0	0	0	0	383
AEP	932	355	1,228	322	811	1,773	1,902	471
AP	198	410	52	113	51	170	451	79
ATSI	101	0	0	1	70	403	464	0
BGE	90	154	184	1,556	316	1,142	3,079	4,923
ComEd	576	1,406	153	845	1,678	1,729	1,727	2,910
DEOK	0	0	0	58	0	0	69	0
DLCO	156	342	0	209	0	281	747	0
Dominion	310	589	659	200	0	52	1,422	647
DPL	0	0	0	126	142	560	1,199	1,399
EKPC	0	0	0	0	0	65	0	0
JCPL	0	0	0	0	0	0	79	168
Met-Ed	0	0	0	68	0	0	182	0
PECO	59	0	130	53	256	944	485	732
PENELEC	55	0	0	0	0	1,441	1,385	551
Pepco	0	0	59	203	85	39	0	0
PPL	176	0	52	146	261	147	0	0
PSEG	438	479	605	316	1,462	2,023	2,591	52

The local market structure in the Real-Time Energy Market associated with each of the frequently binding constraints was analyzed using the three pivotal supplier results in the first six months of 2016.[39] The three pivotal supplier (TPS) test is applied every time the system solution indicates that out of merit resources are needed to relieve a transmission constraint. Only uncommitted resources, which would be started to relieve the transmission constraint, are subject to offer capping. Already committed units that can provide incremental relief cannot be offer capped. The results of the TPS test are shown for tests that could have resulted in offer capping and tests that resulted in offer capping.

Overall, the results confirm that the three pivotal supplier test results in offer capping when the local market is structurally noncompetitive and

39 See the *MMU Technical Reference for PJM Markets*, at "Three Pivotal Supplier Test" for a more detailed explanation of the three pivotal supplier test. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>

does not result in offer capping when that is not the case. Local markets are noncompetitive when the number of suppliers is relatively small.

Table 3-26 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owners passing and failing for the transfer interface constraints.

Table 3-26 Three pivotal supplier test details for interface constraints: January through June, 2016

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
AEP - DOM	Peak	537	867	10	0	10
	Off Peak	372	548	10	0	10
Bedington - Black Oak	Peak	132	215	12	3	9
	Off Peak	91	121	10	2	8
Western	Peak	157	232	12	4	8
	Off Peak	0	0	0	0	0
Warren	Peak	37	38	1	0	1
	Off Peak	49	57	1	0	1

Table 3-27 Summary of three pivotal supplier tests applied for interface constraints: January through June, 2016

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
AEP - DOM	Peak	6	3	50%	2	33%	67%
	Off Peak	19	3	16%	2	11%	67%
Bedington - Black Oak	Peak	225	21	9%	4	2%	19%
	Off Peak	150	11	7%	5	3%	45%
Western	Peak	12	2	17%	1	8%	50%
	Off Peak	0	0	0%	0	0%	0%
Warren	Peak	149	0	0%	0	0%	0%
	Off Peak	13	0	0%	0	0%	0%

The three pivotal supplier test is applied every time the PJM market system solution indicates that incremental relief is needed to relieve a transmission constraint. While every system solution that requires incremental relief to transmission constraints will result in a test, not all tested providers of effective supply are eligible for capping. Only uncommitted resources, which would be started as a result of incremental relief needs, are eligible to be offer capped. Already committed units that can provide incremental relief cannot, regardless of test score, be switched from price to cost offers. Table 3-27 provides, for the identified interface constraints, information on total tests applied, the subset of three pivotal supplier tests that could have resulted in the offer capping of uncommitted units and the portion of those tests that did result in offer capping uncommitted units.

Parameter Limited Schedules

All capacity resources in PJM are required to submit at least one cost-based offer. All cost-based offers, submitted by resources that are not capacity performance resources, are parameter limited in accordance with the Parameter Limited Schedule (PLS) matrix or to the level of a prior approved exception.[40] During the delivery year 2016-2017, all cost-based offers, submitted by capacity performance resources, are parameter limited in accordance with predetermined unit specific parameter limits. All capacity resources that choose to offer price-based schedules are required to make available at least one price-based parameter limited schedule (price-based PLS schedule). For resources that are not capacity performance resources, this schedule is to be used by PJM for committing generation resources when a maximum emergency generation alert is declared. For capacity performance resources, the price-based parameter

40 See PJM, OATT, § 6.6 Minimum Generator Operating Parameters - Parameter-Limited Schedules, (September 10, 2014), pp. 1937- 1940.

limited schedule is to be used by PJM for committing generation resources when hot weather and cold weather alerts are declared.

During the extreme cold weather conditions in the first three months of 2016 as well as 2015 and 2014, a number of gas fired generators requested temporary exceptions to parameter limits for their parameter limited schedules due to restrictions imposed by natural gas pipelines. The parameters that were affected because of gas pipeline restrictions include minimum run time (MRT) and turn down ratio (TDR, ratio of economic maximum MW to economic minimum MW). When pipelines issue critical notices and enforce ratable take requirements, generators may be forced to nominate an equal amount of gas for each hour in a 24 hour period, with penalties for deviating from the nominated quantity. This led to requests for 24 hour minimum run times and turn down ratios close to 1.0, to avoid deviations from the hourly nominated quantity.

Key parameters like startup and notification time were not included in the PLS matrix in the first six months of 2016 and prior periods. Some resource owners notified PJM that they needed extended notification times based on the claimed necessity for generation owners to nominate gas prior to gas nomination cycle deadlines. Startup and notification times are limited for Capacity Performance resources beginning June 1, 2016, in accordance with predetermined unit specific parameter limits. The unit specific parameter limits for Capacity Performance resources were based on default minimum operating parameter limits posted by PJM by technology type. These default parameters were based on analysis by the MMU. Market participants could request an adjustment to the default values by submitting documentation to support the physical operating constraints of their units, which was reviewed by PJM and the MMU. The default minimum operating parameter limits or an approved adjusted values are used by Capacity Performance resources for their parameter limited schedules.

Currently, there are no rules in the PJM tariff or manuals that limit the nonparameter attributes of price-based PLS offers. The intent of the price-based PLS offer is to prevent the exercise of market power during high demand conditions by preventing units from offering inflexible operating parameters in order to extract higher market revenues or higher uplift payments. However, a generator can include a higher markup in the price-based PLS offer than in the price-based non-PLS schedule. The result is that the offer is higher and market prices are higher as a result of the exercise of market power using the PLS offer. This defeats the purpose of requiring price-based PLS offers.

The MMU recommends that in order to ensure rigorous market power mitigation when the TPS test is failed, the operating parameters in the cost-based offer and the price-based parameter limited schedule (PLS) offer be at least as flexible as the operating parameters in the available non-PLS price-based offer, and that the price-MW pairs in the price-based PLS offer be exactly equal to the price-based non-PLS offer.

Parameter Limited Schedules under Capacity Performance

Beginning in delivery year 2016/2017, resources that have Capacity Performance (CP) commitments are required to submit, in their parameter limited schedules (cost-based offers and price-based PLS offers), unit specific parameters that reflect the physical capability of the technology type of the resource. In its order on Capacity Performance, the Commission determined that resources should be able to reflect actual constraints based on not just the resource physical constraints, but also other constraints, such as contractual limits that are not based on the physical characteristics of the generator.[41] The Commission found that it is unjust and unreasonable to not provide uplift payments to resources with parameters based on non-physical constraints.[42] The Commission directed PJM to submit tariff language to establish a process through which resources that operate outside the defined unit-specific parameter limits can justify such operation and therefore remain eligible for make whole payments.[43]

A primary goal of the capacity performance market design is to assign performance risk to generation owners and to ensure that capacity prices reflect underlying supply and demand conditions, including the cost of

41 *PJM Interconnection, L.L.C. et al.*, 151 FERC ¶ 61,208 at P 437 (June 9th Order).
42 *Id* at P 439.
43 *Id* at P 440.

taking on performance risk. The Order's determination on parameters is not consistent with that goal. By permitting generation owners to establish unit parameters based on nonphysical limits, the June 9th Order has weakened the incentives for units to be flexible and has weakened the assignment of performance risk to generation owners. Contractual limits, unlike generating unit operational limits, are a function of the interests and incentives of the parties to the contracts. If a generation owner expects to be compensated through uplift payments for running for 24 hours regardless of whether the energy is economic or needed, that generation owner has no incentive to pay more to purchase the flexible gas service that would permit the unit to be flexible in response to dispatch.

The fact that a contract may be just and reasonable because it was an arm's length contract entered into by two willing parties does not mean that is the only possible arrangement between the two parties or that it is consistent with an efficient market outcome. The actual contractual terms are a function of the incentives and interests of the parties. The fact that a just and reasonable contract exists between a generation owner and a gas supplier does not mean that it is appropriate or efficient to impose the resultant costs on electric customers or that it incorporates an efficient allocation of performance risk between the generation owner and other market participants.

The approach to parameters defined in the June 9th Order would increase energy market uplift payments substantially. Uplift costs are unpredictable, opaque and unhedgeable. Electric customers are not in a position to determine the terms of the contracts that resources enter into. Customers rely on the market rules to create incentives that protect them by assigning operational risk to generators, who are in the best position to efficiently manage those risks.

The MMU recommends that the revised rules recognize the difference between operational parameters that indicate to PJM dispatchers what a unit is capable of during the operating day and the parameters that are reflected in uplift payments. The parameters provided to PJM dispatchers each day should reflect what units are physically capable of. That is an operational necessity. However, the parameters which determine the amount of uplift payments to those generators should reflect the flexibility goals of the capacity performance construct.

The MMU recommends that resources be held to the OEM operating parameters of the capacity market CONE reference resource for performance assessment and energy uplift payments. This solution creates the incentives for flexibility and preserves, to the extent possible, the incentives to follow PJM's dispatch instructions during tight conditions. The proposed operating parameters should be based on the physical capability of the Reference Resource used in the Cost of New Entry, currently two GE Frame 7FA turbines with dual fuel capability. All resources that are less flexible than the Reference Resource are expected to be scheduled and running during tight conditions anyway, while the flexible CTs that are used as peaking plants would still have the incentive to follow LMP and dispatch instructions. CCs would also have the capability to be as flexible as the reference resource. These units will be exempt from nonperformance charges and made whole as long as they perform in accordance with their parameters. This ensures that all the peaking units that are needed by PJM for flexible operation do not self schedule at their maximum output, and follow PJM dispatch instructions during tight conditions. If any of the less flexible resources need to be dispatched down by PJM for reliability reasons, they would be exempt from nonperformance charges.

Such an approach is consistent with the Commission's no excuses policy for nonperformance because the flexibility target is set based on the optimal OEM-defined capability for the marginal resource that is expected to meet peak demand, which is consistent with the level of performance that customers are paying for in the capacity market. Any resource that is less flexible is not excused for nonperformance and any resource that meets the flexibility target is performing according to the commitments made in the capacity market.

The June 9th Order pointed out that the way to ensure that a resource's parameters are exposed to market consequences is to not allow any parameter limitations as an excuse for nonperformance. The same logic should apply to energy market uplift rules. A resource's parameters should be exposed to market consequences and the resource should not be made whole if it is operating less flexibly than the reference resource. Paying energy market uplift on the basis of parameters consistent with the flexibility goals of the capacity performance construct would ensure that performance incentives are consistent across the capacity and energy markets and ensure that performance risk is appropriately assigned to generation owners.

Markup Index

The markup index is a summary measure of participant offer behavior or conduct for individual marginal units. The markup index for each marginal unit is calculated as (Price – Cost)/Price.[44] The markup index is normalized and can vary from -1.00 when the offer price is less than short run marginal cost, to 1.00 when the offer price is higher than short run marginal cost. The markup index does not measure the impact of unit markup on total LMP.

Real-Time Markup

Table 3-28 shows the average markup index of marginal units in the Real-Time Energy Market, by offer price category using unadjusted cost offers. Table 3-29 shows the average markup index of marginal units in the Real-Time Energy Market, by offer price category using adjusted cost offers. The markup is negative if the cost-based offer of the marginal unit exceeds its price-based offer at its operating point. In the first six months of 2016, 89.4 percent of marginal units had average dollar markups less than zero, when using unadjusted offers. In the first six months of 2016, 89.4 percent of marginal units had average dollar markups less than zero, when using adjusted offers. The data shows that some marginal units did have substantial markups. Among the units that were marginal in the first six months of 2016, none of them had offer prices above $400 per MWh. Among the units that were marginal in the first six months of 2015, 0.30 percent of units had offer prices greater than $400 per MWh with average dollar markup of $56.87 per MWh. Using the unadjusted cost offers, the highest markup in the first six months of 2016 was $258.16 while the highest markup in the first six months of 2015 was $792.21.

44 In order to normalize the index results (i.e., bound the results between +1.00 and -1.00), the index is calculated as (Price – Cost)/Price when price is greater than cost, and (Price – Cost)/Cost when price is less than cost.

Table 3-28 Average, real-time marginal unit markup index (By offer price category unadjusted): January through June, 2015 and 2016

	2015 (Jan-Jun)			2016 (Jan-Jun)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	(0.05)	($2.60)	35.2%	0.02	($0.78)	69.4%
$25 to $50	(0.03)	($1.30)	48.4%	(0.04)	($2.66)	20.0%
$50 to $75	0.06	$3.27	4.0%	0.16	$8.99	1.4%
$75 to $100	0.10	$7.35	1.6%	0.34	$29.69	0.5%
$100 to $125	0.09	$9.02	1.5%	0.05	$5.99	2.1%
$125 to $150	0.06	$6.92	1.4%	0.01	$1.04	4.8%
>= $150	0.05	$12.10	7.9%	0.04	$7.14	1.8%

Table 3-29 Average, real-time marginal unit markup index (By offer price category adjusted): January through June, 2015 and 2016

	2015 (Jan-Jun)			2016 (Jan-Jun)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	(0.01)	($1.53)	35.2%	0.06	$0.11	69.4%
$25 to $50	0.02	$0.31	48.4%	0.01	($0.81)	20.0%
$50 to $75	0.08	$4.41	4.0%	0.18	$9.86	1.4%
$75 to $100	0.10	$7.84	1.6%	0.34	$30.41	0.5%
$100 to $125	0.09	$9.34	1.5%	0.05	$6.00	2.1%
$125 to $150	0.06	$7.20	1.4%	0.01	$1.04	4.8%
>= $150	0.05	$12.29	7.9%	0.04	$7.18	1.8%

Table 3-30 shows the average highest markup of all offered units by the fuel type. Unlike a marginal unit's markup, which was calculated at the specified dispatch point, the highest markup offered by a unit within its economic operating range is included in this measure.

In the first six months of 2016, the average highest markup of a coal unit was $19.90 per MWh. In the first six months of 2015, the average highest markup of a coal unit was $7.74. In the first six months of 2016, the average highest markup of a natural gas unit was $20.33 per MWh. In the first six months of 2015, the average highest markup of a natural gas unit was $25.96 per MWh.

Table 3-30 Average, real-time offered unit markup (By Fuel Price Unadjusted): January through June, 2015 and 2016

	2015 (Jan-Jun)	2016 (Jan-Jun)
Fuel Type	Average Highest Markup	Average Highest Markup
Coal	$7.74	$19.90
Gas	$25.96	$20.33
Municipal Waste	$8.46	$0.29
Oil	$64.94	$38.01
Other	$54.94	$19.04
Uranium	($0.36)	($0.82)
Wind	($3.32)	($2.86)

Day-Ahead Markup

Table 3-31 shows the average markup index of marginal units in the Day-Ahead Energy Market, by offer price category using unadjusted offers. In the first six months of 2016, 62.9 percent of marginal units had average dollar markups less than zero and an average markup index less than or equal to 0.00. The data show that some marginal units in the first six months of 2016 did have substantial markups. The average markup index increased significantly, for example, from 0.11 in the first six months of 2015, to 0.42 in the first six months of 2016 in the offer price category from $50 to $75.

Table 3-31 Average day-ahead marginal unit markup index (By offer price category, unadjusted): January through June, 2015 and 2016

	2015 (Jan - Jun)			2016 (Jan - Jun)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	0.03	($0.67)	34.6%	(0.01)	($0.07)	62.9%
$25 to $50	0.01	$0.33	53.7%	0.19	$5.25	24.8%
$50 to $75	0.11	$6.28	3.3%	0.42	$23.24	1.6%
$75 to $100	0.04	$2.52	1.6%	0.10	$8.24	0.1%
$100 to $125	(0.00)	($2.50)	1.2%	0.03	$3.44	0.6%
$125 to $150	(0.00)	($3.19)	1.2%	0.01	$1.71	7.7%
>= $150	0.02	$4.01	4.0%	0.01	$2.95	1.8%

Table 3-32 shows the average markup index of marginal units in the Day-Ahead Energy Market, by offer price category using adjusted offers. In the first six months of 2016, 0.00 percent of marginal units had average dollar markups less than zero and an average markup index less than or equal to 0.00. The average markup index increased significantly, for example, from 0.13 in the first six months of 2015, to 0.45 in the first six months of 2016 in the offer price category from $50 to $75.

Table 3-32 Average day-ahead marginal unit markup index (By offer price category, adjusted): January through June, 2015 and 2016

	2015 (Jan - Jun)			2016 (Jan - Jun)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	0.07	$0.56	34.6%	0.03	$0.82	62.9%
$25 to $50	0.06	$1.95	53.7%	0.23	$6.62	24.8%
$50 to $75	0.13	$7.51	3.3%	0.45	$24.89	1.6%
$75 to $100	0.04	$2.76	1.6%	0.10	$8.24	0.1%
$100 to $125	0.00	($1.97)	1.2%	0.03	$3.44	0.6%
$125 to $150	0.00	($2.84)	1.2%	0.01	$1.71	7.7%
>= $150	0.03	$4.07	4.0%	0.01	$2.95	1.8%

Frequently Mitigated Units and Associated Units

An FMU is a frequently mitigated unit. The results reported here include units that were mitigated for any reason, including both structural market power in the energy market and units called on for reliability reasons, including reactive and black start service.

The FMU adder was filed with FERC in 2005, and approved effective February 2006.[45] The goal, in 2005, was to ensure that units that were offer capped for most of their run hours could cover their going forward or avoidable costs (also known as ACR in the PJM Capacity Market). That function became unnecessary with the introduction of the RPM capacity market design in 2007, and changes to the scarcity pricing rules in 2012. Under the RPM design, units can make offers in the capacity market that include their ACR net of net revenues. Thus, if there is a shortfall in ACR recovery, that shortfall is included

45 110 FERC ¶ 61,053 (2005).

in the RPM offer. If the unit clears in RPM, it covers its shortfall in ACR costs. If the unit does not clear, then the market result means that PJM can provide reliability without the unit and no additional revenue is needed.

For those reasons, the MMU recommended the elimination of FMU and AU adders.[46] FMU and AU adders no longer serve the purpose for which they were created and interfere with the efficient operation of PJM markets.

The MMU and PJM proposed a compromise on the elimination of FMU adders that maintains the ability of generating units to qualify for FMU adders when units have net revenues less than unit going forward costs or ACR. PJM submitted the joint MMU/PJM proposal to the Commission pursuant to section 206 of the Federal Power Act. On October 31, 2014, the Commission conditionally approved the filing and the new rule became effective November 1, 2014.

The definition of FMUs provides for a set of graduated adders associated with increasing levels of offer capping. Units capped for 60 percent or more of their run hours and less than 70 percent are eligible for an adder of either 10 percent of their cost-based offer or $20 per MWh. Units capped for 70 percent or more of their run hours and less than 80 percent are eligible for an adder of either 10 percent of their cost-based offer or $30 per MWh. Units capped for 80 percent or more of their run hours are eligible for an adder of either 10 percent of their cost-based offer or $40 per MWh. These categories are designated Tier 1, Tier 2 and Tier 3.

In addition to being offer capped for the designated percent of run hours, in order to qualify for an FMU adder, a generating unit's Projected PJM Market Revenues plus the unit's PJM capacity market revenues on a rolling 12-month basis, divided by the unit's MW of installed capacity (in $/MW-year) must be less than its accepted unit specific Avoidable Cost Rate (in $/MW-year) (excluding APIR and ARPIR), or its default Avoidable Cost Rate (in $/MW-year) if no unit-specific Avoidable Cost Rate is accepted for the BRAs for the Delivery Years included in the rolling 12-month period, determined pursuant to Sections 6.7 and 6.8 of Attachment DD of the Tariff. (The relevant Avoidable Cost Rate is the weighted average of the Avoidable Cost Rates for each Delivery Year included in the rolling 12-month period, weighted by month.) No portion of the unit may be included in an FRR capacity plan or be receiving compensation under Part V of the PJM Tariff and the unit must be internal to the PJM Region and subject only to PJM dispatch.[47]

An AU, or associated unit, is a unit that is physically, electrically and economically identical to an FMU, but does not qualify for the same FMU adder based on the number of run-hours the unit is offer capped.[48] For example, if a generating station had two identical units with identical electrical impacts on the system, one of which was offer capped for more than 80 percent of its run hours, that unit would be designated a Tier 3 FMU. If the second unit were capped for 30 percent of its run hours, that unit would be an AU and receive the same Tier 3 adder as the FMU at the site. The AU designation was implemented to ensure that the associated unit is not dispatched in place of the FMU, resulting in no effective adder for the FMU. In the absence of the AU designation, the associated unit would be an FMU after its dispatch and the FMU would be dispatched in its place after losing its FMU designation.

Figure 3-26 shows the total number of FMUs and AUs that qualified for an adder since the inception of the business rule in February 2006. The new rules for determining the qualification of a unit as an FMU or AU became effective November 1, 2014. FMUs and AUs are designated monthly, and a unit's capping percentage is based on a rolling 12-month average, effective with a one-month lag.[49] The number of units that were eligible for an FMU or AU adder declined from an average of 70 units during the first 11 months of 2014, to zero since December 2014.

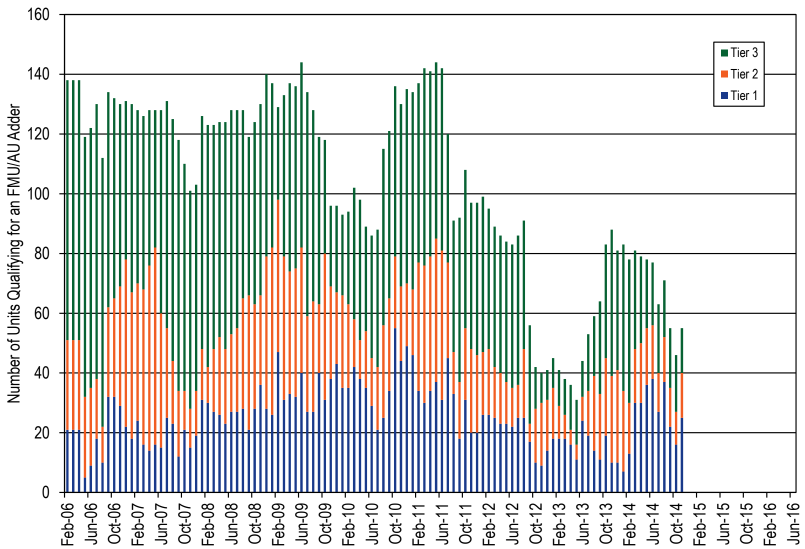
46 See the *"FMU Problem Statement and Issue Charge,"* <http://www.monitoringanalytics.com/reports/Presentations/2013/IMM_MIC_FMU_Problem_Statement_and_Issue_Charge_20130306.pdf>

47 PJM. OA, Schedule 1 § 6.4.2.

48 An associated unit (AU) must belong to the same design class (where a design class includes generation that is the same size and utilizes the same technology, without regard to manufacturer) and uses the identical primary fuel as the FMU.

49 PJM. OA, Schedule 1 § 6.4.2. In 2007, the FERC approved OA revisions to clarify the AU criteria.

Figure 3-26 Frequently mitigated units and associated units (By month): February, 2006 through June, 2016



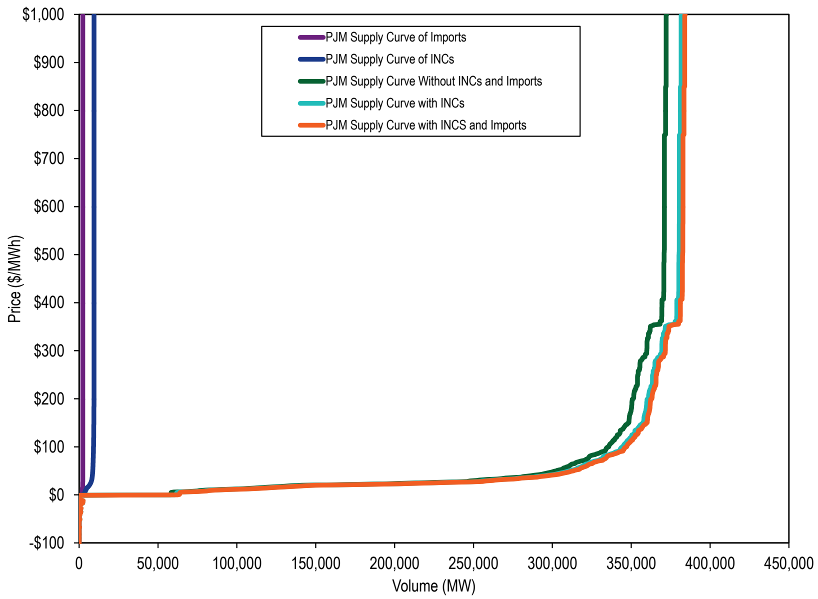
Virtual Offers and Bids

There is a substantial volume of virtual offers and bids in the PJM Day-Ahead Energy Market and such offers and bids may be marginal, based on the way in which the PJM optimization algorithm works.

Any market participant in the PJM Day-Ahead Energy Market can use increment offers, decrement bids, up to congestion transactions, import transactions and export transactions as financial instruments that do not require physical generation or load. Increment offers and decrement bids may be submitted at any hub, transmission zone, aggregate, or single bus for which LMP is calculated. Up to congestion transactions may be submitted between any two buses on a list of 431 buses, eligible for up to congestion transaction bidding.[50] Financial Transaction Rights (FTRs) bids may be submitted at any bus on a list of selected buses that change every planning period, eligible for FTRs. Import and export transactions may be submitted at any interface pricing point, where an import is equivalent to a virtual offer that is injected into PJM and an export is equivalent to a virtual bid that is withdrawn from PJM.

Figure 3-27 shows the PJM day-ahead daily aggregate supply curve of increment offers, the system aggregate supply curve of imports, the system aggregate supply curve without increment offers and imports, the system aggregate supply curve with increment offers, and the system aggregate supply curve with increment offers and imports for an example day in 2016.

Figure 3-27 PJM day-ahead aggregate supply curves: 2016 example day



50 Market participants were required to specify an interface pricing point as the source for imports, an interface pricing point as the sink for exports or an interface pricing point as both the source and sink for transactions wheeling through PJM. On November 1, 2012, PJM eliminated this requirement. For the list of eligible sources and sinks for up to congestion transactions, see www.pjm.com *"OASIS-Source-Sink-Link.xls,"*<http://www.pjm.com/~/media/etools/oasis/references/oasis-source-sink-link.ashx>.

Table 3-33 shows the hourly average number of cleared and submitted increment offers and decrement bids by month for January 2015 through June 2016. The hourly average submitted and cleared increment MW increased by 15.0 and 11.3 percent, from 7,190 MW and 4,713 MW in the first six months of 2015 to 8,268 MW and 5,245 MW in the first six months of 2016. The hourly average submitted decrement MW decreased by 1.7 percent and cleared decrement MW increased by 0.8 percent, from 7,366 MW and 4,300 MW in the first six months of 2015 to 7,239 MW and 4,332 MW in the first six months of 2016.

Table 3-33 Hourly average number of cleared and submitted INCs, DECs by month: January 2015 through June 2016

		Increment Offers				Decrement Bids			
Year		Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
2015	Jan	4,350	6,447	78	398	5,153	7,320	76	295
2015	Feb	4,754	7,109	116	578	4,511	7,445	72	409
2015	Mar	4,973	8,689	142	760	4,305	8,894	101	648
2015	Apr	4,511	6,351	187	558	3,453	6,990	84	451
2015	May	5,089	7,459	181	656	4,171	6,823	94	404
2015	Jun	4,592	7,043	143	697	4,196	6,696	89	410
2015	Jul	4,101	6,534	128	745	3,335	5,830	86	448
2015	Aug	4,457	6,956	135	749	3,433	5,506	74	398
2015	Sep	4,527	6,772	148	733	4,391	7,030	112	437
2015	Oct	4,631	7,112	199	846	3,990	6,757	112	462
2015	Nov	5,022	7,822	223	1,008	3,671	6,435	109	482
2015	Dec	5,102	7,775	189	1,010	4,028	6,869	129	486
2015	Annual	4,675	7,175	156	729	4,051	6,879	95	444
2016	Jan	5,035	8,093	174	1,066	4,286	7,569	100	534
2016	Feb	4,831	8,710	178	1,150	4,259	8,158	113	572
2016	Mar	5,715	8,548	208	1,045	3,690	6,357	101	502
2016	Apr	5,630	8,343	186	964	4,115	7,066	101	509
2016	May	5,113	7,652	161	976	4,321	6,256	103	477
2016	Jun	5,130	8,291	153	1,054	5,344	8,107	128	585
2016	Annual	5,245	8,268	177	1,042	4,332	7,239	108	529

Table 3-34 shows the average hourly number of up to congestion transactions and the average hourly MW for January 2015 through June 2016. In the first six months of 2016, the average hourly up to congestion submitted MW increased 101.9 percent and cleared MW increased 98.7 percent, compared to the first six months of 2015, as a result of the expiration of the fifteen month potential refund period for the proceeding related to uplift charges for UTC transactions in December 2015. Section 206(b) of the Federal Power Act states that "…the Commission may order refunds of any amounts paid, for the period subsequent to the refund effective date through a date fifteen months after such refund effective date…"[51]

Table 3-34 Hourly average of cleared and submitted up to congestion bids by month: January 2015 through June 2016

		Up to Congestion			
Year		Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
2015	Jan	15,903	46,626	806	2,132
2015	Feb	17,255	57,318	892	2,695
2015	Mar	18,382	72,906	978	2,909
2015	Apr	16,300	73,446	811	2,734
2015	May	18,929	81,358	941	3,219
2015	Jun	17,714	81,452	896	3,220
2015	Jul	18,883	88,543	952	3,502
2015	Aug	18,490	102,084	1,126	4,291
2015	Sep	20,779	108,730	1,451	4,909
2015	Oct	20,183	100,673	1,493	4,736
2015	Nov	20,880	86,857	1,468	4,067
2015	Dec	27,124	99,083	1,933	4,841
2015	Annual	19,255	83,422	1,147	3,611
2016	Jan	39,446	135,369	2,455	6,015
2016	Feb	38,818	152,891	2,091	5,748
2016	Mar	31,938	147,963	1,704	5,094
2016	Apr	29,212	128,349	2,689	6,079
2016	May	32,883	120,132	2,977	6,006
2016	Jun	35,469	151,414	2,528	6,406
2016	Annual	34,607	139,199	2,409	5,889

Table 3-35 shows the average hourly number of import and export transactions and the average hourly MW for January 2015 through June 2016. In the first six months of 2016, the average hourly submitted and cleared import transaction MW decreased by 40.2 and 34.7 percent, and the average hourly

51 16 U.S.C. § 824e.

submitted and cleared export transaction MW decreased 16.2 and 15.7 percent, compared to the first six months of 2015.

Table 3-35 Hourly average number of cleared and submitted import and export transactions by month: January 2015 through June 2016

		Imports				Exports			
Year		Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
2015	Jan	2,579	4,559	26	26	4,473	4,559	26	26
2015	Feb	4,383	4,469	23	25	4,383	4,469	23	25
2015	Mar	3,268	3,302	16	17	3,268	3,302	16	17
2015	Apr	2,624	2,626	13	13	2,624	2,626	13	13
2015	May	2,612	2,623	17	17	2,612	2,623	17	17
2015	Jun	2,895	2,906	14	14	2,895	2,906	14	14
2015	Jul	2,961	2,983	14	14	2,961	2,983	14	14
2015	Aug	3,209	3,239	15	15	3,209	3,239	15	15
2015	Sep	3,873	3,913	18	18	3,873	3,913	18	18
2015	Oct	2,190	2,197	11	11	2,190	2,197	11	11
2015	Nov	2,715	2,734	15	15	2,715	2,734	15	15
2015	Dec	2,475	2,483	13	13	2,475	2,483	13	13
2015	Annual	3,131	3,160	16	17	3,131	3,160	16	17
2016	Jan	2,059	2,103	15	16	2,564	2,571	13	14
2016	Feb	2,396	2,480	20	22	2,634	2,653	13	13
2016	Mar	2,097	2,145	17	18	2,324	2,330	11	11
2016	Apr	2,150	2,180	16	16	2,620	2,635	13	13
2016	May	1,889	1,947	12	14	2,484	2,492	14	15
2016	Jun	1,335	1,366	6	7	4,428	4,471	23	24
2016	Annual	1,986	2,035	14	15	2,837	2,853	15	15

Table 3-36 shows the frequency with which generation offers, import or export transactions, up to congestion transactions, decrement bids, increment offers and price-sensitive demand are marginal for the first six months of 2015 and 2016.

Figure 3-28 shows the monthly volume of bid and cleared INC, DEC and up to congestion bids by month for the period from January 2005 through June 2016.

Table 3-36 Type of day-ahead marginal units: January through June, 2015 and 2016

	2015						2016				
	Generation	Dispatchable Transaction	Up to Congestion Transaction	Decrement Bid	Increment Offer	Price Sensitive Demand	Generation	Dispatchable Transaction	Up to Congestion Transaction	Decrement Bid	Increment Offer
Jan	14.2%	0.5%	71.9%	6.9%	6.3%	0.1%	5.3%	0.1%	85.2%	5.6%	3.8%
Feb	13.1%	0.4%	73.1%	7.6%	5.6%	0.1%	5.5%	0.0%	83.5%	7.4%	3.6%
Mar	10.0%	0.7%	73.3%	10.6%	5.3%	0.0%	7.0%	0.1%	80.6%	7.7%	4.7%
Apr	10.4%	0.3%	73.2%	10.8%	5.3%	0.0%	5.8%	0.0%	82.3%	8.1%	3.7%
May	10.2%	0.1%	75.2%	9.2%	5.3%	0.0%	6.2%	0.1%	83.8%	6.5%	3.4%
Jun	8.0%	0.1%	78.2%	9.5%	4.1%	0.0%	3.5%	0.0%	84.2%	8.5%	3.7%
Annual	11.0%	0.4%	74.1%	9.1%	5.4%	0.0%	5.5%	0.1%	83.3%	7.3%	3.8%

Figure 3-28 Monthly bid and cleared INCs, DECs and UTCs (MW): January 2005 through June 2016

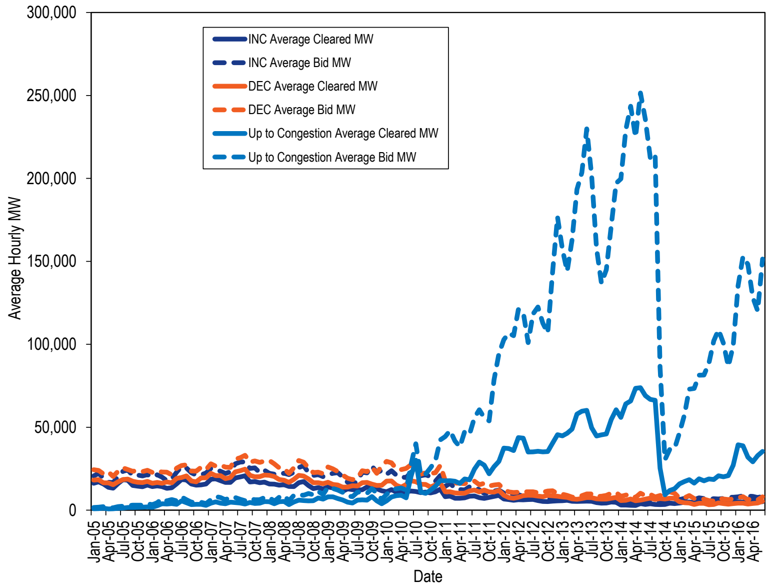


Figure 3-29 Daily bid and cleared INCs, DECs, and UTCs (MW): 2015 through June 2016

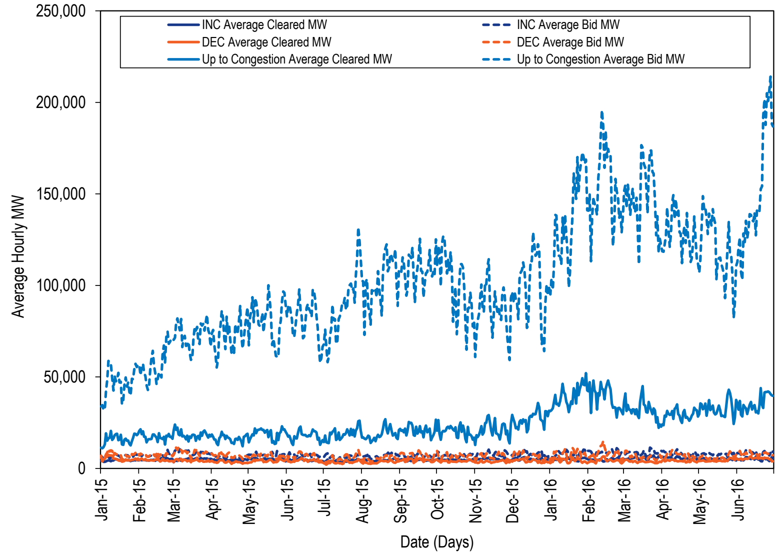


Figure 3-29 shows the daily volume of bid and cleared INC, DEC and up to congestion bids for the period from January 2015 through June 2016.

In order to evaluate the ownership of virtual bids, the MMU categorizes all participants making virtual bids in PJM as either physical or financial. Physical entities include utilities and customers which primarily take physical positions in PJM markets. Financial entities include banks and hedge funds which primarily take financial positions in PJM markets. International market participants that primarily take financial positions in PJM markets are generally considered to be financial entities even if they are utilities in their own countries.

Table 3-37 shows, for the first six months of 2015 and 2016, the total increment offers and decrement bids and cleared MW by whether the parent organization is financial or physical.

Table 3-37 PJM INC and DEC bids and cleared MW by type of parent organization (MW): January through June, 2015 and 2016

	Jan-Jun 2015				Jan-Jun 2016			
Category	Total Virtual Bid MW	Percent	Total Virtual Cleared MW	Percent	Total Virtual Bid MW	Percent	Total Virtual Cleared MW	Percent
Financial	26,667,613	42.2%	7,753,951	19.9%	34,784,319	51.4%	13,696,238	32.7%
Physical	36,544,243	57.8%	31,227,205	80.1%	32,930,167	48.6%	28,128,133	67.3%
Total	63,211,856	100.0%	38,981,156	100.0%	67,714,486	100.0%	41,824,370	100.0%

Table 3-38 shows, for the first six months of 2015 and 2016, the total up to congestion bids and cleared MW by whether the parent organization is financial or physical.

Table 3-38 PJM up to congestion transactions by type of parent organization (MW): January through June, 2015 and 2016

	Jan-Jun 2015				Jan-Jun 2016			
Category	Total Up to Congestion Bid MW	Percent	Total Up to Congestion Cleared MW	Percent	Total Up to Congestion Bid MW	Percent	Total Up to Congestion Cleared MW	Percent
Financial	273,823,300	91.4%	62,602,499	82.7%	574,350,507	94.5%	138,496,938	91.6%
Physical	25,682,155	8.6%	13,073,994	17.3%	33,543,256	5.5%	12,661,343	8.4%
Total	299,505,455	100.0%	75,676,494	100.0%	607,893,763	100.0%	151,158,281	100.0%

Table 3-39 shows for the first six months of 2015 and 2016, the total import and export transactions by whether the parent organization is financial or physical.

Table 3-39 PJM import and export transactions by type of parent organization (MW): January through June, 2015 and 2016

	Jan-Jun 2015		Jan-Jun 2016	
Category	Total Import and Export MW	Percent	Total Import and Export MW	Percent
Financial	10,531,899	40.4%	8,544,178	37.8%
Physical	15,561,730	59.6%	14,084,557	62.2%
Total	26,093,629	100.0%	22,628,735	100.0%

Table 3-40 shows increment offers and decrement bids bid by top ten locations for the first six months of 2015 and 2016.

Table 3-40 PJM virtual offers and bids by top ten locations (MW): January through June, 2015 and 2016

Jan-Jun 2015					Jan-Jun 2016				
Aggregate/Bus Name	Aggregate/ Bus Type	INC MW	DEC MW	Total MW	Aggregate/Bus Name	Aggregate/ Bus Type	INC MW	DEC MW	Total MW
WESTERN HUB	HUB	9,644,293	11,368,368	21,012,662	WESTERN HUB	HUB	11,344,223	10,738,691	22,082,914
SOUTHIMP	INTERFACE	4,116,718	0	4,116,718	SOUTHIMP	INTERFACE	2,581,862	0	2,581,862
IMO	INTERFACE	2,553,011	36,819	2,589,830	N ILLINOIS HUB	HUB	571,541	1,104,654	1,676,195
N ILLINOIS HUB	HUB	446,003	1,625,506	2,071,509	MISO	INTERFACE	222,980	1,439,780	1,662,760
NYIS	INTERFACE	1,036,204	201,609	1,237,813	NYIS	INTERFACE	847,338	583,312	1,430,650
LINDENVFT	INTERFACE	200,100	560,299	760,399	BGE	ZONE	255,618	1,127,731	1,383,348
MISO	INTERFACE	225,653	484,675	710,328	AEP-DAYTON HUB	HUB	678,070	360,689	1,038,759
BGE	ZONE	81,842	578,517	660,359	PEPCO	ZONE	255,807	406,009	661,816
BOCGASE2138 KV T1	LOAD	113,791	526,349	640,140	IMO	INTERFACE	608,336	2,397	610,733
AEP-DAYTON HUB	HUB	260,402	360,024	620,427	PECO	ZONE	477,733	105,529	583,262
Top ten total		18,678,019	15,742,166	34,420,185			17,843,507	15,868,790	33,712,297
PJM total		31,169,922	31,964,981	63,134,903			36,107,139	31,613,123	67,720,262
Top ten total as percent of PJM total		59.9%	49.2%	54.5%			49.4%	50.2%	49.8%

Table 3-41 shows up to congestion transactions by import bids for the top ten locations for the first six months of 2015 and 2016.[52]

52 The source and sink aggregates in these tables refer to the name and location of a bus and do not include information about the behavior of any individual market participant.

Table 3-41 PJM cleared up to congestion import bids by top ten source and sink pairs (MW): January through June, 2015 and 2016

Jan-Jun 2015				
Imports				
Source	Source Type	Sink	Sink Type	MW
SOUTHIMP	INTERFACE	NAGELAEP	EHVAGG	1,380,592
OVEC	INTERFACE	AEP-DAYTON HUB	HUB	327,713
SOUTHIMP	INTERFACE	WOLF HILLS 1-5	AGGREGATE	303,812
SOUTHEAST	INTERFACE	HALIFXDP TX1	AGGREGATE	243,761
NORTHWEST	INTERFACE	N ILLINOIS HUB	HUB	232,246
NORTHWEST	INTERFACE	COMED	ZONE	214,222
SOUTHEAST	INTERFACE	NAGELAEP	EHVAGG	207,520
SOUTHWEST	INTERFACE	NAGELAEP	EHVAGG	189,037
MISO	INTERFACE	21 KINCA ATR24304	AGGREGATE	188,052
SOUTHEAST	INTERFACE	DOM	ZONE	154,826
Top ten total				3,441,780
PJM total				10,751,372
Top ten total as percent of PJM total				32.0%
Jan-Jun 2016				
Imports				
Source	Source Type	Sink	Sink Type	MW
HUDSONTP	INTERFACE	LEONIA 230 T-2	AGGREGATE	366,487
MISO	INTERFACE	COOK	EHVAGG	340,774
NEPTUNE	INTERFACE	SOUTHRIV 230	AGGREGATE	309,611
SOUTHWEST	INTERFACE	DUMONT	EHVAGG	306,355
OVEC	INTERFACE	COOK	EHVAGG	276,877
NIPSCO	INTERFACE	DUMONT	EHVAGG	248,920
OVEC	INTERFACE	CONESVILLE 5	AGGREGATE	246,745
OVEC	INTERFACE	CABOT	EHVAGG	224,582
MISO	INTERFACE	112 WILTON	EHVAGG	207,638
SOUTHWEST	INTERFACE	COOK	EHVAGG	204,254
Top ten total				2,732,244
PJM total				14,773,440
Top ten total as percent of PJM total				18.5%

Table 3-42 shows up to congestion transactions by export bids for the top ten locations for the first six months of 2015 and 2016.

Table 3-42 PJM cleared up to congestion export bids by top ten source and sink pairs (MW): January through June, 2015 and 2016

Jan-Jun 2015				
Exports				
Source	Source Type	Sink	Sink Type	MW
FOWLER RIDGE II WF	AGGREGATE	SOUTHWEST	INTERFACE	222,312
ROCKPORT	EHVAGG	SOUTHWEST	INTERFACE	139,271
21 KINCA ATR24304	AGGREGATE	NIPSCO	INTERFACE	102,734
COMED	ZONE	NIPSCO	INTERFACE	95,445
MARION	AGGREGATE	HUDSONTP	INTERFACE	85,622
SULLIVAN-AEP	EHVAGG	OVEC	INTERFACE	83,097
FOWLER RIDGE II WF	AGGREGATE	OVEC	INTERFACE	78,238
KAMMER 2	AGGREGATE	NIPSCO	INTERFACE	75,128
ROCKPORT	EHVAGG	OVEC	INTERFACE	70,132
RECO	ZONE	HUDSONTP	INTERFACE	68,907
Top ten total				1,020,885
PJM total				3,967,356
Top ten total as percent of PJM total				25.7%
Jan-Jun 2016				
Exports				
Source	Source Type	Sink	Sink Type	MW
COMED	ZONE	NIPSCO	INTERFACE	692,806
SULLIVAN-AEP	EHVAGG	OVEC	INTERFACE	539,698
21 KINCA ATR24304	AGGREGATE	NIPSCO	INTERFACE	498,037
21 KINCA ATR24404	AGGREGATE	SOUTHWEST	INTERFACE	338,505
21 KINCA ATR24304	AGGREGATE	SOUTHWEST	INTERFACE	325,965
EAST BEND 2	AGGREGATE	SOUTHWEST	INTERFACE	244,826
GRAND RIDGE WF	AGGREGATE	NIPSCO	INTERFACE	220,924
CLOVERDALE	EHVAGG	SOUTHEXP	INTERFACE	206,033
NAGELAEP	EHVAGG	SOUTHEXP	INTERFACE	203,856
STMARYSGEN	AGGREGATE	NIPSCO	INTERFACE	202,965
Top ten total				3,473,616
PJM total				11,052,092
Top ten total as percent of PJM total				31.4%

Table 3-43 shows up to congestion transactions by wheel bids for the top ten locations for the first six months of 2015 and 2016.

Table 3-43 PJM cleared up to congestion wheel bids by top ten source and sink pairs (MW): January through June, 2015 and 2016

Source	Source Type	Sink	Sink Type	MW
Jan-Jun 2015				
Wheels				
Source	Source Type	Sink	Sink Type	MW
MISO	INTERFACE	NORTHWEST	INTERFACE	164,983
MISO	INTERFACE	NIPSCO	INTERFACE	102,566
NORTHWEST	INTERFACE	MISO	INTERFACE	97,460
IMO	INTERFACE	NYIS	INTERFACE	66,458
NYIS	INTERFACE	IMO	INTERFACE	49,286
SOUTHWEST	INTERFACE	IMO	INTERFACE	32,526
SOUTHWEST	INTERFACE	SOUTHEXP	INTERFACE	28,262
NIPSCO	INTERFACE	IMO	INTERFACE	25,972
SOUTHEAST	INTERFACE	SOUTHEXP	INTERFACE	17,399
NYIS	INTERFACE	HUDSONTP	INTERFACE	13,525
Top ten total				598,438
PJM total				711,420
Top ten total as percent of PJM total				84.1%
Jan-Jun 2016				
Wheels				
Source	Source Type	Sink	Sink Type	MW
NORTHWEST	INTERFACE	MISO	INTERFACE	228,710
MISO	INTERFACE	NIPSCO	INTERFACE	212,775
NYIS	INTERFACE	IMO	INTERFACE	199,662
SOUTHWEST	INTERFACE	SOUTHEXP	INTERFACE	127,399
MISO	INTERFACE	NORTHWEST	INTERFACE	116,012
IMO	INTERFACE	NYIS	INTERFACE	99,453
SOUTHWEST	INTERFACE	NIPSCO	INTERFACE	59,197
IMO	INTERFACE	MISO	INTERFACE	42,405
NEPTUNE	INTERFACE	NYIS	INTERFACE	31,556
MISO	INTERFACE	SOUTHEXP	INTERFACE	29,966
Top ten total				1,147,135
PJM total				1,311,291
Top ten total as percent of PJM total				87.5%

On November 1, 2012, PJM eliminated the requirement for market participants to specify an interface pricing point as either the source or sink of an up to congestion transaction. The top ten internal up to congestion transaction locations were 6.0 percent of the PJM total internal up to congestion transactions in the first six months of 2016.

Table 3-44 shows up to congestion transactions by internal bids for the top ten locations for the first six months of 2015 and 2016.

Table 3-44 PJM cleared up to congestion internal bids by top ten source and sink pairs (MW): January through June, 2015 and 2016

Source	Source Type	Sink	Sink Type	MW
Jan-Jun 2015				
Internal				
Source	Source Type	Sink	Sink Type	MW
BERGEN 2CC	AGGREGATE	LEONIA 230 T-1	AGGREGATE	1,290,717
BYRON 1	AGGREGATE	ROCKFORD	AGGREGATE	850,874
JEFFERSON	EHVAGG	COOK	EHVAGG	782,156
ROCKPORT	EHVAGG	JEFFERSON	EHVAGG	681,127
ATSI GEN HUB	HUB	ATSI	ZONE	600,494
VALLEY	EHVAGG	DOOMS	EHVAGG	475,999
RONCO	EHVAGG	HATFIELD	EHVAGG	470,056
BERGEN 2CC	AGGREGATE	LEONIA 230 T-2	AGGREGATE	453,816
167 PLANO	EHVAGG	112 WILTON	EHVAGG	428,844
ALBURTIS	EHVAGG	PPL	ZONE	418,148
Top ten total				6,452,231
PJM total				60,246,346
Top ten total as percent of PJM total				10.7%
Jan-Jun 2016				
Internal				
Source	Source Type	Sink	Sink Type	MW
21 KINCA ATR24404	AGGREGATE	MICHFE	AGGREGATE	921,085
BERGEN 2CC	AGGREGATE	LEONIA 230 T-1	AGGREGATE	860,351
21 KINCA ATR24304	AGGREGATE	MICHFE	AGGREGATE	779,519
112 WILTON	EHVAGG	DUMONT	EHVAGG	742,469
BYRON 1	AGGREGATE	ROCKFORD	AGGREGATE	672,241
ROCKPORT	EHVAGG	JEFFERSON	EHVAGG	601,522
WHIPPANY BK 7	AGGREGATE	TRAYNOR	AGGREGATE	532,314
CLOVERDALE	EHVAGG	CLOVERD2 138 KV T4	AGGREGATE	528,634
BLACKOAK	EHVAGG	BEDINGTON	EHVAGG	528,608
MOUNTAINEER	EHVAGG	COOK	EHVAGG	500,895
Top ten total				6,667,638
PJM total				124,025,599
Top ten total as percent of PJM total				5.4%

Table 3-45 shows the number of source-sink pairs that were offered and cleared monthly in January 2013 through June 2016. The annual row in Table 3-45 is the average hourly number of offered and cleared source-sink pairs for the year for the average columns and the maximum hourly number of offered and cleared source-sink pairs for the year for the maximum columns. The increase in average offered and cleared source-sink pairs beginning in January 2013 and continuing through the first eight months of 2014 illustrates that PJM's modification of the rules governing the location of up to congestion transactions bids resulted in a significant increase in the number of offered and cleared up to congestion transactions. The subsequent reduction in up to congestion transactions (UTC) that followed a FERC order setting September 8, 2014, as the effective date for any uplift charges subsequently assigned to UTCs, was reversed. There was an increase in up to congestion volume as a result of the expiration of the fifteen month refund period for the proceeding related to uplift charges for UTC transactions on December 7, 2015.[53]

Table 3-45 Number of PJM offered and cleared source and sink pairs: January 2013 through June 2016

		Daily Number of Source-Sink Pairs			
Year	Month	Average Offered	Max Offered	Average Cleared	Max Cleared
2013	Jan	6,580	10,548	3,291	5,060
2013	Feb	4,891	7,415	2,755	3,907
2013	Mar	4,858	7,446	2,868	4,262
2013	Apr	6,426	9,064	3,464	4,827
2013	May	5,729	7,914	3,350	4,495
2013	Jun	6,014	8,437	3,490	4,775
2013	Jul	5,955	9,006	3,242	4,938
2013	Aug	6,215	9,751	3,642	5,117
2013	Sep	3,496	4,222	2,510	3,082
2013	Oct	4,743	7,134	3,235	4,721
2013	Nov	8,605	14,065	5,419	8,069
2013	Dec	8,346	11,728	6,107	7,415
2013	Annual	5,996	14,065	3,620	8,069
2014	Jan	7,977	11,191	5,179	7,714
2014	Feb	10,087	11,688	7,173	8,463
2014	Mar	11,360	14,745	7,284	9,943
2014	Apr	11,487	14,106	8,589	10,253
2014	May	11,215	13,477	7,734	9,532
2014	Jun	10,613	14,112	7,374	10,143
2014	Jul	10,057	12,304	7,202	8,486
2014	Aug	10,877	12,863	7,609	9,254
2014	Sep	5,618	11,269	4,281	8,743
2014	Oct	2,871	4,092	1,972	2,506
2014	Nov	2,463	3,988	1,812	3,163
2014	Dec	2,803	3,672	2,197	2,786
2014	Annual	8,109	10,614	5,690	7,570
2015	Jan	3,337	5,422	2,263	3,270
2015	Feb	4,600	7,041	2,775	4,147
2015	Mar	4,061	5,799	2,625	3,244
2015	Apr	3,777	6,967	2,343	3,378
2015	May	4,025	5,513	2,587	3,587
2015	Jun	3,852	5,967	2,781	3,748
2015	Jul	3,957	5,225	2,786	4,044
2015	Aug	4,996	6,143	3,702	4,378
2015	Sep	5,775	7,439	4,222	5,462
2015	Oct	6,000	7,414	4,221	5,397
2015	Nov	5,846	7,148	4,494	5,842
2015	Dec	7,097	8,250	5,709	6,610
2015	Annual	4,259	6,152	2,897	3,912
2016	Jan	7,714	8,793	6,174	7,374
2016	Feb	9,200	11,172	7,203	7,957
2016	Mar	8,826	11,572	6,338	8,126
2016	Apr	7,697	8,473	5,958	6,767
2016	May	8,521	9,398	6,707	7,273
2016	Jun	9,261	10,948	6,913	7,770
2016	Annual	8,536	10,059	6,549	7,545

53 See 148 FERC ¶ 61,144 (2014).

Table 3-46 and Figure 3-30 show total cleared up to congestion transactions by type for the first six months of 2015 and 2016. Internal up to congestion transactions in the first six months of 2016 were 82.0 percent of all up to congestion transactions compared to 79.6 percent in the first six months of 2015.

Table 3-46 PJM cleared up to congestion transactions by type (MW): January through June, 2015 and 2016

	Jan-Jun 2015				
	Cleared Up to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	3,441,780	1,020,885	598,438	6,452,231	11,513,334
PJM total (MW)	10,751,372	3,967,356	711,420	60,246,346	75,676,494
Top ten total as percent of PJM total	32.0%	25.7%	84.1%	10.7%	15.2%
PJM total as percent of all up-to congestion transactions	14.2%	5.2%	0.9%	79.6%	100.0%
	Jan-Jun 2016				
	Cleared Up to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	2,732,244	3,473,616	1,147,135	6,667,638	14,020,633
PJM total (MW)	14,773,440	11,052,092	1,311,291	124,025,599	151,162,422
Top ten total as percent of PJM total	18.5%	31.4%	87.5%	5.4%	9.3%
PJM total as percent of all up-to congestion transactions	9.8%	7.3%	0.9%	82.0%	100.0%

Figure 3-30 shows the initial increase and continued increase in internal up to congestion transactions by month following the November 1, 2012 rule change permitting such transactions, until September 8, 2014. The reduction in up to congestion transactions (UTC) that followed a FERC order setting September 8, 2014, as the effective date for any uplift charges subsequently assigned to UTCs, was reversed. There was an increase in up to congestion volume as a result of the expiration of the fifteen month refund period for the proceeding related to uplift charges for UTC transactions.[54]

Figure 3-30 PJM monthly cleared up to congestion transactions by type (MW): January 2005 through June 2016

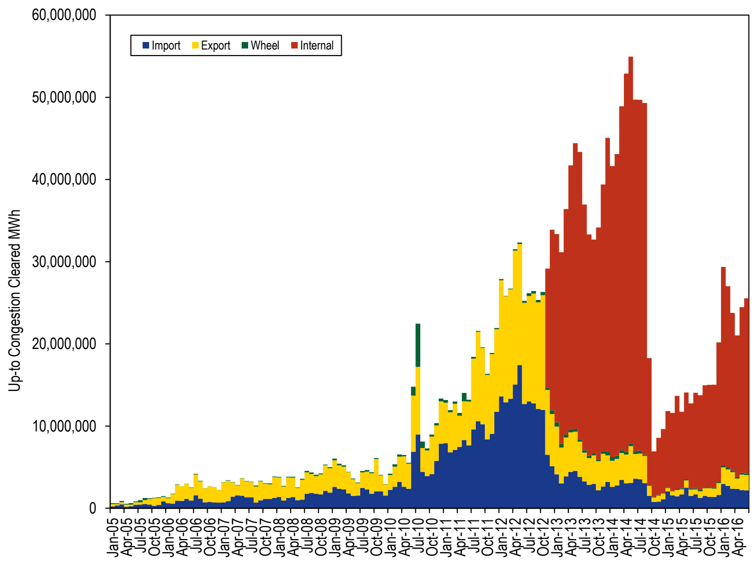
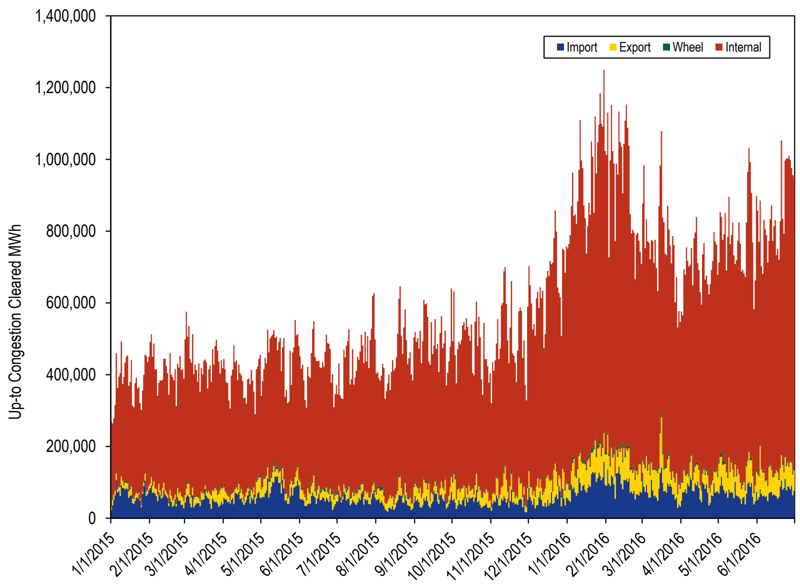


Figure 3-31 shows the daily cleared up to congestion MW by transaction type for the period from January 2015 through June 2016.

54 See 148 FERC ¶ 61,144 (2014).

Figure 3-31 PJM daily cleared up to congestion transaction by type (MW): January 2015 through June 2016



Generator Offers

Generator offers are categorized as dispatchable (Table 3-47) or self scheduled (Table 3-48).[55] Units which are available for economic dispatch are dispatchable. Units which are self scheduled to generate fixed output are self scheduled and must run. Units which are self scheduled at their economic minimum and are available for economic dispatch up to their economic maximum are self scheduled and dispatchable. Table 3-47 and Table 3-48 do not include units that did not indicate their offer status and units that were offered as available to run only during emergency events. The MW offered beyond the economic range of a unit are categorized as emergency MW. The emergency MW are included in both tables.

Table 3-47 shows the proportion of MW offers by dispatchable units, by unit type and by offer price range, for the first six months of 2016. For example, 77.1 percent of CC offers were dispatchable and in the $0 to $200 per MWh price range. The total column is the proportion of all MW offers by unit type that were dispatchable. For example, 84.7 percent of all CC MW offers were dispatchable, including the 7.0 percent of emergency MW offered by CC units. The all dispatchable offers row is the proportion of MW that were offered as available for economic dispatch within a given range by all unit types. For example, 48.5 percent of all dispatchable offers were in the $0 to $200 per MWh price range. The total column in the all dispatchable offers row is the proportion of all MW offers that were offered as available for economic dispatch, including emergency MW. Among all the generator offers in the first six months of 2016, 52.5 percent were offered as available for economic dispatch.

Table 3-47 Distribution of MW for dispatchable unit offer prices: January through June, 2016

	Dispatchable (Range)							
Unit Type	($200) – $0	$0 – $200	$200 – $400	$400 – $600	$600 – $800	$800 – $1,000	Emergency	Total
CC	0.0%	77.1%	0.3%	0.2%	0.0%	0.0%	7.0%	84.7%
CT	0.0%	82.0%	4.4%	0.5%	0.5%	0.0%	11.0%	98.4%
Diesel	3.0%	31.7%	16.6%	5.4%	0.0%	0.0%	17.7%	74.5%
Fuel Cell	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Nuclear	0.0%	6.1%	0.0%	0.0%	0.0%	0.0%	0.1%	6.2%
Pumped Storage	63.9%	0.1%	0.0%	0.0%	0.0%	0.0%	2.2%	66.3%
Run of River	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%
Solar	34.0%	5.8%	0.0%	0.0%	0.0%	0.0%	1.8%	41.6%
Steam	0.1%	47.6%	0.7%	0.0%	0.0%	0.2%	2.8%	51.4%
Transaction	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Wind	50.3%	10.2%	0.0%	0.0%	0.0%	0.0%	0.5%	61.1%
All Dispatchable Offers	2.5%	48.5%	1.2%	0.2%	0.1%	0.1%	4.5%	57.1%

55 Each range in the tables is greater than or equal to the lower value and less than the higher value. The unit type battery is not included in these tables because batteries do not make energy offers. The unit type fuel cell is not included in these tables because of the small number owners and the small number of units of this type of generation.

Table 3-48 shows the proportion of MW offers by unit type that were self scheduled to generate fixed output and by unit type and price range for self-scheduled and dispatchable units, for the first six months of 2016. For example, 9.9 percent of CC offers were self scheduled and dispatchable and in the $0 to $200 price range. The total column is the proportion of all MW offers by unit type that were self scheduled to generate fixed output and are self scheduled and dispatchable. For example, 15.3 percent of all CC MW offers were either self scheduled to generate at fixed output or self scheduled to generate at economic minimum and dispatchable up to economic maximum, including the 1.1 percent of emergency MW offered by CC units. The all self scheduled offers row is the proportion of MW that were offered as either self scheduled to generate at fixed output or self scheduled to generate at economic minimum and dispatchable up to economic maximum within a given range by all unit types. For example, units that were self scheduled to generate at fixed output accounted for 22.0 percent of all offers and self scheduled and dispatchable units accounted for 17.9 percent of all offers. The total column in the all self scheduled offers row is the proportion of all MW offers that were either self scheduled to generate at fixed output or self scheduled to generate at economic minimum and dispatchable up to economic maximum, including emergency MW. Among all the generator offers in the first six months of 2016, 23.6 percent were offered as self scheduled and 19.4 percent were offered as self scheduled and dispatchable.

Table 3-48 Distribution of MW for self scheduled offer prices: January through June, 2016

	Self Scheduled		Self Scheduled and Dispatchable (Range)							
Unit Type	Must Run	Emergency	($200) - $0	$0 - $200	$200 - $400	$400 - $600	$600 - $800	$800 - $1,000	Emergency	Total
CC	3.0%	1.1%	0.4%	9.9%	0.0%	0.0%	0.0%	0.0%	0.9%	15.3%
CT	0.7%	0.1%	0.0%	0.7%	0.1%	0.0%	0.0%	0.0%	0.0%	1.6%
Diesel	19.3%	1.0%	2.2%	1.6%	0.0%	0.0%	0.0%	0.0%	1.3%	25.5%
Fuel Cell	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Nuclear	88.7%	1.1%	3.1%	0.9%	0.0%	0.0%	0.0%	0.0%	0.1%	93.8%
Pumped Storage	17.9%	9.2%	2.8%	0.0%	0.0%	0.0%	0.0%	0.0%	3.8%	33.7%
Run of River	60.0%	13.3%	0.2%	19.6%	0.0%	0.0%	0.0%	0.7%	6.0%	99.8%
Solar	41.9%	15.0%	1.4%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	58.4%
Steam	4.9%	1.7%	0.2%	38.8%	0.0%	0.0%	0.0%	0.0%	2.9%	48.6%
Transaction	76.2%	23.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Wind	4.6%	3.9%	23.4%	3.2%	0.0%	0.0%	0.0%	0.0%	3.7%	38.9%
All Self-Scheduled Offers	22.0%	1.6%	1.2%	16.6%	0.0%	0.0%	0.0%	0.0%	1.5%	42.9%

Market Performance

The PJM average locational marginal price (LMP) reflects the configuration of the entire RTO. The PJM Energy Market includes the Real-Time Energy Market and the Day-Ahead Energy Market.

Markup

The markup index, which is a measure of participant conduct for individual marginal units, does not measure the impact of participant behavior on market prices. As an example, if unit A has a $90 cost and a $100 price, while unit B has a $9 cost and a $10 price, both would show a markup of 10 percent, but the price impact of unit A's markup at the generator bus would be $10 while the price impact of unit B's markup at the generator bus would be $1. Depending on each unit's location on the transmission system, those bus-level impacts could also translate to different impacts on total system price.

The MMU calculates the impact on system prices of marginal unit price-cost markup, based on analysis using sensitivity factors. The calculation shows the markup component of price-based on a comparison between the price-based offer and the cost-based offer of each actual marginal unit on the system.[56]

56 This is the same method used to calculate the fuel cost adjusted LMP and the components of LMP.

The price impact of markup must be interpreted carefully. The markup calculation is not based on a full redispatch of the system to determine the marginal units and their marginal costs that would have occurred if all units had made all offers at short run marginal cost. Thus the results do not reflect a counterfactual market outcome based on the assumption that all units made all offers at short run marginal cost. It is important to note that a full redispatch analysis is practically impossible and a limited redispatch analysis would not be dispositive. Nonetheless, such a hypothetical counterfactual analysis would reveal the extent to which the actual system dispatch is less than competitive if it showed a difference between dispatch based on short run marginal cost and actual dispatch. It is possible that the unit-specific markup, based on a redispatch analysis, would be lower than the markup component of price if the reference point were an inframarginal unit with a lower price and a higher cost than the actual marginal unit. If the actual marginal unit has short run marginal costs that would cause it to be inframarginal, a new unit would be marginal. If the offer of that new unit were greater than the cost of the original marginal unit, the markup impact would be lower than the MMU measure. If the newly marginal unit is on a price-based schedule, the analysis would have to capture the markup impact of that unit as well.

The MMU calculated an explicit measure of the impact of marginal unit markups on LMP. The markup impact includes the impact of the identified markup conduct on a unit by unit basis, but the inclusion of negative markup impacts has an offsetting effect. The markup analysis does not distinguish between intervals in which a unit has local market power or has a price impact in an unconstrained interval. The markup analysis is a more general measure of the competitiveness of the energy market.

Real-Time Markup

Markup Component of Real-Time Price by Fuel, Unit Type

The markup component of price is the difference between the system price, when the system price is determined by the active offers of the marginal units, whether price or cost-based, and the system price, based on the cost-based offers of those marginal units.

Table 3-49 shows the average unit markup component of LMP for marginal units, by unit type and primary fuel. The markup component of LMP is a measure of the impact of the markups of marginal units shown in Table 3-49 on the system-wide load-weighted LMP. The negative markup components of LMP reflect the negative markups shown in the Table 3-28.

All generating units, including coal units, are allowed to include a 10 percent adder in their cost offer. The 10 percent adder was included in the definition of cost offers prior to the implementation of PJM markets in 1999, based on the uncertainty of calculating the hourly operating costs of CTs under changing ambient conditions. Coal units do not face the same cost uncertainty as gas-fired CTs. A review of actual participant behavior supports this view, as the owners of coal units, facing competition, typically exclude the 10 percent adder from their actual offers. The unadjusted markup is calculated as the difference between the price offer and the cost offer including the 10 percent adder in the cost offer. The adjusted markup is calculated as the difference between the price offer and the cost offer excluding the 10 percent adder from the cost offer. Even the adjusted markup underestimates the markup because coal units facing increased competitive pressure have excluded both the ten percent adder and some or all components of operating and maintenance cost. While both these elements are permitted under the definition of cost-based offers in the relevant PJM manual, they are not part of a competitive offer for a coal unit because they are not actually short run marginal costs, and market behavior reflected that fact.[57]

In order to accurately assess the markup behavior of market participants, real-time and day-ahead LMPs are decomposed using two different approaches. In the first approach, markup is the difference between the active offer of the marginal unit and the cost offer. In the second approach, the 10 percent markup is removed from the cost offers of coal units because coal units do not face the same cost uncertainty as gas fired CTs. The adjusted markup is calculated as the difference between the active offer and the cost offer excluding the 10 percent adder. The unadjusted markup is calculated as the

57 See PJM. "Manual 15: Cost Development Guidelines," Revision 27 (April 20, 2016).

difference between the active offer and the cost offer including the 10 percent adder in the cost offer.

Table 3-49 shows the mark-up component of the load-weighted LMP by fuel type and unit type using unadjusted and adjusted offers. The adjusted markup component of LMP decreased from $2.20 in the first six months of 2015 to $0.97 in the first six months of 2016. The adjusted markup contribution of coal units in the first six months of 2016 was -$0.55. The adjusted mark-up component of all gas-fired units in the first six months of 2016 was $1.59, an increase of $0.41 from the first six months of 2015. The markup component of wind units was $0.05. If a price-based offer is negative, but less negative than a cost-based offer, the markup is positive. In the first six months of 2016, among the wind units that were marginal, 2.98 percent had positive offer prices.

Table 3-49 Markup component of the overall PJM real-time, load-weighted, average LMP by primary fuel type and unit type: January through June, 2015 and 2016[58]

		2015 (Jan-Jun)		2016 (Jan-Jun)	
Fuel Type	Unit Type	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)
Coal	Steam	($0.96)	$0.79	($2.05)	($0.55)
Gas	CC	$1.21	$1.21	$1.18	$1.18
Gas	CT	($0.02)	($0.02)	$0.16	$0.16
Gas	Diesel	$0.01	$0.01	$0.00	$0.00
Gas	Steam	($0.01)	($0.01)	$0.24	$0.24
Municipal Waste	Steam	($0.02)	($0.02)	$0.00	$0.00
Oil	CC	$0.09	$0.09	$0.00	$0.00
Oil	CT	$0.06	$0.06	$0.01	$0.01
Oil	Diesel	$0.01	$0.01	$0.00	$0.00
Oil	Steam	$0.04	$0.04	$0.00	$0.00
Other	Steam	$0.03	$0.03	($0.12)	($0.12)
Uranium	Steam	$0.00	$0.00	$0.00	$0.00
Wind	Wind	$0.03	$0.03	$0.05	$0.05
Total		$0.46	$2.20	($0.53)	$0.97

58 The Unit Type Diesel refers to power generation using reciprocating internal combustion engines. Such Diesel units can use a variety of fuel types including diesel, natural gas, oil and gas from municipal waste.

Markup Component of Real-Time Price

Table 3-50 shows the markup component, calculated using unadjusted offers, of average prices and of average monthly on-peak and off-peak prices. Table 3-51 shows the markup component, calculated using adjusted offers, of average prices and of average monthly on-peak and off-peak prices. In the first six months of 2016, when using unadjusted cost offers, -$0.53 per MWh of the PJM real-time load-weighted average LMP was attributable to markup. Using adjusted cost offers, $0.97 per MWh of the PJM real-time load-weighted average LMP was attributable to markup. In the first six months of 2016, the peak markup component was highest in April, $1.74 per MWh using unadjusted cost offers and $3.50 per MWh using adjusted cost offers. This corresponds to 5.27 percent and 10.58 percent of the real-time load-weighted average LMP in April.

Table 3-50 Monthly markup components of real-time load-weighted LMP (Unadjusted): January through June, 2015 and 2016

	2015			2016		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
Jan	($1.42)	($2.62)	($0.15)	($1.65)	($1.56)	($1.74)
Feb	$4.62	$1.72	$7.46	($1.06)	($0.84)	($1.26)
Mar	$1.84	$1.82	$1.86	($0.35)	($1.22)	$0.42
Apr	($0.42)	($0.69)	($0.18)	$0.45	($0.90)	$1.74
May	($1.85)	($3.59)	($0.01)	($1.20)	($1.14)	($1.26)
Jun	($0.43)	($1.20)	$0.21	$0.81	$0.62	$0.97
Total	$0.46	($0.76)	$1.63	($0.53)	($0.86)	($0.21)

Table 3-51 Monthly markup components of real-time load-weighted LMP (Adjusted): January through June, 2015 and 2016

	2015			2016		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
Jan	$0.61	($0.61)	$1.90	($0.01)	($0.13)	$0.12
Feb	$6.44	$3.57	$9.24	$0.53	$0.58	$0.48
Mar	$3.71	$3.69	$3.74	$0.97	$0.01	$1.82
Apr	$1.22	$0.72	$1.65	$2.08	$0.61	$3.50
May	($0.45)	($2.41)	$1.64	$0.27	($0.06)	$0.60
Jun	$1.18	$0.06	$2.10	$2.17	$1.65	$2.60
Total	$2.20	$0.87	$3.48	$0.97	$0.43	$1.50

Hourly Markup Component of Real-Time Prices

Figure 3-32 shows the markup contribution to the hourly load-weighted LMP using unadjusted cost offers for the first six months of 2016 and 2015. Figure 3-33 shows the markup contribution to the hourly load-weighted LMP using adjusted cost offers for the first six months of 2016 and 2015. In 2015, high markups were seen during the cold winter days observed in February and March. In contrast, the first six months of 2016 had low markups.

Figure 3-32 Markup contribution to real-time hourly load-weighted LMP (Unadjusted): January through June, 2015 and 2016

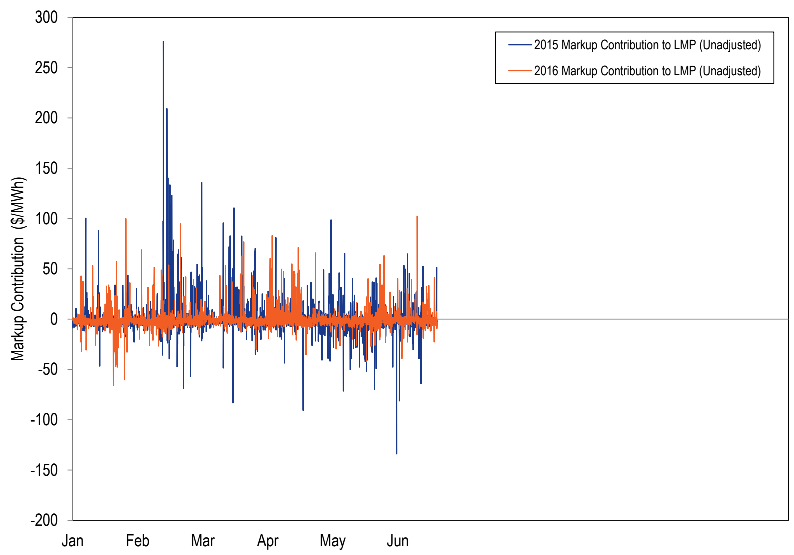


Figure 3-33 Markup contribution to real-time hourly load-weighted LMP (Adjusted): January through June, 2015 and 2016

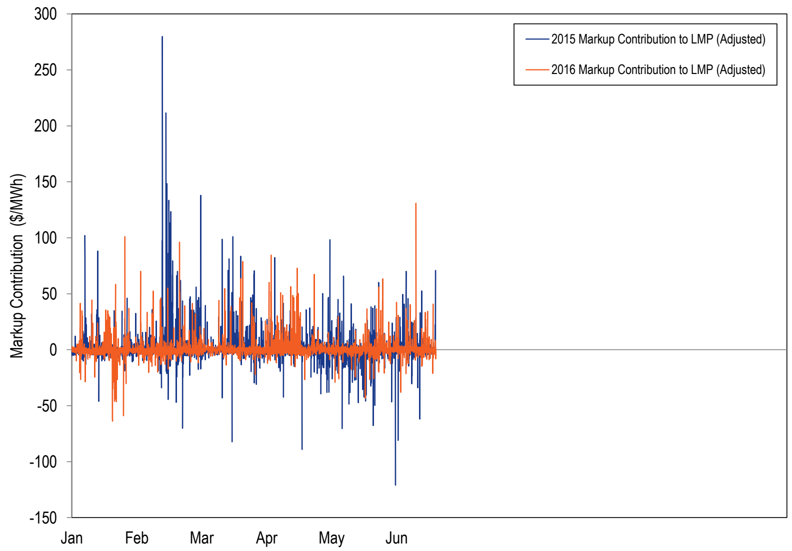


Table 3-52 Average real-time zonal markup component (Unadjusted): January through June, 2015 and 2016

	2015 (Jan-Jun)			2016 (Jan-Jun)		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
AECO	$0.11	($1.27)	$1.47	$0.67	$0.32	$1.02
AEP	$0.02	($1.29)	$1.30	($0.81)	($1.24)	($0.40)
APS	$0.96	($0.14)	$2.04	($0.84)	($1.22)	($0.47)
ATSI	$0.20	($1.14)	$1.48	($0.77)	($1.23)	($0.32)
BGE	$1.75	$1.01	$2.48	($2.22)	($2.59)	($1.85)
ComEd	($0.01)	($1.52)	$1.39	($0.59)	($0.69)	($0.50)
DAY	$0.26	($1.28)	$1.71	($0.97)	($1.27)	($0.70)
DEOK	$0.21	($1.51)	$1.86	($0.90)	($1.21)	($0.62)
DLCO	($0.05)	($1.30)	$1.13	($0.63)	($1.19)	($0.10)
DPL	$0.34	($0.78)	$1.44	$0.59	$0.31	$0.85
Dominion	$1.09	$0.29	$1.87	($1.23)	($1.38)	($1.08)
EKPC	$0.15	($1.55)	$1.91	($0.96)	($1.03)	($0.89)
JCPL	($0.06)	($1.13)	$0.93	$0.85	$0.43	$1.23
Met-Ed	$0.18	($1.01)	$1.30	$0.79	$0.32	$1.22
PECO	($0.00)	($1.02)	$0.96	$0.81	$0.43	$1.16
PENELEC	$0.74	($0.59)	$2.00	($0.14)	($0.69)	$0.37
PPL	$0.53	($0.79)	$1.78	$0.75	$0.26	$1.21
PSEG	$0.72	($0.68)	$2.03	$0.79	$0.42	$1.14
Pepco	$1.47	$0.57	$2.32	($1.61)	($1.89)	($1.36)
RECO	$1.14	($1.09)	$3.08	$0.87	$0.24	$1.42

Markup Component of Real-Time Zonal Prices

The unit markup component of average real-time price using unadjusted offers is shown for each zone for the first six months of 2015 and the first six months of 2016 in Table 3-52 and for adjusted offers in Table 3-53. The smallest zonal all hours average markup component using unadjusted offers for the first six month of 2016 was in the BGE Zone, -$2.22 per MWh, while the highest was in the RECO Control Zone, $0.87 per MWh. The smallest zonal on peak average markup was in the BGE Control Zone, -$1.85 per MWh, while the highest was in the RECO Control Zone, $1.42 per MWh.

Table 3-53 Average real-time zonal markup component (Adjusted): January through June, 2015 and 2016

	2015 (Jan-Jun)			2016 (Jan-Jun)		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
AECO	$1.41	$0.02	$2.79	$1.37	$0.95	$1.79
AEP	$1.85	$0.39	$3.27	$0.83	$0.18	$1.46
APS	$2.80	$1.59	$4.00	$0.83	$0.23	$1.42
ATSI	$2.09	$0.60	$3.50	$0.80	$0.15	$1.42
BGE	$4.12	$3.16	$5.05	$0.53	($0.20)	$1.24
ComEd	$1.59	($0.07)	$3.12	$0.88	$0.51	$1.23
DAY	$2.14	$0.41	$3.76	$0.72	$0.17	$1.23
DEOK	$2.02	$0.13	$3.83	$0.73	$0.19	$1.25
DLCO	$1.79	$0.40	$3.10	$0.90	$0.15	$1.61
DPL	$1.73	$0.63	$2.83	$1.31	$0.97	$1.65
Dominion	$3.10	$2.16	$4.03	$0.76	$0.30	$1.21
EKPC	$1.97	$0.17	$3.83	$0.74	$0.41	$1.08
JCPL	$1.20	$0.13	$2.19	$1.62	$1.10	$2.11
Met-Ed	$1.52	$0.27	$2.68	$1.53	$0.95	$2.07
PECO	$1.28	$0.28	$2.23	$1.49	$1.05	$1.91
PENELEC	$2.45	$1.00	$3.82	$1.12	$0.43	$1.76
PPL	$1.84	$0.51	$3.10	$1.54	$0.94	$2.10
PSEG	$2.16	$0.70	$3.52	$1.57	$1.07	$2.04
Pepco	$3.64	$2.54	$4.67	$0.66	$0.05	$1.23
RECO	$2.78	$0.52	$4.74	$1.71	$0.94	$2.38

Markup by Real Time Price Levels

Table 3-54 shows the average markup component of observed prices, based on the unadjusted cost-based offers and adjusted cost-based offers of the marginal units, when the PJM average LMP was in the identified price range.

Table 3-54 Average real-time markup component (By price category, unadjusted): January through June, 2015 and 2016

	2015 (Jan-Jun)		2016 (Jan-Jun)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	$0.46	100.0%	($1.15)	63.9%
$25 to $50	$0.00	0.0%	($0.37)	31.9%
$50 to $75	$0.00	0.0%	$0.54	2.9%
$75 to $100	$0.00	0.0%	$0.29	0.8%
$100 to $125	$0.00	0.0%	$0.09	0.4%
$125 to $150	$0.00	0.0%	$0.04	0.1%
>= $150	$0.00	0.0%	$0.03	0.1%

Table 3-55 Average real-time markup component (By price category, adjusted): January through June, 2015 and 2016

	2015 (Jan-Jun)		2016 (Jan-Jun)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	$2.22	100.0%	($0.38)	63.9%
$25 to $50	$0.00	0.0%	$0.32	31.9%
$50 to $75	$0.00	0.0%	$0.57	2.9%
$75 to $100	$0.00	0.0%	$0.29	0.8%
$100 to $125	$0.00	0.0%	$0.10	0.4%
$125 to $150	$0.00	0.0%	$0.04	0.1%
>= $150	$0.00	0.0%	$0.03	0.1%

Day-Ahead Markup

Markup Component of Day-Ahead Price by Fuel, Unit Type

The markup component of the PJM day-ahead, load-weighted average LMP by primary fuel and unit type is shown in Table 3-56. INC, DEC and up to congestion transactions have zero markups. Up to congestion transactions were 83.3 percent of marginal resources, INCs were 3.8 percent of marginal resources, and DECs were 7.3 percent of marginal resources in the first six months of 2016. The share of marginal up to congestion transactions decreased significantly beginning on September 8, 2014, as a result of the FERC's UTC uplift refund notice which became effective on September 8, 2014.[59] The adjusted markup of coal units is calculated as the difference between the price

59 See 18 CFR § 385.213 (2014).

offer, and the cost offer excluding the 10 percent adder. Table 3-56 shows the markup component of LMP for marginal generating resources. Generating resources were only 5.5 percent of marginal resources in the first six months of 2016. The markup component of LMP for marginal generating resources increased in coal-fired steam units and decreased in oil-fired CT units. The markup component of LMP for coal units increased from $0.63 in the first six months of 2015 to $1.29 in the first six months of 2016 using adjusted offers. The markup component of LMP for gas-fired CCs increased from -$0.03 in the first six months of 2015 to $0.00 in the first six months of 2016 using adjusted offers.

Table 3-56 Markup component of the annual PJM day-ahead, load-weighted, average LMP by primary fuel type and unit type: January through June, 2015 and 2016

		2015 (Jan - Jun)		2016 (Jan - Jun)	
Fuel Type	Unit Type	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)
Coal	Steam	($0.37)	$0.63	$0.37	$1.29
Gas	CC	($0.03)	($0.03)	$0.00	$0.00
Gas	CT	$0.11	$0.11	$0.03	$0.03
Gas	Diesel	$0.05	$0.05	$0.00	$0.00
Gas	Steam	$0.08	$0.08	$0.30	$0.30
Municipal Waste	Steam	($0.00)	($0.00)	$0.02	$0.02
Oil	CC	$0.07	$0.07	$0.00	$0.00
Oil	CT	$0.03	$0.03	($0.01)	($0.01)
Oil	Diesel	$0.00	$0.00	$0.00	$0.00
Oil	Steam	$0.14	$0.14	($0.33)	($0.33)
Other	Steam	($0.00)	($0.00)	($0.00)	($0.00)
Uranium	Steam	$0.00	$0.00	($0.01)	($0.01)
Wind	Wind	$0.03	$0.03	$0.01	$0.01
Total		$0.09	$1.09	$0.38	$1.29

Markup Component of Day-Ahead Price

The markup component of price is the difference between the system price, when the system price is determined by the active offers of the marginal units, whether price or cost-based, and the system price, based on the cost-based offers of those marginal units. Only hours when generating units were marginal on either priced-based offers or on cost-based offers were included in the markup calculation.

Table 3-57 shows the markup component of average prices and of average monthly on-peak and off-peak prices using unadjusted offers. Table 3-58 shows the markup component of average prices and of average monthly on-peak and off-peak prices using adjusted offers. In the first six months of 2016, when using adjusted cost-offers, $1.29 per MWh of the PJM day-ahead load-weighted average LMP was attributable to markup. In the first six months of 2016, the peak markup component was highest in January, $3.52 per MWh using adjusted cost offers. Using adjusted cost offers, the markup component in the first six months of 2016 decreased in every month except January, March and April from the first six months of 2015. Using adjusted cost offers, the markup component increased from -$0.29 to $2.26 in January.

Table 3-57 Monthly markup components of day-ahead (Unadjusted), load-weighted LMP: January through June, 2015 and 2016

	2015			2016		
	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
Jan	($1.98)	($1.27)	($2.66)	$1.12	$2.50	($0.11)
Feb	$1.39	$3.35	($0.62)	$0.20	$0.99	($0.65)
Mar	($0.43)	$0.49	($1.38)	$0.23	$1.11	($0.78)
Apr	($0.79)	($0.06)	($1.63)	$0.30	$1.42	($0.87)
May	$0.75	$0.70	$0.80	($0.28)	($0.12)	($0.45)
Jun	$1.66	$2.32	$0.85	$0.53	$1.95	($1.20)
Annual	$0.09	$0.97	($0.83)	$0.38	$1.35	($0.65)

Table 3-58 Monthly markup components of day-ahead (Adjusted), load-weighted LMP: January through June, 2015 and 2016

	2015			2016		
	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
Jan	($0.29)	$0.21	($0.76)	$2.26	$3.52	$1.13
Feb	$2.81	$4.51	$1.06	$1.20	$2.01	$0.35
Mar	$1.01	$1.79	$0.21	$1.16	$2.03	$0.17
Apr	$0.50	$1.03	($0.11)	$1.11	$2.02	$0.17
May	$0.75	$0.70	$0.80	$0.49	$0.59	$0.38
Jun	$1.66	$2.32	$0.85	$1.32	$2.71	($0.37)
Annual	$1.09	$1.82	$0.32	$1.29	$2.20	$0.34

Markup Component of Day-Ahead Zonal Prices

The markup component of annual average day-ahead price using unadjusted offers is shown for each zone in Table 3-59. The markup component of annual average day-ahead price using adjusted offers is shown for each zone in Table 3-60. Using unadjusted offers, the markup component of the average day-ahead price increased in all zones from the first six months of 2015 to the first six months of 2016 except AECO, DPL, JCPL, PECO, PSEG and RECO control zones. The smallest zonal all hours average markup component using adjusted offers for the first six months of 2016 was in the ComEd Zone, $1.06 per MWh, while the highest was in the DPL Control Zone, $1.70 per MWh. The smallest zonal on peak average markup using adjusted offers was in the ComEd Control Zone, $1.89 per MWh, while the highest was in the DPL Control Zone, $2.63 per MWh.

Table 3-59 Day-ahead, average, zonal markup component (Unadjusted): January through June, 2015 and 2016

	2015 (Jan - Jun)			2016 (Jan - Jun)		
	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
AECO	$1.79	$3.94	($0.48)	$0.63	$1.74	($0.55)
AEP	$0.00	$1.06	($1.07)	$0.26	$1.18	($0.69)
AP	($0.21)	$0.23	($0.65)	$0.34	$1.30	($0.64)
ATSI	($0.38)	$0.42	($1.24)	$0.29	$1.19	($0.67)
BGE	($0.78)	($0.79)	($0.77)	$0.38	$1.43	($0.73)
ComEd	$0.01	$1.15	($1.23)	$0.15	$1.04	($0.83)
DAY	($0.28)	$0.87	($1.52)	$0.25	$1.14	($0.71)
DEOK	($0.22)	$0.81	($1.31)	$0.21	$1.09	($0.72)
DLCO	($0.78)	($0.25)	($1.34)	$0.33	$1.25	($0.66)
Dominion	$0.02	$0.36	($0.33)	$0.49	$1.46	($0.50)
DPL	$1.24	$2.99	($0.55)	$0.96	$1.95	($0.05)
EKPC	($0.02)	$1.11	($1.13)	$0.28	$1.15	($0.59)
JCPL	$1.01	$2.42	($0.56)	$0.68	$1.72	($0.48)
Met-Ed	$0.43	$1.28	($0.48)	$0.52	$1.59	($0.64)
PECO	$0.75	$1.91	($0.49)	$0.61	$1.71	($0.56)
PENELEC	$0.02	$0.71	($0.69)	$0.29	$1.21	($0.64)
Pepco	($0.05)	$0.52	($0.64)	$0.34	$1.41	($0.78)
PPL	$0.54	$1.61	($0.59)	$0.57	$1.67	($0.60)
PSEG	$0.95	$2.29	($0.52)	$0.64	$1.76	($0.61)
RECO	$0.85	$2.06	($0.55)	$0.53	$1.59	($0.68)

Table 3-60 Day-ahead, average, zonal markup component (Adjusted): January through June, 2015 and 2016

	2015 (Jan - Jun)			2016 (Jan - Jun)		
	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
AECO	$2.61	$4.61	$0.50	$1.35	$2.43	$0.21
AEP	$1.09	$1.97	$0.18	$1.22	$2.05	$0.37
AP	$0.83	$1.14	$0.51	$1.32	$2.19	$0.42
ATSI	$0.75	$1.41	$0.05	$1.25	$2.06	$0.38
BGE	$0.28	$0.11	$0.46	$1.48	$2.46	$0.45
ComEd	$1.08	$2.10	($0.02)	$1.06	$1.89	$0.16
DAY	$0.83	$1.81	($0.23)	$1.24	$2.04	$0.37
DEOK	$0.85	$1.73	($0.07)	$1.17	$1.95	$0.33
DLCO	$0.31	$0.69	($0.10)	$1.28	$2.11	$0.38
Dominion	$0.99	$1.19	$0.79	$1.48	$2.40	$0.55
DPL	$2.06	$3.63	$0.45	$1.70	$2.63	$0.74
EKPC	$1.08	$2.02	$0.16	$1.25	$2.00	$0.49
JCPL	$1.85	$3.11	$0.44	$1.44	$2.43	$0.33
Met-Ed	$1.27	$1.98	$0.51	$1.29	$2.32	$0.18
PECO	$1.56	$2.58	$0.47	$1.36	$2.40	$0.25
PENELEC	$0.95	$1.47	$0.43	$1.17	$2.02	$0.30
Pepco	$0.97	$1.41	$0.50	$1.37	$2.37	$0.33
PPL	$1.41	$2.33	$0.43	$1.34	$2.39	$0.22
PSEG	$1.75	$2.94	$0.45	$1.37	$2.44	$0.18
RECO	$1.65	$2.72	$0.41	$1.26	$2.28	$0.09

Markup by Day-Ahead Price Levels

Table 3-61 and Table 3-62 show the average markup component of observed prices, based on the unadjusted cost-based offers and adjusted cost-based offers of the marginal units, when the PJM system LMP was in the identified price range.

Table 3-61 Average, day-ahead markup (By LMP category, unadjusted): January through June, 2015 and 2016

	2015 (Jan - Jun)		2016 (Jan - Jun)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	($0.68)	17.9%	($1.07)	51.2%
$25 to $50	($0.38)	66.2%	$1.37	47.3%
$50 to $75	$1.72	7.6%	$4.59	1.4%
$75 to $100	($3.54)	4.0%	$5.20	0.1%
$100 to $125	$1.12	2.1%	$0.00	0.0%
$125 to $150	$10.26	0.9%	$0.00	0.0%
>= $150	$13.21	1.3%	$0.00	0.0%

Table 3-62 Average, day-ahead markup (By LMP category, adjusted): January through June, 2015 and 2016

	2015 (Jan - Jun)		2016 (Jan - Jun)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	($0.04)	17.9%	$0.10	51.2%
$25 to $50	$0.90	66.2%	$2.29	47.3%
$50 to $75	$2.45	7.6%	$4.96	1.4%
$75 to $100	($2.87)	4.0%	$5.20	0.1%
$100 to $125	$1.80	2.1%	$0.00	0.0%
$125 to $150	$10.93	0.9%	$0.00	0.0%
>= $150	$13.60	1.3%	$0.00	0.0%

Prices

The conduct of individual market entities within a market structure is reflected in market prices. PJM locational marginal prices (LMPs) are a direct measure of market performance. Price level is a good, general indicator of market performance, although overall price results must be interpreted carefully because of the multiple factors that affect them. Among other things, overall average prices reflect changes in supply and demand, generation fuel mix, the cost of fuel, emission related expenses, markup and local price differences caused by congestion. PJM also may administratively set prices with the creation of a closed loop interface related to demand side resources or reactive power.

Real-time and day-ahead energy market load-weighted prices were 36.0 percent and 44.7 percent lower in the first six months of 2016 than in the first six months of 2015 as a result of lower fuel costs and lower demand in 2016. Coal and natural gas prices decreased in 2016. Comparing fuel prices in the first six months of 2016 to the first six months of 2015, the price of Northern Appalachian coal was 23.5 percent lower; the price of Central Appalachian coal was 16.7 percent lower; the price of Powder River Basin coal was 12.7 percent lower; the price of eastern natural gas was 56.8 percent lower; and the price of western natural gas was 25.4 percent lower.

PJM real-time energy market prices decreased in the first six months of 2016 compared to the first six months of 2015. The average LMP was 33.5 percent lower in the first six months of 2016 than in the first six months of 2015, $25.84 per MWh versus $38.87 per MWh. The load-weighted average LMP was 36.0 percent lower in the first six months of 2016 than in the first six months of 2015, $27.09 per MWh versus $42.30 per MWh.

The fuel-cost adjusted, load-weighted, average LMP in the first six months of 2016 was 18.8 percent higher than the load-weighted, average LMP for the first six months of 2016. If fuel and emission costs in the first six months of 2016 had been the same as in the first six months of 2015, holding everything else constant, the load-weighted LMP would have been higher, $32.17 per MWh instead of the observed $27.09 per MWh.

PJM day-ahead energy market prices decreased in the first six months of 2016 compared to the first six months of 2015. The average LMP was 34.4 percent lower in the first six months of 2016 than in the first six months of 2015, $26.24 per MWh versus $39.98 per MWh. The day-ahead load-weighted average LMP was 36.8 percent lower in the first six months of 2016 than in the first six months of 2015, $27.33 per MWh versus $43.26 per MWh.

Occasionally, in a constrained market, the LMPs at some pricing nodes can exceed the offer price of the highest cleared generator in the supply stack.[60] In the nodal pricing system, the LMP at a pricing node is the total cost of meeting incremental demand at that node. When there are binding transmission constraints, satisfying the marginal increase in demand at a node may require increasing the output of some generators while simultaneously decreasing the output of other generators, such that the transmission constraints are not violated. The total cost of redispatching multiple generators can at times exceed the cost of marginally increasing the output of the most expensive generator offered. Thus the LMPs at some pricing nodes exceed $1,000 per MWh, the cap on the generators' offer price in the PJM market.[61]

Real-Time LMP

Real-time average LMP is the hourly average LMP for the PJM Real-Time Energy Market.[62]

Real-Time Average LMP

PJM Real-Time Average LMP Duration

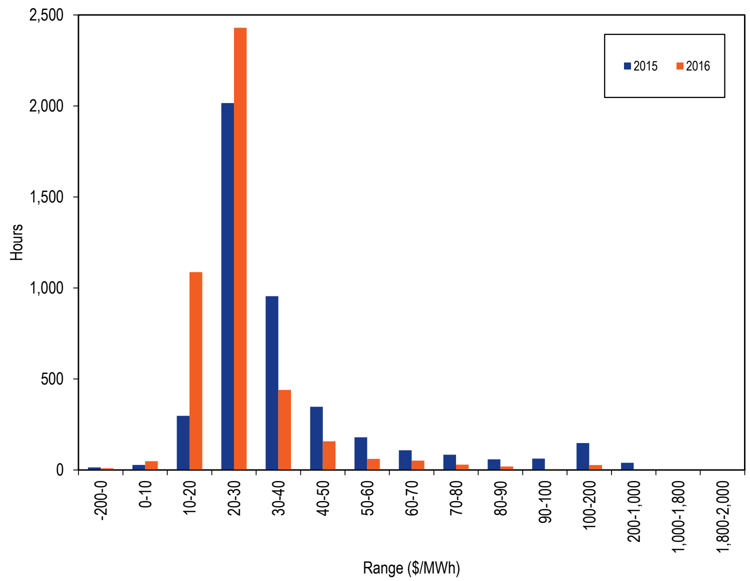
Figure 3-34 shows the hourly distribution of PJM real-time average LMP for the first six months of 2015 and 2016.

60 See O'Neill R. P, Mead D. and Malvadkar P. "On Market Clearing Prices Higher than the Highest Bid and Other Almost Paranormal Phenomena." *The Electricity Journal 2005*; 18(2): pp 19-27.

61 The offer cap in PJM was temporarily increased to $1,800 per MWh prior to the winter of 2014/2015. A new cap of $2,000 per MWh, only for offers with costs exceeding $1,000 per MWh, went into effect on December, 14, 2015, 153 FERC ¶ 61,289 (2015).

62 See the *MMU Technical Reference for the PJM Markets*, at "Calculating Locational Marginal Price," for detailed definition of Real-Time LMP. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

Figure 3-34 Average LMP for the PJM Real-Time Energy Market: January through June, 2015 and 2016



PJM Real-Time, Average LMP

Table 3-63 shows the PJM real-time, average LMP for the first six months of each year from 1998 through 2016.[63]

Table 3-63 PJM real-time, average LMP (Dollars per MWh): January through June, 1998 through 2016

	Real-Time LMP			Year-to-Year Change		
Jan-Jun	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$20.13	$15.90	$15.59	NA	NA	NA
1999	$22.94	$17.84	$41.16	14.0%	12.2%	164.0%
2000	$25.38	$18.03	$25.65	10.6%	1.1%	(37.7%)
2001	$33.10	$25.69	$21.11	30.4%	42.5%	(17.7%)
2002	$24.10	$19.64	$13.21	(27.2%)	(23.6%)	(37.4%)
2003	$41.31	$33.74	$27.81	71.4%	71.8%	110.6%
2004	$44.99	$40.75	$22.97	8.9%	20.8%	(17.4%)
2005	$45.71	$39.80	$23.51	1.6%	(2.3%)	2.3%
2006	$49.36	$43.46	$25.26	8.0%	9.2%	7.5%
2007	$55.03	$48.05	$31.42	11.5%	10.6%	24.4%
2008	$70.19	$59.53	$41.77	27.6%	23.9%	33.0%
2009	$40.12	$35.42	$19.30	(42.8%)	(40.5%)	(53.8%)
2010	$43.27	$37.11	$22.20	7.9%	4.8%	15.0%
2011	$45.51	$37.40	$32.52	5.2%	0.8%	46.5%
2012	$29.74	$28.32	$16.10	(34.6%)	(24.3%)	(50.5%)
2013	$36.56	$32.79	$17.18	22.9%	15.8%	6.7%
2014	$62.14	$39.69	$88.87	69.9%	21.0%	417.4%
2015	$38.87	$29.04	$34.04	(37.4%)	(26.8%)	(61.7%)
2016	$25.84	$23.17	$13.61	(33.5%)	(20.2%)	(60.0%)

Real-Time, Load-Weighted, Average LMP

Higher demand (load) generally results in higher prices, all else constant. As a result, load-weighted, average prices are generally higher than average prices. Load-weighted LMP reflects the average LMP paid for actual MWh consumed during a year. Load-weighted, average LMP is the average of PJM hourly LMP, each weighted by the PJM total hourly load. The real-time, load-weighted, average LMP decreased by 36.0 percent compared to the first six months of 2015.

63 The system average LMP is the average of the hourly LMP without any weighting. The only exception is that market-clearing prices (MCPs) are included for January to April 1998. MCP was the single market-clearing price calculated by PJM prior to implementation of LMP.

PJM Real-Time, Load-Weighted, Average LMP

Table 3-64 shows the PJM real-time, load-weighted, average LMP for the first six months of each year from 1998 through 2016.

Table 3-64 PJM real-time, load-weighted, average LMP (Dollars per MWh): January through June, 1998 through 2016

	Real-Time, Load-Weighted, Average LMP			Year-to-Year Change		
Jan-Jun	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$21.66	$16.80	$18.39	NA	NA	NA
1999	$25.34	$18.59	$52.06	17.0%	10.7%	183.1%
2000	$27.76	$18.91	$29.69	9.5%	1.7%	(43.0%)
2001	$35.27	$27.88	$22.12	27.0%	47.4%	(25.5%)
2002	$25.93	$20.67	$14.62	(26.5%)	(25.9%)	(33.9%)
2003	$44.43	$37.98	$28.55	71.4%	83.8%	95.2%
2004	$47.62	$43.96	$23.30	7.2%	15.8%	(18.4%)
2005	$48.67	$42.30	$24.81	2.2%	(3.8%)	6.5%
2006	$51.83	$45.79	$26.54	6.5%	8.3%	7.0%
2007	$58.32	$52.52	$32.39	12.5%	14.7%	22.1%
2008	$74.77	$64.26	$44.25	28.2%	22.4%	36.6%
2009	$42.48	$36.95	$20.61	(43.2%)	(42.5%)	(53.4%)
2010	$45.75	$38.78	$23.60	7.7%	5.0%	14.5%
2011	$48.47	$38.63	$37.59	5.9%	(0.4%)	59.3%
2012	$31.21	$28.98	$17.69	(35.6%)	(25.0%)	(52.9%)
2013	$37.96	$33.58	$18.54	21.6%	15.9%	4.8%
2014	$69.92	$42.61	$103.35	84.2%	26.9%	457.6%
2015	$42.30	$30.34	$37.85	(39.5%)	(28.8%)	(63.4%)
2016	$27.09	$23.82	$14.49	(36.0%)	(21.5%)	(61.7%)

Table 3-65 shows zonal real-time, and real-time, load-weighted, average LMP for the first six months of 2015 and 2016.

Table 3-65 Zone real-time and real-time, load-weighted, average LMP (Dollars per MWh): January through June, 2015 and 2016

	Real-Time Average LMP			Real-Time, Load-Weighted, Average LMP		
Zone	2015 (Jan-Jun)	2016 (Jan-Jun)	Percent Change	2015 (Jan-Jun)	2016 (Jan-Jun)	Percent Change
AECO	$41.58	$23.53	(43.4%)	$45.10	$25.12	(44.3%)
AEP	$35.25	$26.03	(26.1%)	$37.76	$27.09	(28.3%)
AP	$40.67	$26.60	(34.6%)	$44.73	$27.84	(37.8%)
ATSI	$35.82	$26.07	(27.2%)	$37.75	$27.05	(28.3%)
BGE	$48.89	$34.12	(30.2%)	$54.57	$36.27	(33.5%)
ComEd	$29.91	$23.59	(21.2%)	$31.54	$24.66	(21.8%)
Day	$35.45	$26.11	(26.3%)	$37.79	$27.18	(28.1%)
DEOK	$34.15	$25.30	(25.9%)	$36.50	$26.34	(27.8%)
DLCO	$33.23	$25.46	(23.4%)	$34.87	$26.50	(24.0%)
Dominion	$43.48	$28.90	(33.5%)	$49.19	$30.77	(37.4%)
DPL	$44.95	$25.47	(43.3%)	$52.35	$27.61	(47.3%)
EKPC	$32.82	$25.20	(23.2%)	$36.36	$26.40	(27.4%)
JCPL	$41.20	$22.50	(45.4%)	$45.14	$24.08	(46.6%)
Met-Ed	$41.09	$22.43	(45.4%)	$45.80	$23.71	(48.2%)
PECO	$40.41	$22.01	(45.5%)	$44.65	$23.37	(47.7%)
PENELEC	$40.07	$24.78	(38.2%)	$43.29	$25.72	(40.6%)
Pepco	$45.42	$30.67	(32.5%)	$50.34	$32.45	(35.5%)
PPL	$40.68	$22.48	(44.7%)	$46.09	$23.76	(48.4%)
PSEG	$44.83	$22.83	(49.1%)	$48.14	$24.15	(49.8%)
RECO	$45.63	$22.86	(49.9%)	$48.24	$24.45	(49.3%)
PJM	$42.30	$27.09	(36.0%)	$42.30	$27.09	(36.0%)

Figure 3-35 is a contour map of the real-time, load-weighted, average LMP in the first six months of 2016. In the legend, green represents the system marginal price (SMP) and each increment to the right and left of the SMP represents five percent of the pricing nodes above and below the SMP. The LMP for each five percent increment is the highest nodal average LMP for that set of nodes. Each increment to the left of the SMP is the lowest nodal average LMP for that set of nodes.

months of 2015, the price of Northern Appalachian coal was 23.5 percent lower; the price of Central Appalachian coal was 16.7 percent lower; the price of Powder River Basin coal was 12.7 percent lower; the price of eastern natural gas was 56.8 percent lower; and the price of western natural gas was 25.4 percent lower. Figure 3-38 shows monthly average spot fuel prices.[65]

Figure 3-38 Spot average fuel price comparison with fuel delivery charges: 2012 through June 2016 ($/MMBtu)

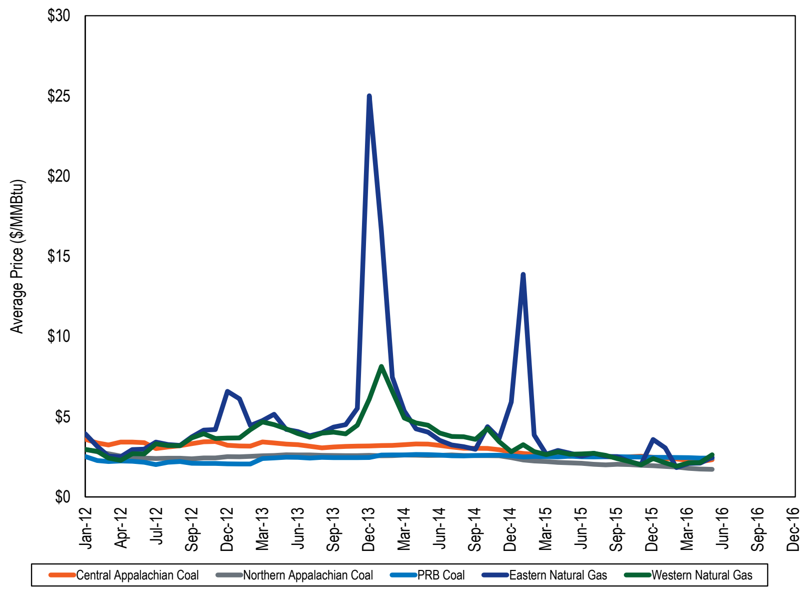


Table 3-66 compares the first six months of 2016 PJM real-time fuel-cost adjusted, load-weighted, average LMP to the first six months of 2016 load-weighted, average LMP.[66] The real-time fuel-cost adjusted, load-weighted, average LMP for the first six months of 2016 was 18.8 percent higher than the real-time load-weighted, average LMP for the first six months of 2016.

65 Eastern natural gas consists of the average of Texas M3, Transco Zone 6 non-NY, Transco Zone 6 NY and Transco Zone 5 daily fuel price indices. Western natural gas prices are the average of Dominion North Point, Columbia Appalachia and Chicago Citygate daily fuel price indices. Coal prices are the average of daily fuel prices for Central Appalachian coal, Northern Appalachian coal, and Powder River Basin coal. All fuel prices are from Platts.

66 The fuel-cost adjusted LMP reflects both the fuel and emissions where applicable, including NO_x, CO_2 and SO_x costs.

The real-time, fuel-cost adjusted, load-weighted, average LMP for the first six months of 2016 was 23.9 percent lower than the real-time load-weighted LMP for the first six months of 2015. If fuel and emissions costs in the first six months of 2016 had been the same as in the first six months of 2015, holding everything else constant, the real-time load-weighted LMP in the first six months of 2016 would have been higher, $32.17 per MWh instead of the observed $27.09 per MWh.

Table 3-66 PJM real-time annual, fuel-cost adjusted, load-weighted average LMP (Dollars per MWh): six months over six months

	2016 Load-Weighted LMP	2016 Fuel-Cost Adjusted, Load-Weighted LMP	Change
Average	$27.09	$32.17	18.8%
	2015 Load-Weighted LMP	2016 Fuel-Cost Adjusted, Load-Weighted LMP	Change
Average	$42.30	$32.17	(23.9%)
	2015 Load-Weighted LMP	2016 Load-Weighted LMP	Change
Average	$42.30	$27.09	(36.0%)

Table 3-67 shows the impact of each fuel type on the difference between the fuel-cost adjusted, load-weighted average LMP and the load-weighted LMP in the first six months of 2016. Table 3-67 shows that lower coal and natural gas prices explain almost all of the fuel-cost related decrease in the real time annual load-weighted average LMP in the first six months of 2016.

Table 3-67 Change in PJM real-time annual, fuel-cost adjusted, load-weighted average LMP (Dollars per MWh) by Fuel-type: quarter over quarter

Fuel Type	Share of Change in Fuel Cost Adjusted, Load Weighted LMP	Percent
Coal	($1.97)	38.7%
Gas	($2.98)	58.7%
Municipal Waste	$0.00	0.0%
Oil	($0.14)	2.7%
Other	$0.00	(0.0%)
Uranium	$0.00	(0.0%)
Wind	($0.00)	0.0%
Total	($5.08)	100.0%

months of 2015, the price of Northern Appalachian coal was 23.5 percent lower; the price of Central Appalachian coal was 16.7 percent lower; the price of Powder River Basin coal was 12.7 percent lower; the price of eastern natural gas was 56.8 percent lower; and the price of western natural gas was 25.4 percent lower. Figure 3-38 shows monthly average spot fuel prices.[65]

Figure 3-38 Spot average fuel price comparison with fuel delivery charges: 2012 through June 2016 ($/MMBtu)

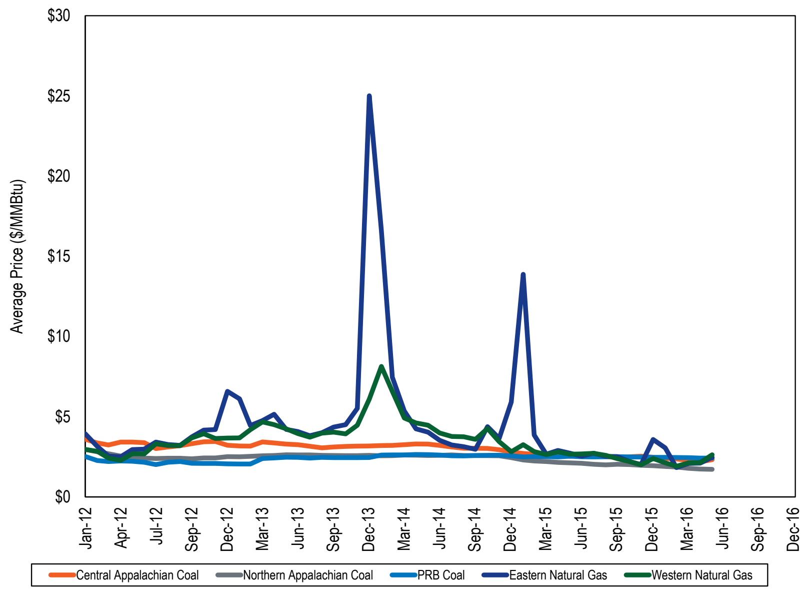


Table 3-66 compares the first six months of 2016 PJM real-time fuel-cost adjusted, load-weighted, average LMP to the first six months of 2016 load-weighted, average LMP.[66] The real-time fuel-cost adjusted, load-weighted, average LMP for the first six months of 2016 was 18.8 percent higher than the real-time load-weighted, average LMP for the first six months of 2016.

The real-time, fuel-cost adjusted, load-weighted, average LMP for the first six months of 2016 was 23.9 percent lower than the real-time load-weighted LMP for the first six months of 2015. If fuel and emissions costs in the first six months of 2016 had been the same as in the first six months of 2015, holding everything else constant, the real-time load-weighted LMP in the first six months of 2016 would have been higher, $32.17 per MWh instead of the observed $27.09 per MWh.

Table 3-66 PJM real-time annual, fuel-cost adjusted, load-weighted average LMP (Dollars per MWh): six months over six months

	2016 Load-Weighted LMP	2016 Fuel-Cost Adjusted, Load-Weighted LMP	Change
Average	$27.09	$32.17	18.8%
	2015 Load-Weighted LMP	2016 Fuel-Cost Adjusted, Load-Weighted LMP	Change
Average	$42.30	$32.17	(23.9%)
	2015 Load-Weighted LMP	2016 Load-Weighted LMP	Change
Average	$42.30	$27.09	(36.0%)

Table 3-67 shows the impact of each fuel type on the difference between the fuel-cost adjusted, load-weighted average LMP and the load-weighted LMP in the first six months of 2016. Table 3-67 shows that lower coal and natural gas prices explain almost all of the fuel-cost related decrease in the real time annual load-weighted average LMP in the first six months of 2016.

Table 3-67 Change in PJM real-time annual, fuel-cost adjusted, load-weighted average LMP (Dollars per MWh) by Fuel-type: quarter over quarter

Fuel Type	Share of Change in Fuel Cost Adjusted, Load Weighted LMP	Percent
Coal	($1.97)	38.7%
Gas	($2.98)	58.7%
Municipal Waste	$0.00	0.0%
Oil	($0.14)	2.7%
Other	$0.00	(0.0%)
Uranium	$0.00	(0.0%)
Wind	($0.00)	0.0%
Total	($5.08)	100.0%

65 Eastern natural gas consists of the average of Texas M3, Transco Zone 6 non-NY, Transco Zone 6 NY and Transco Zone 5 daily fuel price indices. Western natural gas prices are the average of Dominion North Point, Columbia Appalachia and Chicago Citygate daily fuel price indices. Coal prices are the average of daily fuel prices for Central Appalachian coal, Northern Appalachian coal, and Powder River Basin coal. All fuel prices are from Platts.

66 The fuel-cost adjusted LMP reflects both the fuel and emissions where applicable, including NO_x, CO_2 and SO_x, costs.

Components of Real-Time, Load-Weighted LMP

LMPs result from the operation of a market based on security-constrained, economic (least-cost) dispatch (SCED) in which marginal units determine system LMPs, based on their offers and five minute ahead forecasts of system conditions. Those offers can be decomposed into components including fuel costs, emission costs, variable operation and maintenance costs, markup, FMU adder and the 10 percent cost adder. As a result, it is possible to decompose LMP by the components of unit offers.

Cost offers of marginal units are separated into their component parts. The fuel related component is based on unit specific heat rates and spot fuel prices. Emission costs are calculated using spot prices for NO_x, SO_2 and CO_2 emission credits, emission rates for NO_x, emission rates for SO_2 and emission rates for CO_2. The CO_2 emission costs are applicable to PJM units in the PJM states that participate in RGGI: Delaware and Maryland.[67] The FMU adder is the calculated contribution of the FMU and AU adders to LMP that results when units with FMU or AU adders are marginal.

Since the implementation of scarcity pricing on October 1, 2012, PJM jointly optimizes the commitment and dispatch of energy and ancillary services. In periods of scarcity when generators providing energy have to be dispatched down from their economic operating level to meet reserve requirements, the joint optimization of energy and reserves takes into account the opportunity cost of the reduced generation and the associated incremental cost to maintain reserves. If a unit incurring such opportunity costs is a marginal resource in the energy market, this opportunity cost will contribute to LMP. In addition, in periods when generators providing energy cannot meet the reserve requirements, PJM can invoke shortage pricing. PJM invoked shortage pricing on January 6 and January 7 of 2014.[68] During the shortage conditions, the LMPs of marginal generators reflect the cost of not meeting the reserve requirements, the scarcity adder, which is defined by the operating reserve demand curve.

67 New Jersey withdrew from RGGI, effective January 1, 2012.

68 PJM triggered shortage pricing on January 6, 2015, following a RTO-wide voltage reduction action. PJM triggered shortage pricing on January 7, 2014, due to a RTO-wide shortage of synchronized reserve.

LMP may, at times, be set by transmission penalty factors. When a transmission constraint is binding and there are no generation alternatives to resolve the constraint, system operators may allow the transmission limit to be violated. When this occurs, the shadow price of the constraint is set by transmission penalty factors. The shadow price directly affects the LMP. Transmission penalty factors are administratively determined and can be thought of as a form of locational scarcity pricing.

Transmission penalty factors should be stated explicitly and publicly and applied without discretion. Penalty factors should be set high enough so that they do not act to suppress prices based on available generator solutions. But rather than permit the transmission penalty factor to set the shadow price, PJM has been using a procedure called constraint relaxation logic to prevent the penalty factors from setting the shadow price of the constraint. The result is that the transmission penalty factor does not set the shadow price. The details of PJM's logic and practice are not entirely clear. But in 2015, for all transmission constraints for which a penalty factor at or above $2,000 per MWh was used, 41 percent of the constraints' shadow prices were within ten percent of the penalty factor.

The MMU recommends that PJM explicitly state its policy on the use of transmission penalty factors including the level of the penalty factors, the triggers for the use of the penalty factors, the appropriate line ratings to trigger the use of penalty factors, and when the transmission penalty factors will be used to set the shadow price.

The components of LMP are shown in Table 3-68, including markup using unadjusted cost offers.[69] Table 3-68 shows that for the first six months of 2016, 53.0 percent of the load-weighted LMP was the result of coal costs, 21.5 percent was the result of gas costs and 2.17 percent was the result of the cost of emission allowances. Using adjusted cost offers, markup was 3.6 percent of the load-weighted LMP. The fuel-related components of LMP reflect the degree to which the cost of the identified fuel affects LMP and does not reflect the other components of the offers of units burning that fuel. The component

69 These components are explained in the *Technical Reference for PJM Markets*, at "Calculation and Use of Generator Sensitivity/Unit Participation Factors."

NA is the unexplained portion of load-weighted LMP. Occasionally, PJM fails to provide all the data needed to accurately calculate generator sensitivity factors. As a result, the LMP for those intervals cannot be decomposed into component costs. The cumulative effect of excluding those five-minute intervals is the component NA. In the first six months of 2016, nearly ten percent of all five-minute intervals had insufficient data. The percent column is the difference in the proportion of LMP represented by each component between the first six months of 2016 and the first six months of 2015.

Table 3-68 Components of PJM real-time (Unadjusted), load-weighted, average LMP: January through June, 2015 and 2016

	2015 (Jan-Jun)		2016 (Jan-Jun)		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change Percent
Coal	$17.24	40.8%	$14.34	53.0%	12.2%
Gas	$12.66	29.9%	$5.83	21.5%	(8.4%)
Ten Percent Adder	$3.53	8.3%	$2.33	8.6%	0.3%
VOM	$2.64	6.2%	$2.12	7.8%	1.6%
NA	$0.86	2.0%	$1.16	4.3%	2.3%
NO_x Cost	$0.03	0.1%	$0.50	1.8%	1.8%
LPA Rounding Difference	$0.78	1.8%	$0.34	1.3%	(0.6%)
Ancillary Service Redispatch Cost	$1.32	3.1%	$0.30	1.1%	(2.0%)
Oil	$2.30	5.4%	$0.28	1.1%	(4.4%)
Increase Generation Adder	$0.36	0.8%	$0.27	1.0%	0.2%
Other	$0.06	0.1%	$0.13	0.5%	0.3%
SO_2 Cost	$0.01	0.0%	$0.09	0.3%	0.3%
Market-to-Market Adder	$0.01	0.0%	$0.01	0.0%	0.0%
Uranium	($0.00)	(0.0%)	$0.00	0.0%	0.0%
Municipal Waste	$0.02	0.0%	$0.00	0.0%	(0.0%)
FMU Adder	$0.00	0.0%	$0.00	0.0%	(0.0%)
CO_2 Cost	$0.26	0.6%	$0.00	0.0%	(0.6%)
Constraint Violation Adder	($0.00)	(0.0%)	$0.00	0.0%	0.0%
LPA-SCED Differential	($0.08)	(0.2%)	($0.01)	(0.0%)	0.2%
Decrease Generation Adder	($0.08)	(0.2%)	($0.03)	(0.1%)	0.1%
Wind	($0.07)	(0.2%)	($0.06)	(0.2%)	(0.1%)
Markup	$0.46	1.1%	($0.53)	(1.9%)	(3.0%)
Total	$42.30	100.0%	$27.09	100.0%	0.0%

In order to accurately assess the markup behavior of market participants, real-time and day-ahead LMPs are decomposed using two different approaches. In the first approach, (Table 3-68 and Table 3-73) markup is simply the difference between the price offer and the cost offer. In the second approach, (Table 3-69 and Table 3-74) the 10 percent markup is removed from the cost offers of coal units.

The components of LMP are shown in Table 3-69, including markup using adjusted cost offers.

Table 3-69 Components of PJM real-time (Adjusted), load-weighted, average LMP: January through June, 2015 and 2016

	2015 (Jan-Jun)		2016 (Jan-Jun)		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change Percent
Coal	$17.24	40.8%	$14.34	53.0%	12.2%
Gas	$12.66	29.9%	$5.83	21.5%	(8.4%)
VOM	$2.64	6.2%	$2.12	7.8%	1.6%
NA	$0.86	2.0%	$1.16	4.3%	2.3%
Markup	$2.20	5.2%	$0.97	3.6%	(1.6%)
Ten Percent Adder	$1.79	4.2%	$0.83	3.1%	(1.1%)
NO_x Cost	$0.03	0.1%	$0.50	1.8%	1.8%
LPA Rounding Difference	$0.78	1.8%	$0.34	1.3%	(0.6%)
Ancillary Service Redispatch Cost	$1.32	3.1%	$0.30	1.1%	(2.0%)
Oil	$2.30	5.4%	$0.28	1.1%	(4.4%)
Increase Generation Adder	$0.36	0.8%	$0.27	1.0%	0.2%
Other	$0.06	0.1%	$0.13	0.5%	0.3%
SO_2 Cost	$0.01	0.0%	$0.09	0.3%	0.3%
Market-to-Market Adder	$0.01	0.0%	$0.01	0.0%	0.0%
Uranium	($0.00)	(0.0%)	$0.00	0.0%	0.0%
FMU Adder	$0.00	0.0%	$0.00	0.0%	(0.0%)
Municipal Waste	$0.02	0.0%	$0.00	0.0%	(0.0%)
CO_2 Cost	$0.26	0.6%	$0.00	0.0%	(0.6%)
Constraint Violation Adder	($0.00)	(0.0%)	$0.00	0.0%	0.0%
LPA-SCED Differential	($0.08)	(0.2%)	($0.01)	(0.0%)	0.2%
Decrease Generation Adder	($0.08)	(0.2%)	($0.03)	(0.1%)	0.1%
Wind	($0.07)	(0.2%)	($0.06)	(0.2%)	(0.1%)
Total	$42.30	100.0%	$27.09	100.0%	0.0%

Day-Ahead LMP

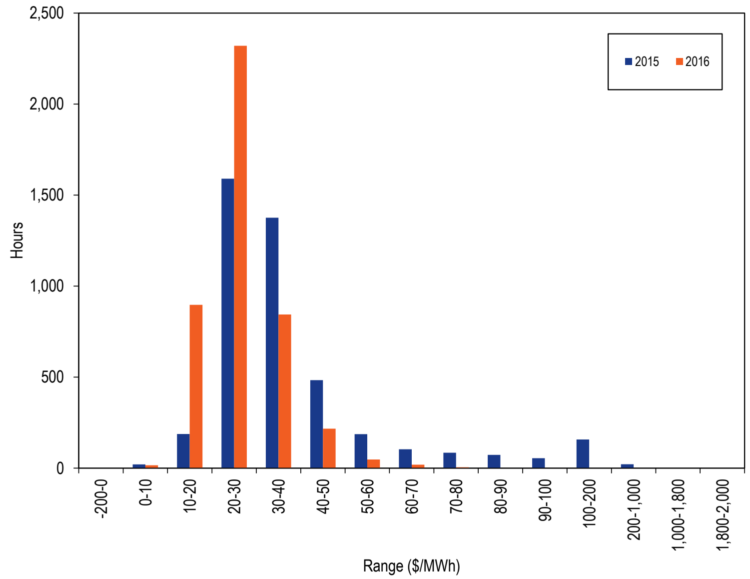
Day-ahead average LMP is the hourly average LMP for the PJM Day-Ahead Energy Market.[70]

Day-Ahead Average LMP

PJM Day-Ahead Average LMP Duration

Figure 3-39 shows the hourly distribution of PJM day-ahead average LMP for the first six months of 2015 and 2016.

Figure 3-39 Average LMP for the PJM Day-Ahead Energy Market: January through June, 2015 and 2016



70 See the *MMU Technical Reference for the PJM Markets*, at "Calculating Locational Marginal Price" for a detailed definition of Day-Ahead LMP. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

PJM Day-Ahead, Average LMP

Table 3-70 shows the PJM day-ahead, average LMP for the first six months of each year of the 16-year period 2001 through 2016.

Table 3-70 PJM day-ahead, average LMP (Dollars per MWh): January through June, 2001 through 2016

	Day-Ahead LMP			Year-to-Year Change		
Jan-Jun	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2001	$35.02	$31.34	$17.43	NA	NA	NA
2002	$24.76	$21.28	$12.49	(29.3%)	(32.1%)	(28.4%)
2003	$42.83	$39.18	$23.52	73.0%	84.1%	88.3%
2004	$44.02	$43.14	$18.33	2.8%	10.1%	(22.0%)
2005	$45.63	$42.51	$18.35	3.7%	(1.5%)	0.1%
2006	$48.33	$47.07	$16.02	5.9%	10.7%	(12.7%)
2007	$53.03	$51.08	$22.91	9.7%	8.5%	43.0%
2008	$70.12	$66.09	$31.98	32.2%	29.4%	39.6%
2009	$40.01	$37.46	$15.38	(42.9%)	(43.3%)	(51.9%)
2010	$43.81	$40.64	$15.66	9.5%	8.5%	1.8%
2011	$44.75	$40.85	$19.53	2.1%	0.5%	24.8%
2012	$30.44	$29.64	$11.77	(32.0%)	(27.4%)	(39.8%)
2013	$37.11	$35.19	$10.42	21.9%	18.7%	(11.4%)
2014	$63.52	$44.42	$69.93	71.2%	26.2%	571.1%
2015	$39.98	$31.93	$28.76	(37.1%)	(28.1%)	(58.9%)
2016	$26.24	$24.95	$8.54	(34.4%)	(21.9%)	(70.3%)

Day-Ahead, Load-Weighted, Average LMP

Day-ahead, load-weighted LMP reflects the average LMP paid for day-ahead MWh. Day-ahead, load-weighted LMP is the average of PJM day-ahead hourly LMP, each weighted by the PJM total cleared day-ahead hourly load, including day-ahead fixed load, price-sensitive load, decrement bids and up to congestion.

PJM Day-Ahead, Load-Weighted, Average LMP

Table 3-71 shows the PJM day-ahead, load-weighted, average LMP for the first six months of each year of the 16-year period 2001 through 2016.

Table 3-71 PJM day-ahead, load-weighted, average LMP (Dollars per MWh): January through June, 2001 through 2016

	Day-Ahead, Load-Weighted, Average LMP			Year-to-Year Change		
Jan-Jun	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2001	$37.08	$33.91	$18.11	NA	NA	NA
2002	$26.88	$23.00	$14.36	(27.5%)	(32.2%)	(20.7%)
2003	$45.62	$42.01	$23.96	69.8%	82.6%	66.8%
2004	$46.12	$45.45	$18.62	1.1%	8.2%	(22.3%)
2005	$48.12	$44.88	$19.24	4.3%	(1.3%)	3.3%
2006	$50.21	$48.67	$16.23	4.3%	8.5%	(15.7%)
2007	$55.70	$54.26	$23.47	10.9%	11.5%	44.7%
2008	$73.71	$69.33	$33.95	32.3%	27.8%	44.7%
2009	$42.21	$38.83	$16.16	(42.7%)	(44.0%)	(52.4%)
2010	$46.12	$42.50	$16.54	9.3%	9.5%	2.3%
2011	$47.12	$42.58	$22.34	2.2%	0.2%	35.1%
2012	$31.84	$30.35	$13.94	(32.4%)	(28.7%)	(37.6%)
2013	$38.23	$36.19	$11.03	20.1%	19.3%	(20.8%)
2014	$70.67	$47.04	$79.85	84.8%	30.0%	623.8%
2015	$43.26	$33.45	$32.23	(38.8%)	(28.9%)	(59.6%)
2016	$27.33	$25.92	$8.89	(36.8%)	(22.5%)	(72.4%)

Table 3-72 shows zonal day-ahead, and day-ahead, load-weighted, average LMP for the first six months of 2015 and 2016.

Table 3-72 Zone day-ahead and day-ahead, load-weighted, average LMP (Dollars per MWh): January through June, 2015 and 2016

	Day-Ahead Average LMP			Day-Ahead, Load-Weighted, Average LMP		
Zone	2015 (Jan-Jun)	2016 (Jan-Jun)	Percent Change	2015 (Jan-Jun)	2016 (Jan-Jun)	Percent Change
AECO	$43.23	$23.49	(45.7%)	$46.67	$24.72	(47.0%)
AEP	$35.88	$26.19	(27.0%)	$38.25	$27.11	(29.1%)
AP	$40.88	$27.08	(33.8%)	$44.58	$28.18	(36.8%)
ATSI	$36.69	$26.28	(28.4%)	$38.48	$27.13	(29.5%)
BGE	$50.31	$34.77	(30.9%)	$55.75	$37.07	(33.5%)
ComEd	$29.61	$23.73	(19.9%)	$31.09	$24.62	(20.8%)
Day	$35.71	$26.30	(26.3%)	$37.90	$27.18	(28.3%)
DEOK	$34.77	$25.74	(26.0%)	$37.03	$26.69	(27.9%)
DLCO	$33.86	$25.74	(24.0%)	$35.40	$26.61	(24.8%)
Dominion	$46.14	$29.73	(35.6%)	$52.25	$31.56	(39.6%)
DPL	$47.23	$26.82	(43.2%)	$53.99	$28.75	(46.8%)
EKPC	$33.43	$25.35	(24.2%)	$36.96	$26.46	(28.4%)
JCPL	$43.33	$22.68	(47.7%)	$47.29	$23.83	(49.6%)
Met-Ed	$42.15	$22.70	(46.1%)	$45.90	$23.63	(48.5%)
PECO	$42.44	$22.15	(47.8%)	$46.26	$23.15	(50.0%)
PENELEC	$39.98	$25.09	(37.3%)	$42.42	$25.94	(38.9%)
Pepco	$47.78	$31.59	(33.9%)	$52.22	$33.25	(36.3%)
PPL	$42.26	$22.70	(46.3%)	$47.17	$23.67	(49.8%)
PSEG	$45.42	$23.42	(48.4%)	$48.87	$24.51	(49.9%)
RECO	$45.64	$23.30	(49.0%)	$48.71	$24.39	(49.9%)
PJM	$39.98	$26.24	(34.4%)	$43.26	$27.33	(36.8%)

PJM Day-Ahead, Monthly, Load-Weighted, Average LMP

Figure 3-40 shows the PJM day-ahead, monthly and annual, load-weighted LMP from June 2000 through June 2016.[71] The PJM day-ahead monthly load-weighted average LMP in May 2016 was $24.32, which is the lowest day-ahead monthly load-weighted average since May 2002 at $23.74.

71 Since the Day-Ahead Energy Market did not start until June 1, 2000, the day-ahead data for 2000 only includes data for the last six months of that year.

Figure 3-40 Day-ahead, monthly and annual, load-weighted, average LMP: June 2000 through June 2016

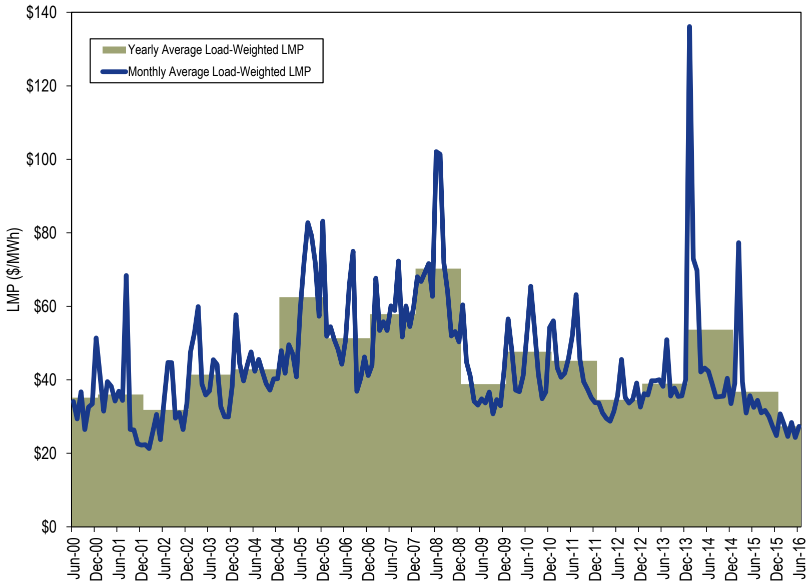
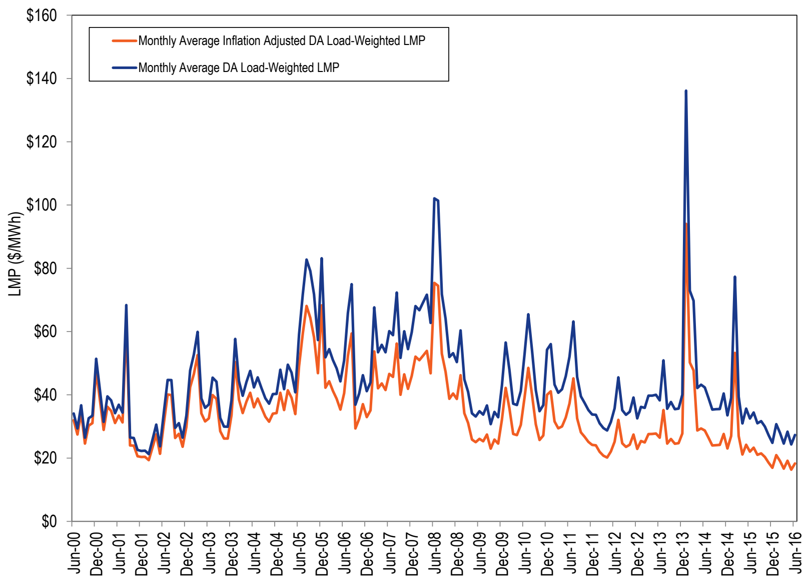


Figure 3-41 PJM Day-Ahead, monthly, load-weighted, average LMP and Day-Ahead, monthly inflation adjusted load-weighted, average LMP: June 2000 through June 2016



PJM Day-Ahead, Monthly, Inflation Adjusted Load-Weighted, Average LMP

Figure 3-43 shows the PJM day-ahead monthly load-weighted average LMP and inflation adjusted monthly day-ahead load-weighted average LMP for June 2000 through June 2016.[72] The PJM day-ahead inflation adjusted monthly load-weighted average LMP in May 2016 was $16.36, which is the lowest day-ahead monthly load-weighted average real LMP observed since PJM day-ahead markets started in 2000.

Components of Day-Ahead, Load-Weighted LMP

LMPs result from the operation of a market based on security-constrained, least-cost dispatch in which marginal resources determine system LMPs, based on their offers. For physical units, those offers can be decomposed into their components including fuel costs, emission costs, variable operation and maintenance costs, markup, FMU adder, day-ahead scheduling reserve (DASR) adder and the 10 percent cost offer adder. INC offers, DEC bids and up to congestion transactions are dispatchable injections and withdrawals in the Day-Ahead Energy Market with an offer price that cannot be decomposed. Using identified marginal resource offers and the components of unit offers, it is possible to decompose PJM system LMP using the components of unit offers and sensitivity factors.

72 To obtain the inflation adjusted monthly load-weighted average LMP, the PJM system-wide load-weighted average LMP is deflated using US Consumer Price Index for all items, Urban Consumers (base period: January 1998), published by *Bureau of Labor Statistics*. <http://download.bls.gov/pub/time.series/cu/cu.data.1.AllItems>.(July 15, 2016).

Cost offers of marginal units are separated into their component parts. The fuel related component is based on unit specific heat rates and spot fuel prices. Emission costs are calculated using spot prices for NO_X, SO_2 and CO_2 emission credits, emission rates for NO_X, emission rates for SO_2 and emission rates for CO_2. CO_2 emission costs are applicable to PJM units in the PJM states that participate in RGGI: Delaware and Maryland.[73] Day-ahead scheduling reserve (DASR) lost opportunity cost (LOC) and DASR offer adders are the calculated contribution to LMP when redispatch of resources is needed in order to satisfy DASR requirements. The FMU adder is the calculated contribution of the FMU and AU adders to LMP that results when units with FMU or AU adders are marginal cost. Table 3-73 shows the components of the PJM day-ahead, annual, load-weighted average LMP. In the first six months of 2016, 29.8 percent of the load-weighted LMP was the result of coal cost, 13.6 percent of the load-weighted LMP was the result of gas cost, 4.4 percent was the result of the up to congestion transaction cost, 22.6 percent was the result of DEC bid cost and 14.5 percent was the result of INC bid cost.

Table 3-73 Components of PJM day-ahead, (unadjusted), load-weighted, average LMP (Dollars per MWh): January through June, 2015 and 2016

	2015 (Jan - Jun)		2016 (Jan - Jun)		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change Percent
Coal	$12.72	29.4%	$8.15	29.8%	0.4%
DEC	$8.83	20.4%	$6.19	22.6%	2.2%
INC	$4.91	11.4%	$3.95	14.5%	3.1%
Gas	$6.56	15.2%	$3.72	13.6%	(1.5%)
Ten Percent Cost Adder	$2.25	5.2%	$1.38	5.1%	(0.1%)
Up to Congestion Transaction	$2.30	5.3%	$1.20	4.4%	(0.9%)
VOM	$1.62	3.7%	$1.15	4.2%	0.5%
Oil	$1.50	3.5%	$0.46	1.7%	(1.8%)
Dispatchable Transaction	$1.55	3.6%	$0.39	1.4%	(2.2%)
Markup	$0.09	0.2%	$0.38	1.4%	1.2%
NO_x	$0.01	0.0%	$0.27	1.0%	1.0%
SO_2	$0.01	0.0%	$0.05	0.2%	0.2%
DASR LOC Adder	$0.29	0.7%	$0.01	0.1%	(0.6%)
Municipal Waste	$0.01	0.0%	$0.01	0.0%	0.0%
Uranium	$0.00	0.0%	$0.01	0.0%	0.0%
Other	($0.01)	(0.0%)	$0.01	0.0%	0.0%
Nuclear	$0.00	0.0%	$0.00	0.0%	0.0%
DASR Offer Adder	$0.23	0.5%	$0.00	0.0%	(0.5%)
Constrained Off	($0.00)	(0.0%)	$0.00	0.0%	0.0%
CO_2	$0.13	0.3%	$0.00	0.0%	(0.3%)
Price Sensitive Demand	$0.06	0.1%	$0.00	0.0%	(0.1%)
Total	$43.06	99.6%	$27.33	100.0%	0.4%

Table 3-74 shows the components of the PJM day-ahead, annual, load-weighted average LMP including the adjusted markup calculated by excluding the 10 percent adder from the coal units.

73 New Jersey withdrew from RGGI, effective January 1, 2012.

Table 3-74 Components of PJM day-ahead, (adjusted), load-weighted, average LMP (Dollars per MWh): January through June, 2015 and 2016

	2015 (Jan - Jun)		2016 (Jan - Jun)		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change Percent
Coal	$12.72	29.4%	$8.15	29.8%	0.4%
DEC	$8.83	20.4%	$6.19	22.6%	2.2%
INC	$4.91	11.4%	$3.95	14.5%	3.1%
Gas	$6.56	15.2%	$3.72	13.6%	(1.5%)
Markup	$1.09	2.5%	$1.29	4.7%	2.2%
Up to Congestion Transaction	$2.30	5.3%	$1.20	4.4%	(0.9%)
VOM	$1.62	3.7%	$1.15	4.2%	0.5%
Ten Percent Cost Adder	$1.25	2.9%	$0.47	1.7%	(1.2%)
Oil	$1.50	3.5%	$0.46	1.7%	(1.8%)
Dispatchable Transaction	$1.55	3.6%	$0.39	1.4%	(2.2%)
NO_x	$0.01	0.0%	$0.27	1.0%	1.0%
SO_2	$0.01	0.0%	$0.05	0.2%	0.2%
DASR LOC Adder	$0.29	0.7%	$0.01	0.1%	(0.6%)
Municipal Waste	$0.01	0.0%	$0.01	0.0%	0.0%
Uranium	$0.00	0.0%	$0.01	0.0%	0.0%
Other	($0.01)	(0.0%)	$0.01	0.0%	0.0%
Nuclear	$0.00	0.0%	$0.00	0.0%	0.0%
DASR Offer Adder	$0.23	0.5%	$0.00	0.0%	(0.5%)
Constrained Off	($0.00)	(0.0%)	$0.00	0.0%	0.0%
CO_2	$0.13	0.3%	$0.00	0.0%	(0.3%)
Price Sensitive Demand	$0.06	0.1%	$0.00	0.0%	(0.1%)
Total	$43.06	99.6%	$27.33	100.0%	0.4%

Price Convergence

The introduction of the PJM Day-Ahead Energy Market created the possibility that competition, exercised through the use of virtual offers and bids, would tend to cause prices in the Day-Ahead and Real-Time Energy Markets to converge. Convergence is not the goal of virtual trading, but it is a possible outcome. The degree of convergence, by itself, is not a measure of the competitiveness or effectiveness of the Day-Ahead Energy Market. Price convergence does not necessarily mean a zero or even a very small difference in prices between Day-Ahead and Real-Time Energy Markets. There may be factors, from operating reserve charges to differences in risk that result in a competitive, market-based differential. In addition, convergence in the sense that day-ahead and real-time prices are equal at individual buses or aggregates on a day to day basis is not a realistic expectation as a result of uncertainty, lags in response time and modeling differences, such as differences in modeled contingencies and marginal loss calculations, between the Day-Ahead and Real-Time Energy Market.

Where arbitrage opportunities are created by differences between day-ahead and real-time energy market expectations, reactions by market participants may lead to more efficient market outcomes but there is no guarantee that the results of virtual bids and offers will result in more efficient market outcomes.

Where arbitrage incentives are created by systematic modeling differences, such as differences between the day-ahead and real-time modeled transmission contingencies and marginal loss calculations, virtual bids and offers cannot result in more efficient market outcomes. Such offers may be profitable but cannot change the underlying reason for the price difference. The virtual transactions will continue to profit from the activity for that reason regardless of the volume of those transactions. This is termed false arbitrage.

INCs, DECs and UTCs allow participants to profit from price differences between the Day-Ahead and Real-Time Energy Market. Absent a physical position in real time, the seller of an INC must buy energy in the Real-Time Energy Market to fulfill the financial obligation to provide energy. If the day-ahead price for energy is higher than the real-time price for energy, the INC makes a profit. Absent a physical position in real time, the buyer of a DEC must sell energy in the Real-Time Energy Market to fulfill the financial obligation to buy energy. If the day-ahead price for energy is lower than the real-time price for energy, the DEC makes a profit.

The profitability of a UTC transaction is the net of the separate profitability of the component INC and DEC. A UTC can be net profitable if the profit on one side of the UTC transaction exceeds the losses on the other side.

Table 3-75 shows the number of cleared UTC transactions, the number of profitable cleared UTCs, the number of cleared UTCs that were profitable at their source point and the number of cleared UTCs that were profitable at their sink point in the first six months of 2015 and 2016. In the first six months of 2016, 46.9 percent of all cleared UTC transactions were net profitable. Of cleared UTC transactions, 65.5 percent were profitable on the source side and 33.1 were profitable on the sink side but only 5.0 percent were profitable on both the source and sink side.

Table 3-75 Cleared UTC profitability by source and sink point: January through June, 2015 and 2016[74]

Jan-Jun	Cleared UTCs	Profitable UTCs	UTC Profitable at Source Bus	UTC Profitable at Sink Bus	Profitable UTC	Profitable Source	Profitable Sink
2015	3,855,491	2,003,608	2,584,326	1,342,246	52.0%	67.0%	34.8%
2016	10,520,973	4,939,119	6,887,744	3,483,773	46.9%	65.5%	33.1%

Figure 3-42 shows total UTC daily gross profits and losses and net profits and losses for January through June 2016.

Figure 3-42 UTC daily gross profits and losses and net profits: January through June, 2016[75]

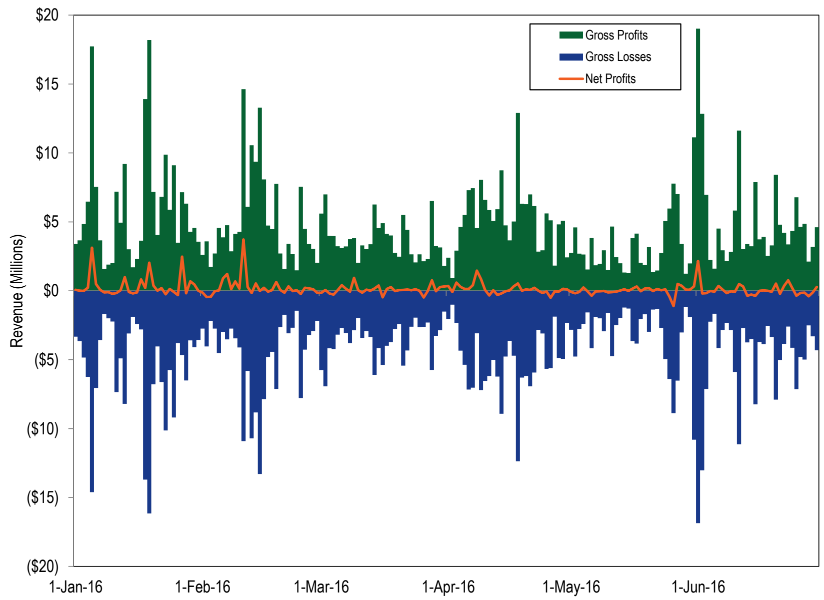


Figure 3-43 shows the cumulative UTC daily profits for January through June for the years 2013 through 2016. UTC profits during this period were primarily a result of significant unanticipated price differences between day ahead and real time LMPs. For example, the cumulative daily UTC profits for the first six months of 2014 were greater than for the other three years as a result of profits from the significant and unanticipated day ahead and real time price differences that resulted from the polar vortex conditions in January 2014. Similarly, cumulative daily UTC profits increased during late February 2015 as a result of profits from the significant day ahead and real time prices differences that resulted from cold weather conditions. The cumulative daily UTC profits for the first six months of 2016 are the lowest of these four years

74 Calculations exclude PJM administrative charges.

75 Calculations exclude PJM administrative charges.

as a result of low and stable LMPs and stable prices during the first six months of 2016.

Figure 3-43 Cumulative daily UTC profits: January through June, 2013 through 2016[76]

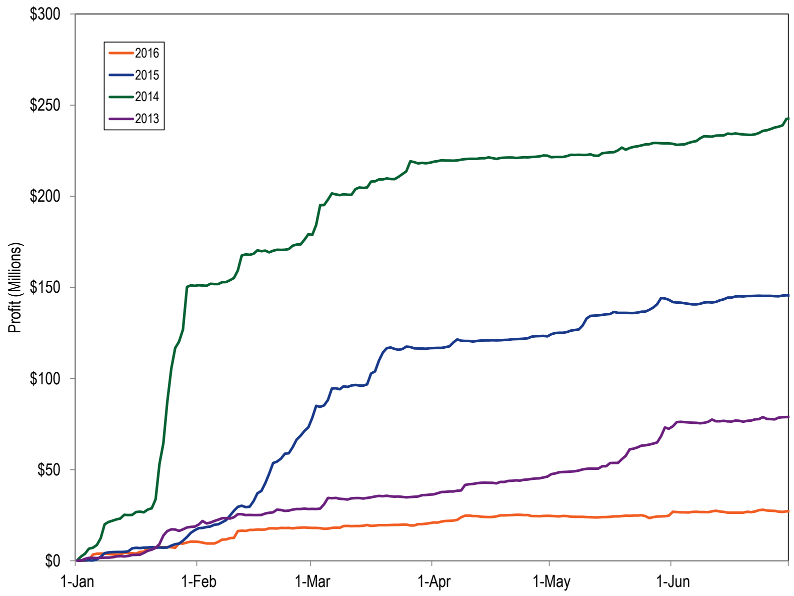


Table 3-76 shows UTC profits by month for January through June of 2013 through 2016.

76 Calculations exclude PJM administrative charges.

Table 3-76 UTC profits by month: January through June, 2013 through 2016[77]

	January	February	March	April	May	June	Total
2013	$18,773,682	$9,847,044	$7,466,482	$9,616,977	$27,433,050	$5,638,916	$78,776,151
2014	$150,903,592	$25,310,177	$41,877,547	$4,266,601	$6,654,816	$9,927,987	$238,940,721
2015	$16,766,117	$54,470,984	$45,076,093	$7,056,910	$20,587,764	$1,528,349	$145,486,216
2016	$10,517,760	$7,631,987	$2,498,271	$4,030,392	$85,273	$2,333,399	$27,097,083

There are incentives to use virtual transactions to profit from price differences between the Day-Ahead and Real-Time Energy Markets, but there is no guarantee that such activity will result in price convergence and no data to support that claim. As a general matter, virtual offers and bids are based on expectations about both day-ahead and real-time energy market conditions and reflect the uncertainty about conditions in both markets and the fact that these conditions change hourly and daily. PJM markets do not provide a mechanism that could result in immediate convergence after a change in system conditions as there is at least a one day lag after any change in system conditions before offers could reflect such changes.

Substantial virtual trading activity does not guarantee that market power cannot be exercised in the Day-Ahead Energy Market. Hourly and daily price differences between the Day-Ahead and Real-Time Energy Markets fluctuate continuously and substantially from positive to negative. There may be substantial, persistent differences between day-ahead and real-time prices even on a monthly basis (Figure 3-45).

Analysis of the data from September 1, 2013, through September 31, 2015, does not support the conclusion that UTCs contribute in any measurable way to price convergence. In addition, the sudden and significant reduction in UTC activity in September of 2014 did not cause a measurable change in price convergence.

Table 3-77 shows that the difference between the average real-time price and the average day-ahead price was -$1.11 per MWh in the first six months of 2015, and -$0.40 per MWh in the first six months of 2016. The difference between average peak real-time price and the average peak day-ahead price

77 Calculations exclude PJM administrative charges.

was -$2.75 per MWh in the first six months of 2015 and -$0.16 per MWh in the first six months of 2016.

Table 3-77 Day-ahead and real-time average LMP (Dollars per MWh): January through June, 2015 and 2016[78]

	Jan-Jun 2015				Jan-Jun 2016			
	Day-Ahead	Real-Time	Difference	Percent of Real Time	Day-Ahead	Real-Time	Difference	Percent of Real Time
Average	$39.98	$38.87	($1.11)	(2.8%)	$26.24	$25.84	($0.40)	(1.5%)
Median	$31.93	$29.04	($2.90)	(10.0%)	$24.95	$23.17	($1.78)	(7.7%)
Standard deviation	$28.76	$34.04	$5.29	15.5%	$8.54	$13.61	$5.07	37.3%
Peak average	$47.85	$45.09	($2.75)	(6.1%)	$30.19	$30.03	($0.16)	(0.5%)
Peak median	$36.74	$32.91	($3.83)	(11.6%)	$28.30	$25.46	($2.84)	(11.2%)
Peak standard deviation	$33.88	$36.39	$2.51	6.9%	$7.41	$14.78	$7.37	49.9%
Off peak average	$33.06	$33.40	$0.34	1.0%	$22.76	$22.15	($0.61)	(2.8%)
Off peak median	$27.05	$25.82	($1.23)	(4.8%)	$21.51	$20.62	($0.89)	(4.3%)
Off peak standard deviation	$21.04	$30.83	$9.79	31.7%	$7.93	$11.25	$3.32	29.5%

The price difference between the Real-Time and the Day-Ahead Energy Markets results in part, from conditions in the Real-Time Energy Market that are difficult, or impossible, to anticipate in the Day-Ahead Energy Market.

Table 3-78 shows the difference between the real-time and the day-ahead energy market prices for the first six months of each year from 2001 through 2016.

Table 3-78 Day-ahead and real-time average LMP (Dollars per MWh): January through June, 2001 through 2016

Jan-Jun	Day-Ahead	Real-Time	Difference	Percent of Real Time
2001	$35.02	$33.10	($1.92)	(5.5%)
2002	$24.76	$24.10	($0.66)	(2.7%)
2003	$42.83	$41.31	($1.53)	(3.6%)
2004	$44.02	$44.99	$0.97	2.2%
2005	$45.63	$45.71	$0.07	0.2%
2006	$48.33	$49.36	$1.03	2.1%
2007	$53.03	$55.03	$2.00	3.8%
2008	$70.12	$70.19	$0.08	0.1%
2009	$40.01	$40.12	$0.11	0.3%
2010	$43.81	$43.27	($0.54)	(1.2%)
2011	$44.75	$45.51	$0.76	1.7%
2012	$30.44	$29.74	($0.69)	(2.3%)
2013	$37.11	$36.56	($0.55)	(1.5%)
2014	$63.52	$62.14	($1.38)	(2.2%)
2015	$39.98	$38.87	($1.11)	(2.8%)
2016	$26.24	$25.84	($0.40)	(1.5%)

Table 3-79 provides frequency distributions of the differences between PJM real-time hourly LMP and PJM day-ahead hourly LMP for the first six months of 2007 through 2016.

78 The averages used are the annual average of the hourly average PJM prices for day-ahead and real-time.

Table 3-79 Frequency distribution by hours of PJM real-time LMP minus day-ahead LMP (Dollars per MWh): January through June, 2007 through 2016

	2007		2008		2009		2010		2011		2012		2013	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
< ($1,000)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($1,000) to ($750)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($750) to ($500)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($500) to ($450)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($450) to ($400)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($400) to ($350)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($350) to ($300)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($300) to ($250)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($250) to ($200)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	1	0.02%	0	0.00%
($200) to ($150)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	3	0.09%	0	0.00%
($150) to ($100)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	1	0.02%	4	0.18%	0	0.00%
($100) to ($50)	17	0.39%	62	1.42%	3	0.07%	6	0.14%	27	0.64%	8	0.37%	0	0.00%
($50) to $0	2,365	54.85%	2,578	60.45%	2,541	58.58%	2,890	66.68%	2,773	64.49%	2,940	67.69%	3,018	69.49%
$0 to $50	1,832	97.03%	1,505	94.92%	1,772	99.38%	1,366	98.13%	1,414	97.05%	1,377	99.22%	1,281	98.99%
$50 to $100	118	99.75%	195	99.38%	25	99.95%	69	99.72%	105	99.47%	25	99.79%	34	99.77%
$100 to $150	7	99.91%	23	99.91%	2	100.00%	5	99.84%	16	99.84%	5	99.91%	4	99.86%
$150 to $200	0	99.91%	2	99.95%	0	100.00%	7	100.00%	2	99.88%	2	99.95%	5	99.98%
$200 to $250	1	99.93%	1	99.98%	0	100.00%	0	100.00%	2	99.93%	0	99.95%	0	99.98%
$250 to $300	1	99.95%	0	99.98%	0	100.00%	0	100.00%	0	99.93%	1	99.98%	1	100.00%
$300 to $350	2	100.00%	1	100.00%	0	100.00%	0	100.00%	0	99.93%	1	100.00%	0	100.00%
$350 to $400	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	99.93%	0	100.00%	0	100.00%
$400 to $450	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	99.93%	0	100.00%	0	100.00%
$450 to $500	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	99.93%	0	100.00%	0	100.00%
$500 to $750	0	100.00%	0	100.00%	0	100.00%	0	100.00%	3	100.00%	0	100.00%	0	100.00%
$750 to $1,000	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
$1,000 to $1,250	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
>= $1,250	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%

Table 3-79 Frequency distribution by hours of PJM real-time LMP minus day-ahead LMP (Dollars per MWh): January through June, 2007 through 2016 (continued)

	2014		2015		2016	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
< ($1,000)	0	0.00%	0	0.00%	0	0.00%
($1,000) to ($750)	2	0.05%	0	0.00%	0	0.00%
($750) to ($500)	3	0.12%	0	0.00%	0	0.00%
($500) to ($450)	1	0.14%	0	0.00%	0	0.00%
($450) to ($400)	6	0.28%	0	0.00%	0	0.00%
($400) to ($350)	5	0.39%	0	0.00%	0	0.00%
($350) to ($300)	5	0.51%	0	0.00%	0	0.00%
($300) to ($250)	6	0.64%	0	0.00%	0	0.00%
($250) to ($200)	14	0.97%	1	0.02%	0	0.00%
($200) to ($150)	14	1.29%	4	0.12%	0	0.00%
($150) to ($100)	45	2.33%	12	0.39%	0	0.00%
($100) to ($50)	89	4.37%	50	1.54%	0	0.00%
($50) to $0	2,837	69.70%	3,020	71.08%	2,975	68.12%
$0 to $50	1,144	96.04%	1,146	97.47%	1,356	99.18%
$50 to $100	82	97.93%	74	99.17%	29	99.84%
$100 to $150	36	98.76%	28	99.82%	7	100.00%
$150 to $200	17	99.15%	6	99.95%	0	100.00%
$200 to $250	9	99.36%	1	99.98%	0	100.00%
$250 to $300	8	99.54%	1	100.00%	0	100.00%
$300 to $350	3	99.61%	0	100.00%	0	100.00%
$350 to $400	3	99.68%	0	100.00%	0	100.00%
$400 to $450	2	99.72%	0	100.00%	0	100.00%
$450 to $500	0	99.72%	0	100.00%	0	100.00%
$500 to $750	7	99.88%	0	100.00%	0	100.00%
$750 to $1,000	0	99.88%	0	100.00%	0	100.00%
$1,000 to $1,250	1	99.91%	0	100.00%	0	100.00%
>= $1,250	4	100.00%	0	100.00%	0	100.00%

Figure 3-44 shows the hourly differences between day-ahead and real-time hourly LMP in the first six months of 2016.

Figure 3-44 Real-time hourly LMP minus day-ahead hourly LMP: January through June, 2016

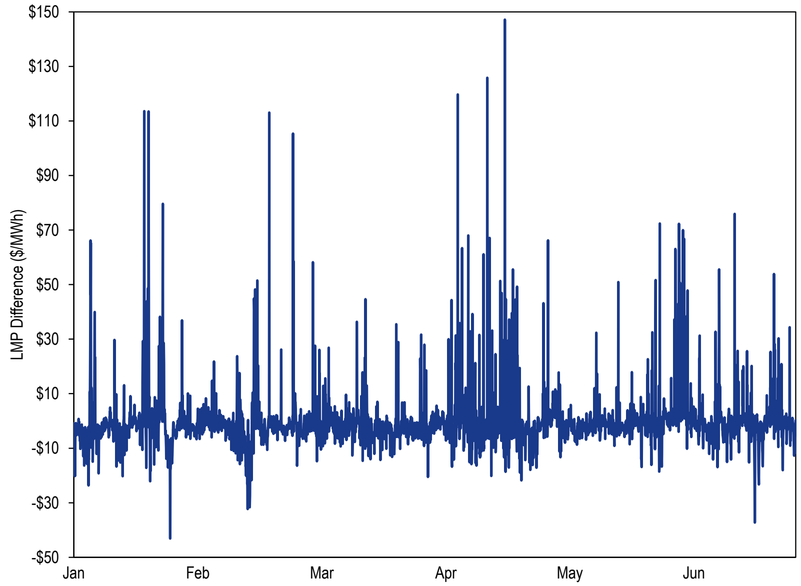


Figure 3-45 shows the monthly average of the differences between the day-ahead and real-time PJM average LMPs from January 1, 2015, through June 30, 2016.

Figure 3-45 Monthly average of real-time minus day-ahead LMP: January 2015 through June 2016

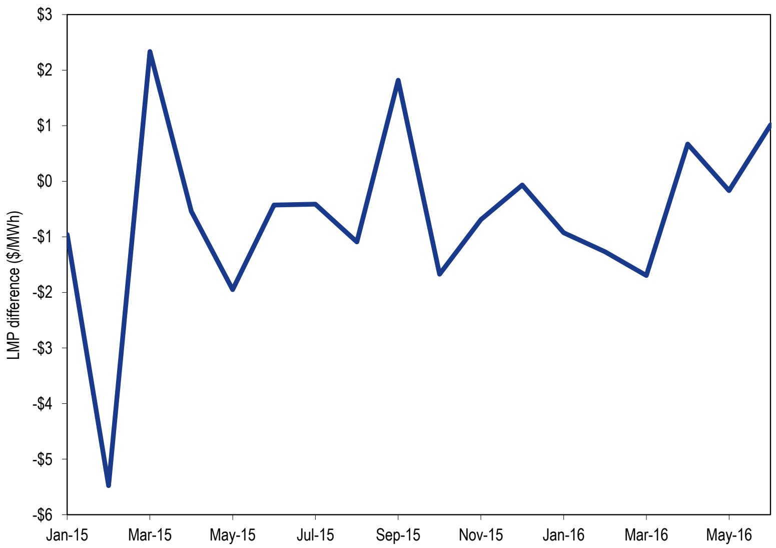


Figure 3-46 shows the monthly average of the absolute value of the differences between the day-ahead and real-time hourly, nodal LMPs from January 1, 2015, through June 30, 2016.

Figure 3-46 Monthly average of the absolute value of real-time minus day-ahead LMP by pnode: January 2015 through June 2016

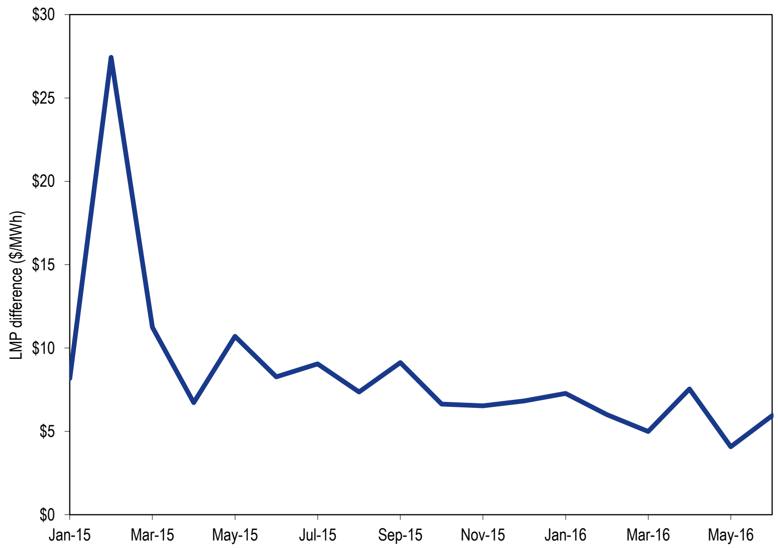
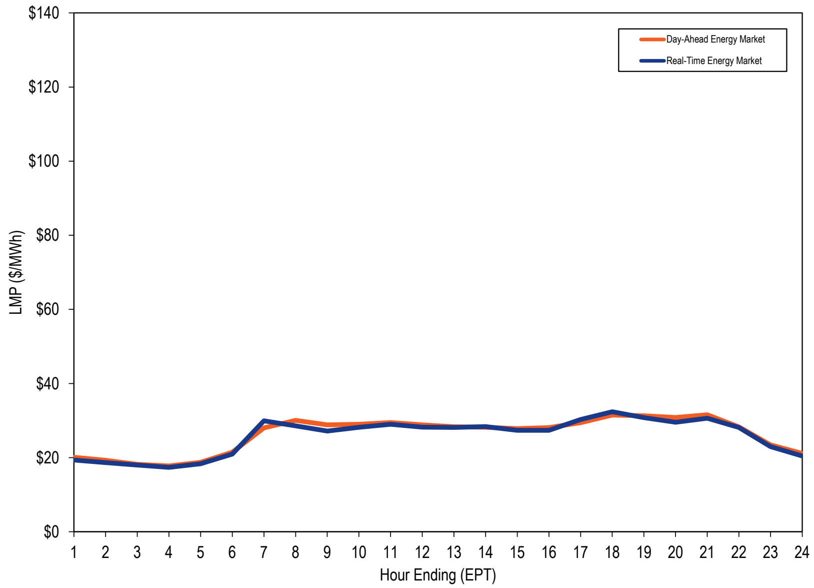


Figure 3-47 shows day-ahead and real-time LMP on an average hourly basis for the first six months of 2016.

Figure 3-47 PJM system hourly average LMP: January through June, 2016



Scarcity

PJM's Energy Market experienced no shortage pricing events in the first six months of 2016. Table 3-80 shows a summary of the number of days emergency alerts, warnings and actions were declared in PJM in the first six months of 2015 and 2016.

Table 3-80 Summary of emergency events declared: January through June, 2015 and 2016

	Number of days events declared	
Event Type	Jan - Jun, 2015	Jan - Jun, 2016
Cold Weather Alert	26	4
Hot Weather Alert	9	0
Maximum Emergency Generation Alert	0	0
Primary Reserve Alert	0	0
Voltage Reduction Alert	0	0
Primary Reserve Warning	0	0
Voltage Reduction Warning	0	0
Pre Emergency Mandatory Load Management Reduction Action	2	0
Emergency Mandatory Load Management Reduction Action (30, 60 or 120 minute lead time)	2	0
Maximum Emergency Action	1	0
Emergency Energy Bids Requested	0	0
Voltage Reduction Action	0	0
Shortage Pricing	0	0
Energy export recalls from PJM capacity resources	0	0

Emergency procedures

PJM declares alerts at least a day prior to the operating day to warn members of possible emergency actions that could be taken during the operating day. In real time on the operating day, PJM issues warnings notifying members of system conditions that could result in emergency actions during the operating day.

PJM declared cold weather alerts on four days in the first six months of 2016 compared to 26 days in the first six months of 2015.[79] The purpose of a cold weather alert is to prepare personnel and facilities for expected extreme cold weather conditions, generally when temperatures are forecast to approach minimums or fall below 10 degrees Fahrenheit.

PJM did not declare any hot weather alerts on in the first six months of 2015 and 2016.[80] The purpose of a hot weather alert is to prepare personnel and facilities for expected extreme hot and humid weather conditions, generally

79 See PJM. "Manual 13: Emergency Operations," Revision 59 (January 1, 2016), Section 3.3 Cold Weather Alert, p. 46.
80 See PJM. "Manual 13: Emergency Operations," Revision 59 (January 1, 2016), Section 3.4 Hot Weather Alert, p. 50.

when temperatures are forecast to exceed 90 degrees Fahrenheit with high humidity.

PJM did not declare any maximum emergency generation alert on in the first six months of 2015 and 2016. The purpose of a maximum emergency generation alert is to provide an alert at least one day prior to the operating day that system conditions may require use of PJM emergency actions. It is called to alert PJM members that maximum emergency generation may be requested in the operating capacity.[81] This means that if PJM directs members to load maximum emergency generation during the operating day, the resources must be able to increase generation above the maximum economic level of their offer.

PJM did not declare any primary reserve alerts in the first six months of 2016 and 2015. The purpose of a primary reserve alert is to alert members at least one day prior to the operating day that available primary reserves are anticipated to be short of the primary reserve requirement on the operating day. It is issued when the estimated primary reserves are less than the forecast primary reserve requirement.

PJM did not declare any voltage reduction alert in the first six months of 2016 and 2015. The purpose of a voltage reduction alert is to alert members at least one day prior to the operating day that a voltage reduction may be required on the operating day. It is issued when the estimated operating reserve is less than the forecast synchronized reserve requirement.

PJM did not declare any primary reserve warning in the first six months of 2016 and 2015. The purpose of a primary reserve warning is to warn members that available primary reserves are less than the primary reserve requirement but greater than the synchronized reserve requirement.

PJM did not declare any voltage reduction warnings and reductions of noncritical plant load in the first six months of 2016 and 2015. The purpose of a voltage reduction warning and reduction of noncritical plant load is to warn members that available synchronized reserves are less than the synchronized reserve requirement and that a voltage reduction may be required. It can be issued for the RTO or for specific control zones.

PJM did not declare any emergency mandatory load management reductions in the first six months of 2016, compared to two days in the first six months of 2015 in all or parts of the PJM service territory. The purpose of emergency mandatory load management is to request curtailment service providers (CSP) to implement load reductions from demand resources registered in PJM demand response programs that have a lead time of between one and two hours (long lead time) and a lead time of up to one hour (short lead time). Starting in June 2014, PJM combined the long lead and short lead emergency load management action procedures into Emergency Mandatory Load Management Reduction Action (30, 60 or 120 minute lead time). PJM dispatch declares NERC Energy Emergency Alert level 2 (EEA2) concurrent with Emergency Mandatory load Management Reductions. PJM also added a Pre-Emergency Mandatory Load Management Reduction Action (30, 60 or 120 minute lead time) step to request load reductions before declaring emergency load management reductions.

PJM did not declare any maximum emergency generation actions in the first six months of 2016 compared to one day in the first six months of 2015. The purpose of a maximum emergency generation action is to request generators to increase output to the maximum emergency level which unit owners may define at a level above the maximum economic level. A maximum emergency generation action can be issued for the RTO, for specific control zones or for parts of control zones.

PJM did not request any offers for emergency energy purchases in the first six months of 2016 and 2015.

PJM did not declare any voltage reduction actions in the first six months of 2016 and 2015. The purpose of a voltage reduction is to reduce load to provide sufficient reserves, to maintain tie flow schedules, and to preserve limited energy sources. When a voltage reduction action is issued for a reserve

81 See PJM. "Manual 13: Emergency Operations," Revision 59 (January 1, 2016), Section 2.3.1 Advance Notice Emergency Procedures: Alerts, p. 17.

zone or subzone, the primary reserve penalty factor and synchronized reserve penalty factor are incorporated into the synchronized and nonsynchronized reserve market clearing prices and locational marginal prices until the voltage reduction action has been terminated.

PJM declared six synchronized reserve events in the first six months of 2016 compared to 11 synchronized reserve events in the first six months of 2015.[82] Synchronized reserve events may occur at any time of the year due to sudden loss of generation or transmission facilities and do not necessarily coincide with capacity emergency conditions such as maximum generation emergency events or emergency load management events.

Table 3-81 provides a description of PJM declared emergency procedures.

Table 3-81 Description of emergency procedures

Emergency Procedure	Purpose
Cold Weather Alert	To prepare personnel and facilities for extreme cold weather conditions, generally when forecast weather conditions approach minimum or temperatures fall below ten degrees Fahrenheit.
Hot Weather Alert	To prepare personnel and facilities for extreme hot and/or humid weather conditions, generally when forecast temperatures exceed 90 degrees with high humidity.
Maximum Emergency Generation Alert	To provide an early alert at least one day prior to the operating day that system conditions may require the use of the PJM emergency procedures and resources must be able to increase generation above the maximum economic level of their offers.
Primary Reserve Alert	To alert members of a projected shortage of primary reserve for a future period. It is implemented when estimated primary reserve is less than the forecast requirement.
Voltage Reduction Alert	To alert members that a voltage reduction may be required during a future critical period. It is implemented when estimated reserve capacity is less than forecasted synchronized reserve requirement.
Pre-Emergency Load Management Reduction Action	To request load reductions from customers registered in the PJM Demand Response program that need 30, 60, or 120 minute lead time before declaring emergency load management reductions
Emergency Mandatory Load Management Reduction Action	To request load reductions from customers registered in the PJM Demand Response program that need 30, 60, or 120 minute lead time to provide additional load relief, generally declared simultaneously with NERC Energy Emergency Alert Level 2 (EEA2)
Primary Reserve Warning	To warn members that available primary reserve is less than required and present operations are becoming critical. It is implemented when available primary reserve is less than the primary reserve requirement but greater than the synchronized reserve requirement.
Maximum Emergency Generation Action	To provide real time notice to increase generation above the maximum economic level. It is implemented whenever generation is needed that is greater than the maximum economic level.
Voltage Reduction Warning & Reduction of Non-Critical Plant Load	To warn members that actual synchronized reserves are less than the synchronized reserve requirement and that voltage reduction may be required.
Deploy All Resources Action	For emergency events that do not evolve over time, but rather develop rapidly and without prior warning, PJM issues this action to instruct all generation resources to be online immediately and to all load management resources to reduce load immediately.
Manual Load Dump Warning	To warn members of the critical condition of present operations that may require manually dumping load. Issued when available primary reserve capacity is less than the largest operating generator or the loss of a transmission facility jeopardizes reliable operations after all other possible measures are taken to increase reserve.
Voltage Reduction Action	To reduce load to provide sufficient reserve capacity to maintain tie flow schedules and preserve limited energy sources. It is implemented when load relief is needed to maintain tie schedules.
Manual Load Dump Action	To provide load relief when all other possible means of supplying internal PJM RTO load have been used to prevent a catastrophe within the PJM RTO or to maintain tie schedules so as not to jeopardize the reliability of the other interconnected regions.

82 See *2016 Quarterly State of the Market Report for PJM*, Section 10: Ancillary Service Markets for details on the spinning events.

Table 3-82 shows the dates when emergency alerts and warnings were declared and when emergency actions were implemented in the first six months of 2016.

Table 3-82 PJM declared emergency alerts, warnings and actions: January through June, 2016

Dates	Cold Weather Alert	Maximum Emergency Generation Alert	Primary Reserve Alert	Voltage Reduction Alert	Primary Reserve Warning	Voltage Reduction Warning and Reduction of Non-Critical Plant Load	Maximum Emergency Generation Action	Pre-Emergency Mandatory Load Management Reduction	Emergency Mandatory Load Management Reduction	Voltage Reduction	Manual Load Dump Warning
1/18/2016	PJM Western Region										
1/19/2016	PJM Western Region										
2/13/2016	PJM Western Region										
2/15/2016	PJM except Dominion										

Scarcity and Scarcity Pricing

In electricity markets, scarcity means that demand, including reserve requirements, is nearing the limits of the available capacity of the system. Under the PJM rules that were in place through September 30, 2012, high prices, or scarcity pricing, resulted from high offers by individual generation owners for specific units when the system was close to its available capacity. But this was not an efficient way to manage scarcity pricing and made it difficult to distinguish between market power and scarcity pricing.

On October 1, 2012, PJM introduced a new administrative scarcity pricing regime. Under the current PJM market rules, shortage pricing conditions are triggered when there is a shortage of synchronized or primary reserves in the RTO or in the Mid-Atlantic and Dominion (MAD) Subzone. In times of reserve shortage, the value of reserves is included as a penalty factor in the optimization and in the price of energy.[83] Shortage pricing is also triggered when PJM issues a voltage reduction action or a manual load dump action for a reserve zone or a reserve subzone. When shortage pricing is triggered, the primary reserve penalty factor and the synchronized reserve penalty factor are incorporated in the calculation of the synchronized and nonsynchronized reserve market clearing prices and the locational marginal price.

83 See PJM OATT, 2.2 (d) General, (February 25, 2014), pp. 1815, 1819.

In the first six months of 2016, there were no shortage pricing events triggered in PJM.

Final Rule on Shortage Pricing and Settlement Intervals

On September 17, 2015, the Commission issued a Notice of Proposed Rulemaking (NOPR) in which the Commission proposed to address price formation issues in RTOs/ISOs ("price formation NOPR").[84] In particular, the price formation NOPR proposed (i) to require the alignment of settlement and dispatch intervals for energy and operating reserves; and (ii) to require that each RTO/ISO trigger shortage pricing for any dispatch interval during which a shortage of energy or operating reserves occurs. These proposed reforms are intended to ensure that resources have price signals that provide incentives to conform their output to dispatch instructions, and that prices reflect operating needs at each dispatch interval.[85]

On June 16, 2016, the Commission issued a Final Rule in which it required each RTO/ISO to settle energy, operating reserves and intertie transactions using the same time intervals that it uses for to dispatch units or schedule these

84 152 FERC ¶ 61,218 (September 17, 2015).
85 *Id* at P 5.

transactions.[86] In PJM, the energy market dispatch and pricing interval is five minutes, and the order requires PJM to settle energy transactions on a five minute basis. In PJM, the synchronized reserve and regulation market dispatch and pricing interval is five minutes, and the order requires PJM to settle these reserves on a five minute basis. In PJM, intertie transactions are scheduled on fifteen minute intervals, and the order requires PJM to settle intertie transactions on a fifteen minute basis. However, the Commission allowed PJM to propose a shorter time interval for settling intertie transactions.[87]

The Commission also required each RTO/ISO to trigger shortage pricing for any dispatch and pricing interval in which a shortage of energy or operating reserves is indicated by the RTO/ISO's software.[88] In PJM, the rule would require PJM to trigger shortage pricing for any five minute interval when the dispatch software indicates a shortage of synchronized reserves or primary reserves. Currently in PJM, if the dispatch tools reflect a shortage of reserves (primary or synchronized) for a time period shorter than a defined threshold (30 minutes) due to ramp limitations or unit startup delays, it is considered a transient shortage, a shortage event is not declared, and shortage pricing is not implemented. The reason for using a minimum threshold time for a reserve shortage is that the level of reserve measurement accuracy does not support a shorter time period. The rationale for including voltage reduction actions and manual load dump actions as triggers for shortage pricing is to reflect the fact that when dispatchers need to take these emergency actions to maintain reliability, the system is short reserves and prices should reflect that condition, even if the data does not show a shortage of reserves.[89]

If PJM were to move to a shortage pricing mechanism that is triggered by transient shortages, there needs to be accurate measurement of real time reserves that can support such a definition. That does not appear to be the case at present in PJM. Without very accurate measurement of reserves at minute by minute granularity, system operators cannot know with certainty that there is a shortage condition and therefore the trigger for five minute shortage pricing does not exist. The advantages of five minute shortage pricing are all implicitly based on the premise that the RTO knows accurately whether it is in a shortage condition. If PJM cannot demonstrate that it can accurately measure reserves at minute by minute granularity, it should not implement or continue five minute shortage pricing until it can demonstrate that capability.[90] The Commission directed in the Final Rule that, to the extent an RTO/ISO needs to enhance its measurement capabilities to implement the shortage pricing requirement, it should propose to do so in its compliance filing.[91]

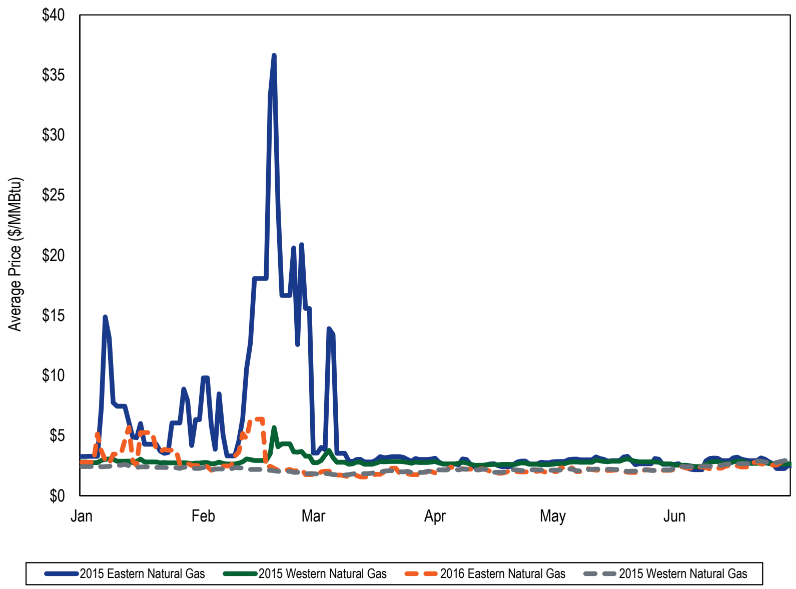
PJM Cold Weather Operations 2016

Natural gas supply and prices

As of January 1, 2016, gas fired generation was 34 percent (60,487.4 MW) of the total installed PJM capacity (177,682.8 MW).[92] The extreme cold weather conditions and the associated high demand for natural gas led to supply constraints on the gas transmission system which resulted in natural gas price volatility and interruptions to customers without firm transportation. Figure 3-48 shows the average daily price of delivered natural gas for eastern and western parts of PJM service territory in the first six months of 2016 and 2015.[93]

86 155 FERC ¶ 61,276 (June 16, 2016).
87 *Id* at P 90.
88 *Id* at P 162.
89 *See*, e.g., Scarcity and Shortage Pricing, Offer Mitigation and Offer Caps Workshop, Docket No. AD14-14-000, Transcript 29:21- 30:14 (Oct. 28, 2014)
90 *See* Comments of the Independent Market Monitor for PJM, Docket No. RM15-24-000 (December 1, 2015) at 9.
91 155 FERC ¶ 61,276 at P 177 (June 16, 2016).
92 *2016 Quarterly State of the Market Report for PJM: January through March*, Section 5: Capacity Market, at Installed Capacity.
93 Eastern natural gas consists of the average of Texas Eastern M3, Transco Zone 6 non-NY, Transco Zone 6 NY and Transco Zone 5 daily fuel price indices. Western natural gas prices are the average of Dominion North Point, Columbia Appalachia and Chicago City gate daily fuel price indices.

Figure 3-48 Average daily delivered price for natural gas: January through June, 2015 and 2016 ($/MMBtu)



During the first three months of 2015 and 2016, a number of interstate gas pipelines that supply fuel for generators in the PJM service territory issued restriction notices limiting the availability of nonfirm transportation services. These notices include warnings of operational flow orders (OFO) and actual OFOs. OFOs may restrict the provision of gas to 24 hour ratable takes which means that hourly nominations must be the same for each of the 24 hours in the day, with penalties for deviating from the nominated quantities. Pipelines may also enforce strict balancing constraints which limit the ability of gas users (without no notice service or storage service) to deviate from the 24 hour ratable take and which limit the ability of users to have access to unused gas.

Pipeline operators use restrictive and inflexible rules to manage the balance of supply and demand during extreme operating conditions. The independent operations of geographically overlapping pipelines during extreme conditions highlights the potential shortcomings of a gas pipeline network that relies on individual pipelines to manage the balancing of supply and demand. The independent operational restrictions imposed by pipelines and the impact on electric generators during extreme conditions suggests there may be potential benefits to creating an ISO/RTO structure to coordinate the supply of gas across pipelines and with the electric RTOs, or the creation of a gas supply coordination framework under existing electric ISO/RTOs.