2008 State of the Market Report for PJM

Volume 2: Detailed Analysis

Monitoring Analytics, LLC
Independent Market Monitor for PJM

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PREFACE

Attachment M (PJM Market Monitoring Plan) to the PJM Open Access Transition Tariff provides:

> The Market Monitoring Unit shall prepare and submit contemporaneously to the Commission, the State Commissions, the PJM Board, PJM Management and to the PJM Members Committee, annual state-of-the-market reports on the state of competition within, and the efficiency of, the PJM Markets. In such reports, the Market Monitoring Unit may make recommendations regarding any matter within its purview. These reports shall address, among other things, the extent to which prices in the PJM Markets reflect competitive outcomes, the structural competitiveness of the PJM Markets, the effectiveness of bid mitigation rules, and the effectiveness of the PJM Markets in signaling infrastructure investment. These reports shall include recommendations as to whether changes to the Market Monitoring Unit or the Plan are required.[1]

Accordingly, Monitoring Analytics, LLC, which serves as the Market Monitoring Unit defined in Attachment M, submits this *2008 State of the Market Report*, the eleventh such annual report.

1 PJM, OATT, "Attachment M: PJM Market Monitoring Plan," Fourth Revised Sheet No. 452 (Effective August 1, 2008).

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SECTION 1 – INTRODUCTION

The PJM Interconnection, L.L.C. operates a centrally dispatched, competitive wholesale electric power market that, as of December 31, 2008, had installed generating capacity of 164,895 megawatts (MW) and more than 500 market buyers, sellers and traders of electricity in a region including more than 51 million people in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.[1] As part of that function, PJM coordinates and directs the operation of the transmission grid and plans transmission expansion improvements to maintain grid reliability in this region.

PJM Market Background

PJM operates the Day-Ahead Energy Market, the Real-Time Energy Market, the Reliability Pricing Model (RPM) Capacity Market, the Regulation Market, the Synchronized Reserve Markets, the Day Ahead Scheduling Reserve (DASR) Market and the Long Term, Annual and Monthly Balance of Planning Period Auction Markets in Financial Transmission Rights (FTRs).

PJM introduced energy pricing with cost-based offers and market-clearing nodal prices on April 1, 1998, and market-clearing nodal prices with market-based offers on April 1, 1999. PJM introduced the Daily Capacity Market on January 1, 1999, and the Monthly and Multimonthly Capacity Markets in mid-1999. PJM implemented an auction-based FTR Market on May 1, 1999. PJM implemented the Day-Ahead Energy Market and the Regulation Market on June 1, 2000. PJM modified the regulation market design and added a market in spinning reserve on December 1, 2002. PJM introduced an Auction Revenue Rights (ARR) allocation process and an associated Annual FTR Auction effective June 1, 2003. PJM introduced the RPM Capacity Market effective June 1, 2007. PJM implemented the DASR Market on June 1, 2008. [2]

Volume I of the *2008 State of the Market Report* is the Introduction. More detailed analysis and results are included in Volume II.[3]

1 See the *2008 State of the Market Report*, Volume II, Appendix A, "PJM Geography" for maps showing the PJM footprint and its evolution.

2 See also the *2008 State of the Market Report*, Volume II, Appendix B, "PJM Market Milestones."

3 Analysis of 2008 market results requires comparison to prior years. During calendar years 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. 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 integrations, their timing and their impact on the footprint of the PJM service territory, see the *2008 State of the Market Report*, Volume II, Appendix A, "PJM Geography."

Conclusions

This report assesses the competitiveness of the markets managed by PJM during 2008, including market structure, participant behavior and market performance. This report was prepared by and represents the analysis of the independent Market Monitoring Unit (MMU) for PJM.

The MMU concludes that in 2008:

- The Energy Market results were competitive;
- The Capacity Market results were competitive;
- The Regulation Market results cannot be determined to have been competitive or to have been noncompetitive;
- The Synchronized Reserve Markets' results were competitive;
- The Day Ahead Scheduling Reserve Market results were competitive; and
- The FTR Auction Market results were competitive.

Recommendations

The MMU recommends retention of key market rules, specific enhancements to those rules and implementation of new rules that are required for continued competitive results in PJM markets and for continued improvements in the functioning of PJM markets. The recommendations are for continued action where PJM has already identified areas for improvement and for new action in areas where PJM has not yet identified a plan.

Continued Action

- Retention and application of the improved local market power mitigation rules to prevent the exercise of local market power in the Energy Market while ensuring appropriate economic signals when investment is required.

  PJM applies the three pivotal supplier test to determine whether local energy markets are structurally competitive. The three pivotal supplier test, as implemented, is consistent with the United States Federal Energy Regulatory Commission's (FERC's) market power tests, encompassed under the delivered price test. The test is a flexible, targeted real-time measure of market structure which replaced the previous mitigation method of offer capping of all units required to relieve a constraint. The application of the three pivotal supplier test successfully limits offer capping in the Energy Market to situations where the local market is structurally noncompetitive and where specific owners have structural market power.

- Retention, application and improvement of the RPM rules included in PJM's Tariff to stimulate competition, to provide direct incentives for performance, to provide locational price signals, to provide forward auctions to permit competition from new entrants and to limit market power by the application of clear and explicit market power mitigation rules. Implementation of enhancements to incentives for capacity resource performance to ensure stronger, market-based incentives for actual performance when needed.

Market power remains a serious concern in the PJM Capacity Market based on market structure conditions in this market including high levels of supplier concentration, frequent occurrences of pivotal suppliers and extreme inelasticity of demand. The RPM Capacity Market design explicitly allows competitive prices to reflect local scarcity without relying on the exercise of market power to achieve the objectives of the Capacity Market design and explicitly limits the exercise of market power via the application of the three pivotal supplier test. RPM rules could be improved by ensuring that capacity payments are made only to units that perform, that the must offer requirement does not permit either physical or economic withholding, that the requirement for capacity resources to make offers in the Day-Ahead Energy Market explicitly require competitive offers and that locational price separation is determined by market fundamentals rather than by rule.

- Retention and application of the improved market power mitigation rules in the Regulation Market to prevent the exercise of market power in the Regulation Market while ensuring appropriate economic signals when investment is required and an efficient market mechanism.

  In December 2008, PJM implemented the three pivotal supplier test in the Regulation Market, which is expected to successfully address market power issues. The PJM Regulation Market continues to be characterized by structural market power. PJM's application of targeted, flexible, real-time, market power mitigation in the Regulation Market addresses only the hours in which structural market power exists and therefore provides an incentive for the continued development of competition.

- Retention of the $1,000 per MWh offer cap in the PJM Energy Market and other rules that limit incentives to exercise market power.

  The PJM market design includes a variety of rules that effectively limit the incentive to exercise market power and ensure competitive outcomes. These should be retained and enforced and any proposed PJM market rule change should be evaluated for its impact on competitive outcomes.

- Retention and application of enhancements to rules governing the payment of operating reserve credits to generators and the allocation of operating reserves charges among market participants.

  The operating reserve rules should ensure that credits and corresponding charges to market participants are consistent with incentives for efficient market outcomes and should reduce gaming incentives. The rules should ensure that market power cannot be exercised to increase operating reserve credits through the use of artificially restrictive unit operating parameters. The rules should base the payment of credits on operating parameters determined by the physical limits of units rather than by offers.

  PJM implemented changes to the operating reserve rules on December 1, 2008. The new operating reserve rules represent positive steps towards the goals of removing the ability to exercise market power and refining the allocation of operating reserves charges to better reflect causal factors.

- Modification of rules governing demand-side programs to ensure appropriate levels of payment and to ensure appropriate measurement and verification of demand-side response. Evaluation of additional actions to address institutional issues which may inhibit the evolution of demand-side price response.

  PJM and the MMU should continue efforts to ensure that market power is not exercised on the demand side of the market, particularly via gaming of the measurement and verification process. There are significant issues with the current approach to measuring demand-side response MW, which is the basis on which program participants are paid. Recent changes to the settlement review process represent clear improvements, but do not go far enough. Additional improvements in measurement and verification methods must be implemented in order to ensure the credibility of PJM demand-side programs. The principal barriers to the further development of demand-side response are in the interface between wholesale and retail markets.

- Reiteration by PJM and the Midwest ISO of their initial recommendation to create an energy schedule tag archive, as this would provide the transparency necessary for a complete loop flow analysis. The MMU recommends that the RTOs request action, and that both NERC and FERC consider taking the action required to make these data available to the RTOs and market monitors to make a full market analysis possible.

  PJM continues to face significant loop flows for reasons that continue not to be fully understood because PJM and other balancing authority operators have inadequate access to the data required for a complete analysis of loop flow in the Eastern Interconnection. A complete analysis of loop flow across the Eastern Interconnection could improve overall market efficiency, shed light on the interactions among market and non market areas and permit market based congestion management across the Eastern Interconnection. Loop flows have negative impacts on the efficiency of market prices in markets with explicit locational pricing and can be evidence of attempts to game such markets. Loop flows also have poorly understood impacts on non market areas.

- Continued improvement of pricing between PJM and surrounding areas, both market and non market.

  Transactions with other market areas are largely driven by the market fundamentals within each area and between market areas. However, there is room to improve current market-to-market coordination to ensure that these areas together more closely approach the outcomes and opportunities of a single, transparent market. PJM and NYISO, as neighboring market areas, should develop market-based congestion management protocols, modeled on the PJM and Midwest ISO JOA, as soon as practicable. Transactions with non market areas are driven by a mix of incentives including market fundamentals but are more difficult to manage because of the inherent inconsistency between the contract path approach taken in non market areas and the explicit locational price approach in market areas. A significant issue is the ability of non market transactions to impose uncompensated costs on market areas in the absence of transparency and appropriate market signals. The reverse can also occur. For interactions with non market areas, the goal should be to increase the role of market forces consistent with actual power flows and more closely approach the outcomes and opportunities of a single, transparent market.

- Continued enhancement of mechanisms used to manage flows at the interfaces between PJM and surrounding areas to ensure competitive outcomes.

  Changes in net interchange affect PJM operations and markets as they require increases or decreases in generation to meet load. As a result of the fact that ramp is free but is a valuable resource, there are strong incentives to game the ramp rules. The new spot import rules have incented participant actions to evade the limits and to hoard spot import capability. PJM should reconsider whether the new approach to limiting spot import service is required or whether a return to the prior policy with an explicit system of managing any related congestion is preferable. Up-to congestion service is a market option used to import power to or export power from PJM which can create mismatches between transactions in the Day-Ahead Energy Market and the Real-Time Energy Market that result in inaccurate pricing and can provide a gaming opportunity. PJM should consider eliminating all internal PJM buses for use in up-to congestion bidding. In effect, the use of specific buses is equivalent to creating a scheduled transaction which will not equal the actual corresponding power flow.

- Continued enhancement of PJM's posting of market data to promote market efficiency.

  PJM has expanded the types and extent of data posted to the Web for public access. PJM should continue to expand data posting, but only to the extent consistent with the goal of improving market efficiency and stimulating competition. As an example, PJM should consider posting generator outage data when it becomes available to PJM.

- Continued efforts to incorporate transmission investments into competitive markets.

  PJM has improved its approach to the cost-benefit analysis of transmission investments. PJM should continue to critically evaluate its approach, particularly as it applies to constraints with large and persistent market impacts. Transmission investments have not been fully incorporated into competitive markets. The construction of new transmission facilities, and the lack of existing transmission, can have significant impacts on energy and capacity markets, but there is no market mechanism in place that would require direct competition between transmission and generation to meet loads in an area. PJM has taken a first step towards integrating transmission investments into the market through the use of economic evaluation metrics. Economic evaluation metrics can be used to determine whether there are positive economic benefits associated with an investment in transmission that might warrant the investment even when it is not required for reliability. The goal of transmission planning should ultimately be the incorporation of transmission investment decisions into market driven processes as much as possible.

- Based on the experience of the MMU during its tenth year and its analysis of the PJM markets and based on the outcome of the active, public process that addressed the independence of market monitoring via a public, approved settlement, the MMU is confident that the market monitoring function will continue to be independent, well-organized, well-defined, clear to market participants and consistent with the policies of the FERC.[4, 5]

4 PJM. "Open Access Transmission Tariff (OATT)," "Attachment M: PJM Market Monitoring Plan," Fourth Revised Sheet No. 452 (Effective August 1, 2008). Section VII.A. states: "The reports to the PJM Board shall include recommendations as to whether changes to the Market Monitoring Unit or the Plan are required."

5 On December 19, 2007, the parties filed a settlement with the Federal Energy Regulatory Commission, pursuant to the September 20, 2007, order in Docket Nos. EL07-56-000 and EL07-58-000 (consolidated).

New Action

- Enhancement of PJM's scarcity pricing rules in the energy market to create regional scarcity signals that reflect stages of scarcity in order to ensure competitive prices when scarcity conditions exist in market regions. Scarcity revenues to generation owners can come entirely from energy markets or they can come from a combination of energy and capacity markets. The approach to scarcity must reflect the fact that revenues in the capacity market are scarcity revenues. If the revenues collected in the RPM market are adequate, it is not essential that a scarcity pricing mechanism exist in the energy market. Nonetheless, it would be preferable to have a scarcity pricing mechanism in the energy market because it provides direct, market-based incentives to load and generation at the margin, as long as the market rules are designed to ensure that scarcity revenues directly offset RPM revenues to prevent double collection of scarcity revenues. The most straightforward way to ensure that such over collection does not occur would be to ensure that capacity resources do not receive scarcity revenues in the energy market in the first place. The settlements process can remove any scarcity revenues from payments to capacity resources and eliminate the need for a complex, uncertain, after the fact procedure for offsetting scarcity revenues in the capacity market.

  The market scarcity signal needs further refinement. Under the current rules, a scarcity pricing event sets prices for all generators in the defined area at the same level, equal to the highest accepted offer within a scarcity pricing region. More flexible and locational scarcity signals could be implemented via reserve requirements modeled as constraints for scarcity regions, with administrative scarcity penalty factors, in the security constrained dispatch. The level of the penalty factor and the reserve target would be determined by the severity level of the scarcity event. This would provide a means to signal scarcity that is consistent with economic dispatch, consistent with locational pricing and consistent with competitive market outcomes. The trigger for each stage should be based on the level of available operating reserve using a dynamically determined and relevant operating reserve requirement and the progressive use of emergency measures. If implemented using reserve requirement constraints with escalating penalty factors, the scarcity pricing mechanism would eliminate the need to lift offer capping during a scarcity pricing event.

- Implementation of rules governing the definition of final prices to ensure certainty for market participants.

  Changing market prices after the fact should be avoided, even when the reason is a failure to mitigate local market power. Markets depend on prices and market participants depend on the finality and certainty of prices. Ideally, observed prices in real time would be final, but this has not yet been possible in the PJM markets. PJM should consider and implement rules defining when prices are final. This approach to final prices is also consistent with the view that market power mitigation should be done ex ante, whenever possible, to ensure that market price signals are accurate in real time.

- Implementation of improved cost-based data submission to permit better monitoring and better analysis of markets.

  PJM should consider and implement rules requiring the submission of the components of cost-based generation offers. The components should include fuel type and cost, variable operating and maintenance expense and the cost of environmental permits by emission type. Such data will permit better monitoring of generation offers and will permit better analysis of the impacts of environmental regulations on PJM markets.

SECTION 2 – ENERGY MARKET, PART 1

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 2008, including market size, concentration, residual supply index, price-cost markup, net revenue and price.[1] The MMU concludes that the PJM Energy Market results were competitive in 2008.

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 outcomes in PJM markets. One of the MMU's primary goals is to identify actual or potential market design flaws.[2] PJM's market power mitigation goals have 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 only 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.

Overview

Market Structure

- **Supply.** During the June to September 2008 summer period, the PJM Energy Market received an hourly average of 154,959 MW in supply offers including hydroelectric generation.[3] The summer 2008 average supply offers were 15 MW higher than the summer 2007 average supply of 154,944 MW.

- **Demand.** The PJM system peak load in 2008 was 130,100 MW in the hour ended 1700 EPT on June 9, 2008, while the PJM peak load in 2007 was 139,428 in the hour ended 1600 on August 8, 2007.[4] The 2008 peak load was 9,328 MW, or 6.7 percent, lower than the 2007 peak load.

1 Analysis of 2008 market results requires comparison to prior years. During calendar years 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. 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 *2008 State of the Market Report*, Volume II, Appendix A, "PJM Geography."

2 See PJM. "Open Access Transmission Tariff (OATT)," "Attachment M: Market Monitoring Plan," First Revised Sheet No. 448.05 (Effective August 1, 2008).

3 Calculated values shown in Section 2, "Energy Market, Part 1," are based on unrounded, underlying data and may differ from calculations based on the rounded values shown in tables.

4 For the purpose of Volume I and Volume II of the *2008 State of the Market Report*, all hours are presented and all hourly data are analyzed using Eastern Prevailing Time (EPT). See Appendix M, "Glossary," for a definition of EPT and its relationship to Eastern Standard Time (EST) and Eastern Daylight Time (EDT).

- **Market Concentration.** Concentration ratios are a summary measure of market share, a key element of market structure. High concentration ratios indicate comparatively smaller numbers of sellers dominating a market, while low concentration ratios mean larger numbers of sellers splitting market sales more equally. High concentration ratios indicate an increased potential for participants to exercise market power, although low concentration ratios do not necessarily mean that a market is competitive or that participants cannot exercise market power. Analysis of the PJM Energy Market indicates moderate market concentration overall. Analyses of supply curve segments indicate moderate concentration in the baseload segment, but high concentration in the intermediate and peaking segments.

- **Local Market Structure and Offer Capping.** Noncompetitive local market structure is the trigger for offer capping. PJM applied a flexible, targeted, real-time approach to offer capping (the three pivotal supplier test) as the trigger for offer capping in 2008. PJM offer caps units only 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 offer-capped unit hours were 0.2 percent in 2008, the same level as 2007. In the Real-Time Energy Market offer-capped unit hours fell from 1.1 percent in 2007 to 1.0 percent in 2008.

- **Local Market Structure.** A summary of the results of PJM's application of the three pivotal supplier test is presented for all constraints which occurred for 100 or more hours during calendar year 2008. The analysis of the application of the three pivotal supplier test to local markets demonstrates that it is working successfully to ensure that owners are not subject to offer capping when the market structure is competitive and to offer cap only pivotal owners when the market structure is noncompetitive.

Market Performance: Markup, Load and Locational Marginal Price

- **Markup.** The markup conduct of individual owners and units has an impact on market prices. The MMU calculates explicit measures of the impact of marginal unit markups on LMP. The LMP impact is a measure of market power. The price impact of markup must be interpreted carefully. The price impact is not based on a full redispatch of the system, as such a full redispatch is practically impossible because it would require reconsideration of all dispatch decisions and unit commitments. The markup impact includes the maximum 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.

  The markup component of the overall system load-weighted, average LMP was $2.04 per MWh, or 3 percent. The markup was $3.27 per MWh during peak hours and $.74 per MWh during off-peak hours. The overall results support the conclusion that prices in PJM are set, on average, by marginal units operating at or close to their marginal costs. This is strong evidence of competitive behavior and competitive market performance.

- **Load.** On average, PJM real-time load decreased in 2008 by 2.7 percent from 2007, falling from 81,681 MW to 79,515 MW.

- **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. For example, overall average prices subsume congestion and price differences over time.

  PJM Real-Time Energy Market prices rose in 2008 over 2007. The system simple average LMP was 15.3 percent higher in 2008 than in 2007, $66.40 per MWh versus $57.58 per MWh. The load-weighted LMP was 15.4 percent higher in 2008 than in 2007, $71.13 per MWh versus $61.66 per MWh. The fuel-cost-adjusted, load-weighted, average LMP was 16.0 percent lower in 2008 than in 2007, $51.79 per MWh compared to $61.66 per MWh. Fuel costs in 2008 contributed to upward pressure on LMP.

- **Retroactive Change to LMP.** On September 24, 2008, PJM retroactively changed Real-Time, LMP for September 4, 2008, for hours ending 15 through 21 and the hour ending 24, and notified PJM members. The largest positive zonal impact was in the Dominion Control Zone, which experienced an average $2.43 per MWh increase as a result of the change, and the largest negative zonal impact occurred in the PECO Control Zone, which experienced an average $2.28 per MWh decrease as a result of the change. The largest positive bus-specific impact occurred at the Mt Laurel 413 KV TX1 bus, in the PSEG Control Zone, which experienced an average $29.86 per MWh increase after the changes, and the largest negative bus-specific impact occurred at the Bonsack 138 KV T1 bus, in the AEP Control Zone, which experienced an average $24.10 per MWh decrease after the changes.

- **Load and Spot Market.** Real-time load is served by a combination of self-supply, bilateral market purchases and spot market purchases. From the perspective of a single PJM parent company 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 2008, 14.6 percent of real-time load was supplied by bilateral contracts, 20.1 percent by spot market purchases and 65.2 percent by self-supply. Compared with 2007, reliance on bilateral contracts decreased by 2.0 percentage points; reliance on spot supply increased by 4.2 percentage points; and reliance on self-supply decreased by 2.3 percentage points in 2008.

Demand-Side Response

- **Demand-Side Response (DSR).** Markets require both a supply side and a demand side to function effectively. PJM wholesale market, demand-side programs should be understood as one relatively small part of a transition to a fully functional demand side for its Energy Market. A fully developed demand side will include retail programs and an active, well-articulated interaction between wholesale and retail markets. There are significant issues with the current approach to measuring demand-side response MW, which is the basis on which program participants are paid. The current approach can and has resulted in payments when the customer has taken no action to respond to market prices. A substantial improvement in measurement and verification methods must be implemented in order to ensure the credibility of PJM demand-side programs. Recent changes to the settlement review process represent clear improvements, but do not go far enough.

Total demand-side response resources available in PJM on June 9, 2008 (the peak day in 2008), were 4,439.2 MW eligible for capacity credits and 1,898.8 MW eligible for energy payments from the Emergency Load-Response Program and 2,294.7 MW from the Economic Load-Response Program.

Conclusion

The MMU analyzed key elements of PJM Energy Market structure, participant conduct and market performance for calendar year 2008, including aggregate supply and demand, concentration ratios, local market concentration ratios, price-cost markup, offer capping, participation in demand-side response programs, loads and prices in this section of the report. The next section continues the analysis of the PJM Energy Market including additional measures of market performance.

Aggregate supply increased by about 15 MW when comparing the summer of 2008 to the summer of 2007 while aggregate peak load decreased by 9,328 MW, modifying the general supply demand balance from 2007 with a corresponding impact on peak Energy Market prices. Overall load was also lower than in 2007. Market concentration levels remained moderate and average markup decreased. This relationship between supply and demand, regardless of the specific market, balanced by market concentration, is referred to as 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.

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. LMP is a broader indicator of the level of competition. While PJM has experienced price spikes, these have been limited in duration and, in general, prices in PJM have been well below the marginal cost of the highest cost unit installed on the system. The significant price spikes in PJM have been directly related to scarcity conditions. In PJM, prices tend to increase as the market approaches scarcity conditions as a result of generator offers and the associated shape of the aggregate supply curve. The pattern of prices within days and across months and years illustrates how prices are directly related to demand conditions and thus also illustrates the potential significance of price elasticity of demand in affecting price.

On September 24, 2008, PJM retroactively changed prices for eight hours for September 4, 2008. Changing market prices after the fact should be avoided, even when the reason is a failure to mitigate local market power, as it was here. Markets depend on prices and market participants depend on the finality and certainty of prices. Ideally, observed prices in real time would be final, but this has not yet been possible in the PJM markets. Nonetheless, PJM makes it a practice to finalize prices for the Real-Time Energy Market by noon the following day. This approach to final and certain prices is also consistent with the view that market power mitigation should be done ex ante, whenever possible, to ensure that market price signals are accurate in real time.

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. 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, as implemented, is consistent with the United States Federal Energy Regulatory Commission's (FERC's) market power tests, encompassed under the delivered price test. The three pivotal supplier test is an application of the delivered price test to both the Real-Time Market and hourly Day-Ahead Market. 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 successfully to exempt owners when the local market structure is competitive and to offer cap owners when the local market structure is noncompetitive.

Energy Market results for 2008 generally reflected supply-demand fundamentals. Higher prices in the Energy Market were the result of higher fuel costs. The load-weighted, average LMP for 2008 was 15.4 percent higher than the load-weighted, average LMP for 2007. The fuel-cost-adjusted, load-weighted, average LMP in 2008 was 16.0 percent lower than the load-weighted LMP in 2007. If fuel costs for the year 2008 had been the same as for 2007, the 2008 load-weighted LMP would have been lower, $51.79 per MWh, instead of the observed $71.13 per MWh. Higher coal, gas and oil prices in 2008 resulted in higher prices in 2008 than would have occurred if fuel prices had remained at 2007 levels.

The overall market results support the conclusion that prices in PJM are set, on average, by marginal units operating at, or close to, their marginal costs. This is evidence of competitive behavior and competitive market outcomes. Given the structure of the Energy Market, tighter markets or a change in participant behavior remain potential sources of concern in the Energy Market. The MMU concludes that the PJM Energy Market results were competitive in 2008.

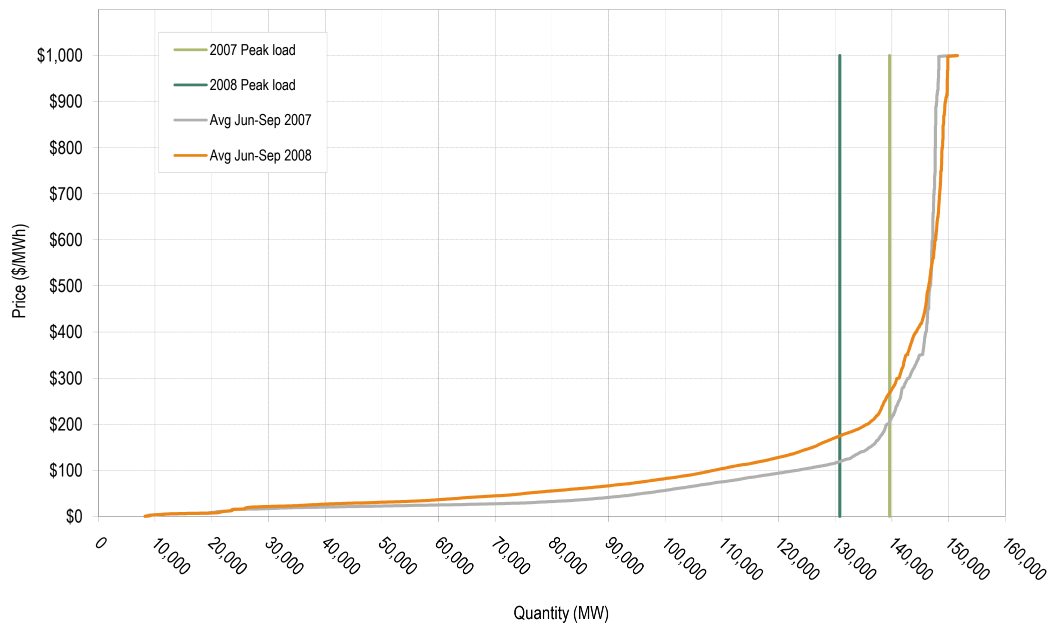
Market Structure

Supply

During the June to September 2008 summer period, the PJM Energy Market received an hourly average of 154,959 MW in total supply offers including hydroelectric generation. The summer 2008 average daily offered supply was 15 MW higher than the summer 2007 average daily offered supply of 154,944. The increase was comprised of 1,885 MWh of decreased hydroelectric power offers and 1,900 MWh of increased offers from non-hydroelectric capacity. During the summer of 2008, the peak demand was 9,328 MW, or 6.7 percent, lower than the 2007 peak, which, when combined with the upward shift of the 2008 supply curve, results in only a small difference in the price level at the supply-demand intersections. (See Figure 2-1.)

Offer prices on the 2008 supply curve are higher than on the 2007 supply curve from total supply levels of about 24,000 MW to 147,000 MW, corresponding to 2008 offers from about $15 per MWh to about $544 per MWh. During 2008, this range of offers consisted of coal-fired steam, natural gas-fired steam, combined-cycle (CC) and efficient combustion turbine (CT) units. The increase in the offer curve was primarily driven by higher fuel prices for summer 2008 compared to summer 2007. The weighted average price of coal increased by 87 percent to $4.01 per MBtu for the summer periods of 2008, the price of natural gas rose 52 percent to $10.44 per MBtu and the price of oil increased 66 percent to $23.33 per MBtu.[5]

Figure 2-1 Average PJM aggregate supply curves: Summers 2007 and 2008



During the 12 months ended May 31, 2008, 15 new units entered service in the RTO. The 15 new units included four new wind resources totaling 60.9 MW, three new diesel resources totaling 23.3 MW, two units that came out of retirement totaling 112.6 MW and six units were the result of the reclassification of external units. Total internal RTO unforced capacity increased in the 2008-2009 RPM auction by 1,762.0 MW to 156,968.0 MW from 155,206.0 MW in the 2007-2008 RPM auction. This was due to new generation (84.2 MW), units which came out of retirement (112.6 MW), capacity upgrades to existing generation and increases in demand resources, net of unit retirements (79.8 MW) and derations to existing generation and demand capacity resources. Of the 1,762.0 MW increase in total internal RTO unforced capacity, 818.5 MW were due to voluntary reductions in sell offer EFORds in the 2008-2009 auction. Of the remaining 943.5 MW, 348.2 MW (about 34 percent) were generation and 595.3 MW (about 66 percent) were DR.

Table 2-1 shows units retired during the 12 months ended May 31, 2008. Waukegan 6 retired from the ComEd zone on January 31, 2008. It was a 100 MW (79.8 UCAP, as mentioned above) sub-critical coal steam unit located in Illinois.

5 The 87 percent increase in the average price of coal consists of a 109 percent increase in the price of Central Appalachian coal, an 87 percent increase in the price of Northern Appalachian coal, a 28 percent increase in the price of Powder River Basin coal and a 73 percent increase in the price of Illinois Basin coal.

Table 2-1 Retired units: June 1, 2007, to May 31, 2008

Unit Name	Installed Capacity (MW)	Unit Type	Retire Date
ComEd Waukegan 6	100	Sub-Critical Coal	1/31/08

The net result of generation additions and subtractions, holding other factors constant, was a slight shift to the right of the aggregate supply curve. The shape of the aggregate supply curve changed only slightly as a result since the net increase in generation was less than 0.5 percent of the system supply.

Demand

Table 2-2 shows the actual coincident summer peak loads for the years 1999 through 2008.[6] The 2008 actual summer peak load of 130,100 MW was 9,328 MW less than the 2007 summer peak load of 139,428.

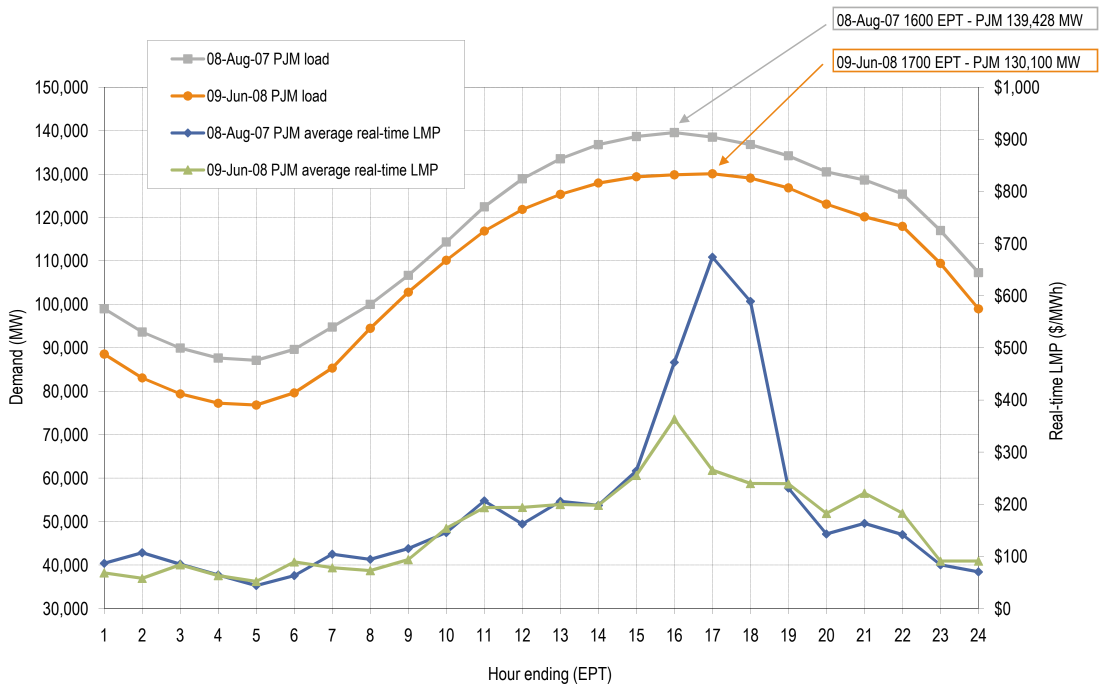
Table 2-2 Actual PJM footprint summer peak loads: 1999 to 2008

Year	Date	Hour Ending (EPT)	PJM Load (MW)	Difference (MW)
1999	06-Jul-99	1400	59,365	NA
2000	26-Jun-00	1600	56,727	(2,638)
2001	09-Aug-01	1500	54,015	(2,712)
2002	14-Aug-02	1600	63,762	9,747
2003	22-Aug-03	1600	61,500	(2,262)
2004	03-Aug-04	1700	77,887	16,387
2005	26-Jul-05	1600	133,763	55,876
2006	02-Aug-06	1700	144,644	10,881
2007	08-Aug-07	1600	139,428	(5,216)
2008	09-Jun-08	1700	130,100	(9,328)

6 Peak loads shown are eMTR load. See the *2008 State of the Market Report*, Volume II, Appendix I, "Load Definitions," for detailed definitions of load.

The hourly load and average PJM LMP for the 2008 and 2007 summer peak days are shown in Figure 2-2.

Figure 2-2 PJM summer peak-load comparison: Monday, June 9, 2008, and Wednesday, August 8, 2007



Market Concentration

During 2008, concentration in the PJM Energy Market was moderate overall. Analyses of supply curve segments indicate moderate concentration in the baseload segment, but high concentration in the intermediate and peaking segments.[7] High concentration levels, particularly in the peaking segment, increase the probability that a generation owner will be pivotal 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 and generation owners' obligations to serve load were effective in most cases in preventing the exercise of market power in these areas during 2008. If those obligations were to change or the rules were to change, however, the market power related incentives and impacts would change as a result.

Concentration ratios are a summary measure of market share, a key element of market structure. High concentration ratios indicate that comparatively small numbers of sellers dominate a market; low concentration ratios mean larger numbers of sellers split market sales more equally. The best tests of market competitiveness are direct tests of the conduct of individual participants and their impact on price. The direct examination of offer behavior by individual market participants is one such test. Low aggregate market concentration ratios establish neither that a market is competitive nor that participants are unable to exercise market power. High concentration ratios do, however, indicate an increased potential for participants to exercise market power.

7 For the market concentration analysis, supply curve segments are based on a classification of units that generally participate in the PJM Energy Market at varying load levels. Unit class is a primary factor for each classification; however, each unit may have different characteristics that influence the exact segment for which it is classified.

Despite their significant limitations, concentration ratios provide useful information on market structure. 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. (See Table 2-3.)

Actual net imports and import capability were incorporated in the hourly Energy Market HHI calculations because imports are a source of competition for generation located in PJM. Energy can be imported into PJM under most conditions. The hourly HHI was calculated by combining all export and import transactions from each market participant with its generation output from each hour. A market participant's market share increases with imports and decreases with exports.

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.[8]

PJM HHI Results

Calculations for hourly HHI indicate that by the FERC standards, the PJM Energy Market during 2008 was moderately concentrated. (See Table 2-3.) Based on the hourly Energy Market measure, average HHI was 1150 with a minimum of 847 and a maximum of 1434 in 2008. The highest hourly market share was 29 percent and the highest average market share for 2008 was 21 percent.

Table 2-3 PJM hourly Energy Market HHI: Calendar year 2008

	Hourly Market HHI
Average	1150
Minimum	847
Maximum	1434
Highest market share (One hour)	29%
Highest market share (All hours)	21%
# Hours	8784
# Hours HHI > 1800	0
% Hours HHI > 1800	0%

8 77 FERC ¶ 61,263, "Inquiry Concerning the Commission's Merger Policy under the Federal Power Act: Policy Statement," Order No. 592, pp. 64-70.

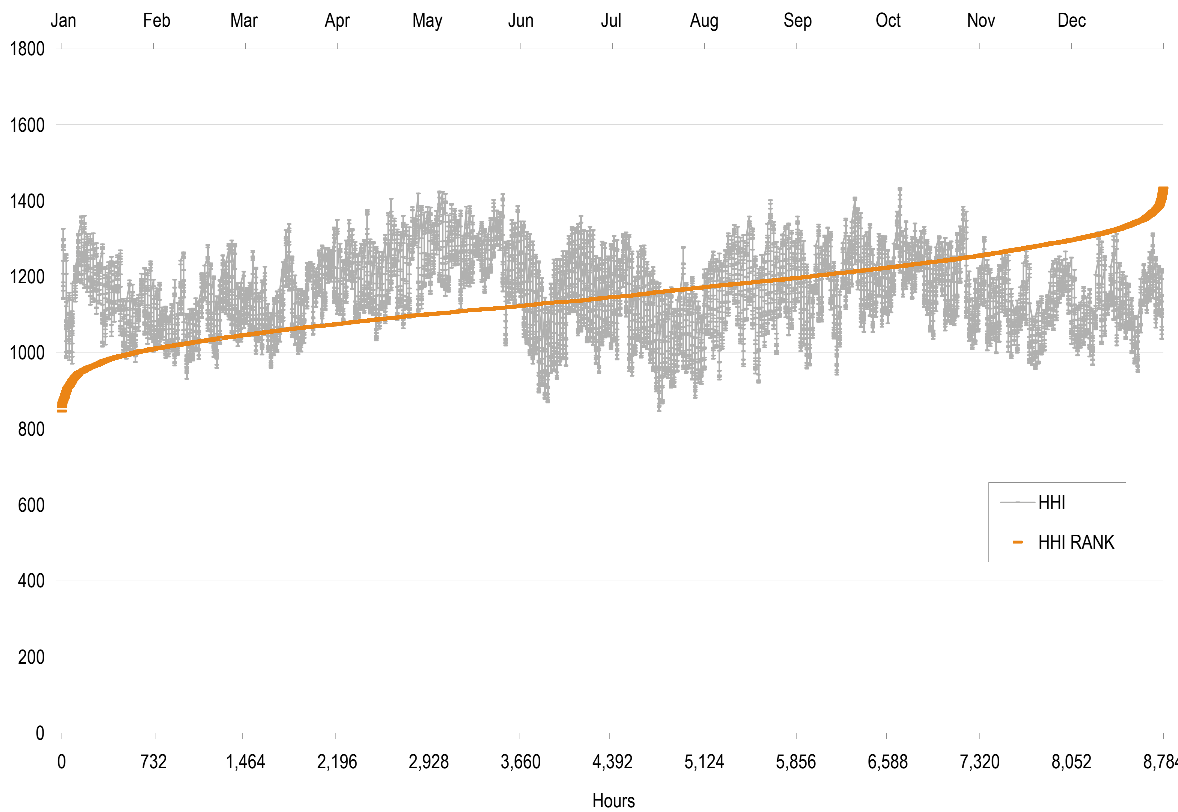
Table 2-4 includes 2008 HHI values by supply curve segment, including base, intermediate and peaking plants. The hourly measure indicates that, on average, intermediate and peaking segments of the supply curve are highly concentrated, while the baseload segment is moderately concentrated.

Table 2-4 PJM hourly Energy Market HHI (By segment): Calendar year 2008

	Minimum	Average	Maximum
Base	1225	1549	1984
Intermediate	683	2130	6216
Peak	632	5476	10000

Figure 2-3 presents the 2008 hourly HHI values in chronological order and an HHI duration curve that shows 2008 HHI values in ascending order of magnitude. The HHI values were in the unconcentrated range for 6.5 percent of the hours while HHI values were in the moderately concentrated range in the remaining 93.5 percent of hours, with a maximum value of 1434, as shown in Table 2-3.

Figure 2-3 PJM hourly Energy Market HHI: Calendar year 2008



Local Market Structure and Offer Capping

In the PJM Energy Market, offer capping occurs only as a result of structurally noncompetitive local markets and noncompetitive offers in the Day-Ahead and Real-Time Energy Markets. 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 market power mitigation to situations where market structure is not competitive and thus where market design alone cannot mitigate market power.

PJM has clear rules limiting the exercise of local market power.[9] The rules provide for offer capping when conditions on the transmission system create a structurally noncompetitive local market (as measured by the three pivotal supplier test), when units in that local market have made noncompetitive offers and when such offers would set the price above the competitive level in the absence of mitigation. Offer caps are set at the level of a competitive offer. Offer-capped units receive the higher of the market price or their offer cap. Thus, if broader market conditions lead to a price greater than the offer cap, the unit receives the higher market price. The rules governing the exercise of local market power recognize that units in certain areas of the system would be in a position to extract monopoly profits, but for these rules. The offer-capping rules exempted certain units from offer capping based on the date of their construction. Such exempt units could, and did, exercise market power, at times, that would not have been permitted if the units had not been exempt. The FERC eliminated the exemption effective May 17, 2008.[10]

Under existing rules, PJM does not apply offer capping to suppliers when structural market conditions, as measured by the three pivotal supplier test, indicate that such suppliers are reasonably likely to behave in a competitive manner. The goal is to apply a clear rule to limit the exercise of market power by generation owners in load pockets, but to apply the rule in a flexible manner in real time and to lift offer capping when the exercise of market power is unlikely based on the real-time application of the market structure screen.

PJM's three pivotal supplier test represents the practical application of the FERC market power tests in real time.[11] The three pivotal supplier test is passed if no three generation suppliers in a load pocket are jointly pivotal. Stated another way, if the incremental output of the three largest suppliers in a load pocket is removed and enough incremental generation remains available to solve the incremental demand for constraint relief, where the relevant competitive supply includes all incremental MW at a cost less than, or equal, to 1.5 times the clearing price, then offer capping is suspended.

9 See PJM. "Amended and Restated Operating Agreement (OA)," Schedule 1, Section 6.4.2. (January 19, 2007).

10 123 FERC ¶ 61,169 (2008).

11 See the *2008 State of the Market Report*, Volume II, Appendix L, "Three Pivotal Supplier Test."

Levels of offer capping have historically been low in PJM, as shown in Table 2-5.

Table 2-5 Annual offer-capping statistics: Calendar years 2004 to 2008

	Real Time		Day Ahead	
	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2004	1.3%	0.4%	0.6%	0.2%
2005	1.8%	0.4%	0.2%	0.1%
2006	1.0%	0.2%	0.4%	0.1%
2007	1.1%	0.2%	0.2%	0.0%
2008	1.0%	0.2%	0.2%	0.1%

Table 2-6 presents data on the frequency with which units were offer capped in 2008. Table 2-6 shows the number of generating units that met the specified criteria for total offer-capped run hours and percentage of total run hours that were offer-capped for 2008. For example, in 2008, only 1 unit was offer-capped for greater than, or equal to, 80 percent of its run hours and had 300 or more offer-capped run hours.

Table 2-6 Offer-capped unit statistics: Calendar year 2008

			2008 Offer-Capped Hours			
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	0	0	0	1	1	4
80% and < 90%	0	0	1	0	4	10
75% and < 80%	0	0	5	4	4	11
70% and < 75%	1	0	1	2	4	9
60% and < 70%	1	0	0	4	4	30
50% and < 60%	0	0	2	3	3	20
25% and < 50%	0	5	10	11	10	57
10% and < 25%	1	0	1	0	6	48

Table 2-6 shows that a small number of units are offer capped for a significant number of hours or for a significant proportion of their run hours. For example, only 53 units (about 4 percent of all units) that had offer-capped run hours of at least 200 hours (about 2 percent of all hours) in 2008 were offer capped for 10 percent or more of their run hours. Only 8 units (or about 0.7 percent of all units) that had greater than, or equal to, 400 offer-capped run hours were offer capped for 10 percent or more of their run hours.

When compared to the 2007 offer-capped statistics, 54 percent of the categories show an increase in the number of units; 17 percent of the categories show no change and 29 percent of the categories show a decrease in the number of units.[12]

12 See the *2008 State of the Market Report*, Volume II, Appendix C, “Energy Market” Table C-24 for 2007 data.

When compared to the 2006 offer-capped statistics, 48 percent of the categories show an increase in the number of units; 21 percent of the categories show no change and 31 percent of the categories show a decrease in the number of units.[13]

Units that are offer capped for greater than, or equal to, 60 percent of their run hours are designated as frequently mitigated units (FMUs). An FMU or units that are associated with the FMU (AUs) are entitled to include adders in their cost-based offers that are a form of local scarcity pricing.

Local Market Structure

In 2008, the PSEG, AP, AEP, JCPL, PENELEC, Dominion, DPL, AECO, DLCO, ComEd, PECO and Pepco Control Zones experienced congestion resulting from one or more constraints binding for 100 or more hours. Using the three pivotal supplier results for calendar year 2008, actual competitive conditions associated with each of these frequently binding constraints were analyzed in real time.[14] The Met-Ed, BGE, PPL, RECO and DAY Control Zones were not affected by constraints binding for 100 or more hours.

The three pivotal supplier test is applied by PJM on an ongoing basis in order to determine whether offer capping is required to prevent the exercise of local market power for any constraint not exempt from offer capping. The FERC eliminated the exemption of interfaces effective May 17, 2008.[15] The MMU analyzed the results of the three pivotal supplier tests conducted by PJM for the Real-Time Energy Market for the period January 1, 2008, through December 31, 2008.

Overall, the results confirm that the three pivotal supplier test results in offer capping when the local market is structurally noncompetitive and does not result in offer capping when that is not the case. Local markets are noncompetitive when there is a small number of suppliers. The number of hours in which one or more suppliers pass the three pivotal supplier test and are not subject to offer capping increases as the number of suppliers in the local market increases. For example, the regional constraints have a larger number of suppliers and more than 62 percent of the three pivotal supplier tests have one or more passing owners. In contrast, more local constraints like the Bedington – Harmony 138 kV line in the AP Control Zone have only two suppliers and therefore are always structurally noncompetitive.

The fact that some constraints never had any generation resources that failed the three pivotal supplier test during the period analyzed does not lead to the conclusion that such constraints should never have offer capping for local market power. The same logic applies to interface constraints which were exempt from offer capping prior to May 17, 2008. Even if no generation resources associated with any of the previously exempt interface constraints failed the three pivotal suppler test during the period analyzed, that does not mean that such interfaces should always be exempt from offer capping for local market power. The fact that one or more generation resources, required to resolve these interfaces, did fail the three pivotal supplier test at times simply reinforces the point. If the generation resources associated with these interfaces always pass the three pivotal

13 See the *2008 State of the Market Report*, Volume II, Appendix C, "Energy Market" Table C-23 for 2006 data.
14 See the *2008 State of the Market Report*, Volume II, Appendix L, "Three Pivotal Supplier Test" for a more detailed explanation of the three pivotal supplier test.
15 123 FERC ¶ 61,169 (2008).

supplier test, there will be no offer capping; and conversely if such resources at times fail the three pivotal supplier test, appropriate offer capping will be applied.

Information is provided for each constraint including the number of tests applied and the number of tests in which one or more owners passed and/or failed the three pivotal supplier test.[16] Additional information is provided for each constraint including the average MW required to relieve a constraint, the average supply available, the average number of owners included in each test and the average number of owners that passed or failed each test.

- **Regional 500 kV Constraints.** In 2008, several regional transmission constraints occurred for more than 100 hours. The Kammer 765/500 kV transformer, along with four interface constraints (5004/5005, AP South, Bedington – Black Oak and West) all experienced more than 100 hours of congestion.[17] The three pivotal supplier test was applied to all of these constraints. The AP South and West interfaces are two of the four interfaces for which generation owners were exempt from offer capping prior to May 17, 2008.

  Table 2-7 includes information on the three pivotal supplier test results for the three regional constraints that were never exempt from offer capping.[18] The percentage of tested intervals resulting in one or more owners passing ranged from 62 percent to 90 percent while 21 percent to 48 percent of the tests show one or more owners failing.

Table 2-7 Three pivotal supplier results summary for three regional constraints: Calendar year 2008

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
5004/5005 Interface	Peak	723	652	90%	149	21%
	Off Peak	535	467	87%	130	24%
Bedington - Black Oak	Peak	666	491	74%	296	44%
	Off Peak	425	301	71%	193	45%
Kammer	Peak	2,328	1,450	62%	1,111	48%
	Off Peak	4,740	3,302	70%	2,130	45%

16 The three pivotal supplier test in the Real-Time Energy Market is applied by PJM as necessary and may be applied multiple times within a single hour for a specific constraint. Each application of the test is done in a five-minute interval.

17 The 5004/5005 Interface is comprised of two, 500 kV lines, which include the Keystone – Juniata 5004 and the Conemaugh – Juniata 5005. These two lines are located between central and western Pennsylvania.

18 The number of tests with one or more failing owners plus the number of tests with one or more passing owners can exceed the total number of tests applied. A single test can result in one or more owners passing and one or more owners failing. In such a case, the interval would be counted as including one or more passing owners and one or more failing owners.

Table 2-8 shows that, on average, during 2008 peak periods, the local markets created by the 5004/5005 Interface and the Kammer transformer had 18 owners with available supply and 13 owners with available supply, respectively. Of those owners, an average of 16 passed the test for the 5004/5005 Interface and an average of 10 passed the test for the Kammer transformer.[19] During off-peak periods, on average, the 5004/5005 Interface and the Kammer transformer had 16 owners with available supply and 14 owners with available supply. Of those owners, an average of 14 passed the test for the 5004/5005 Interface and an average of 10 passed the test for the Kammer transformer. Bedington – Black Oak, on average, had 12 owners with available supply and eight owners passed the test during on-peak periods and had 10 owners with available supply and seven owners passed the test during off-peak periods.

Table 2-8 Three pivotal supplier test details for three regional constraints: Calendar year 2008

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
5004/5005 Interface	Peak	80	352	18	16	2
	Off Peak	84	313	16	14	2
Bedington - Black Oak	Peak	75	174	12	8	4
	Off Peak	58	191	10	7	3
Kammer	Peak	57	207	13	10	3
	Off Peak	62	234	14	10	4

For the AP South and West interfaces, which were exempt from offer capping prior to May 17, 2008, Table 2-9 and Table 2-10 provide information on the three pivotal supplier test results from January 1, 2008 through May 16, 2008 and from May 17, 2008 through December 31, 2008. From January 1, 2008 through May 16, 2008, the percentage of tested intervals resulting in one or more owners passing ranged from 71 percent to 94 percent while 11 percent to 46 percent of the tests show one or more owners failing. From May 17, 2008 through December 31, 2008, the percentage of tested intervals resulting in one or more owners passing ranged from 61 percent to 97 percent while 7 percent to 61 percent of the tests show one or more owners failing.

Table 2-9 Three pivotal supplier results summary for the AP South and West interfaces: January 1, 2008, through May 16, 2008

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
AP South	Peak	634	464	73%	273	43%
	Off Peak	903	641	71%	414	46%
West	Peak	578	543	94%	64	11%
	Off Peak	455	420	92%	77	17%

19 The average number of owners passing and the average number of owners failing are rounded to the nearest whole number and may not sum to the average number of owners, also rounded to the nearest whole number.

Table 2-10 Three pivotal supplier results summary for the AP South and West interfaces: May 17, 2008, through December 31, 2008

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
AP South	Peak	1,575	1,088	69%	766	49%
	Off Peak	1,053	643	61%	639	61%
West	Peak	334	325	97%	22	7%
	Off Peak	186	162	87%	38	20%

Table 2-11 and Table 2-12 provide information on the three pivotal supplier test results for the AP South and West interfaces, from January 1, 2008 through May 16, 2008 and from May 17, 2008 through December 31, 2008. For AP South, on average, 12 out of 17 owners passed the test during on-peak periods and 10 out of 14 owners passed the test during off-peak periods from January 1, 2008 through May 16, 2008, and on average, 10 out of 15 owners passed the test during on-peak periods and 7 out of 12 owners passed the test during off-peak periods from May 17, 2008 through December 31, 2008. For the West Interface, on average, 16 out of 18 owners passed the test during on-peak periods, and 14 out of 16 owners passed the test during off-peak periods from January 1, 2008 through May 16, 2008, and on average, 19 out of 19 owners passed the test during on-peak periods and 16 out of 18 owners passed the test during off-peak periods from May 17, 2008 through December 31, 2008.

Table 2-11 Three pivotal supplier test details for the AP South and West interfaces: January 1, 2008, through May 16, 2008

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
AP South	Peak	87	314	17	12	5
	Off Peak	90	332	14	10	5
West	Peak	133	648	18	16	1
	Off Peak	155	708	16	14	2

Table 2-12 Three pivotal supplier test details for the AP South and West interfaces: May 17, 2008, through December 31, 2008

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
AP South	Peak	99	318	15	10	5
	Off Peak	98	291	12	7	5
West	Peak	122	612	19	19	1
	Off Peak	168	644	18	16	2

- **East Interface and Central Interface.** The remaining two interfaces that were exempt until May, the East and Central interface constraints occurred for fewer than 100 hours. The East Interface constraint occurred for 12 hours in 2008, while the Central Interface constraint occurred for 42 hours in 2008. Table 2-13 shows that from January 1, 2008 through May 16, 2008, the percentage of tested intervals resulting in one or more owners passing ranged from 60 percent to 100 percent while less than 40 percent of the tests showed one or more owners failing. Table 2-14 shows that from May 17, 2008 through December 31, 2008, the percentage of tested intervals resulting in one or more owners passing ranged from 79 percent to 100 percent while less than 21 percent of the tests showed one or more owners failing. No tests were applied to the East Interface from May 17, 2008 through December 31, 2008.

Table 2-13 Three pivotal supplier results summary for the East and Central interfaces: January 1, 2008, through May 16, 2008

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Central	Peak	12	11	92%	3	25%
	Off Peak	52	50	96%	9	17%
East	Peak	9	9	100%	0	0%
	Off Peak	10	6	60%	4	40%

Table 2-14 Three pivotal supplier results summary for the East and Central interfaces: May 17, 2008, through December 31, 2008

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Central	Peak	11	9	82%	2	18%
	Off Peak	29	29	100%	2	7%
East	Peak	0	0	NA	0	NA
	Off Peak	29	23	79%	6	21%

Table 2-15 shows that, from January 1, 2008 through May 16, 2008, on average, the local market created by the East Interface had 18 owners during peak periods and all passed the test. During off-peak periods, 9 of 13 passed the test for the East Interface. The local market created by the Central Interface had 16 owners and 15 passed the test during both on-peak and off-peak periods. Table 2-16 shows that, from May 17, 2008 through December 31, 2008, on average, the local market created by the East Interface had 17 owners during off-peak periods and 15 passed the test. No tests were applied to the East Interface during on-peak periods from May 17, 2008 through December 31, 2008. The local market created by the Central Interface had 17 owners during on-peak periods and 13 passed the test. During off-peak periods, 16 of 17 passed the test for the Central Interface.

Table 2-15 Three pivotal supplier test details for the East and Central interfaces: January 1, 2008, through May 16, 2008

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Central	Peak	149	547	16	15	1
	Off Peak	108	432	16	15	1
East	Peak	170	987	18	18	0
	Off Peak	180	639	13	9	4

Table 2-16 Three pivotal supplier test details for the East and Central interfaces: May 17, 2008, through December 31, 2008

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Central	Peak	133	490	17	13	3
	Off Peak	216	833	17	16	0
East	Peak	NA	NA	NA	NA	NA
	Off Peak	128	589	17	15	2

- **PSEG Control Zone Constraints.** In 2008, five constraints in the PSEG Control Zone occurred for more than 100 hours. Table 2-17 and Table 2-18 show the results of the three pivotal supplier tests applied to these constraints. For three of the five constraints, the average number of owners with available supply was four or less. The three pivotal supplier test results reflect this, as the average number of owners that passed is significant only for the Cedar Grove – Clifton 230 kV and the Cedar Grove – Roseland 230 kV lines, which had more than four owners, on average. The Cedar Grove – Clifton 230 kV and the Cedar Grove – Roseland 230 kV lines had more owners and more effective supply and thus a higher percentage of tests with one or more owners that passed the three pivotal supplier test.

Table 2-17 Three pivotal supplier results summary for constraints located in the PSEG Control Zone: Calendar year 2008

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Athenia - Saddlebrook	Peak	79	5	6%	77	97%
	Off Peak	427	2	0%	426	100%
Branchburg - Readington	Peak	653	56	9%	646	99%
	Off Peak	195	3	2%	193	99%
Brunswick - Edison	Peak	536	0	0%	536	100%
	Off Peak	211	0	0%	211	100%
Cedar Grove - Clifton	Peak	772	106	14%	746	97%
	Off Peak	529	107	20%	484	91%
Cedar Grove - Roseland	Peak	117	37	32%	94	80%
	Off Peak	415	80	19%	381	92%

Table 2-18 Three pivotal supplier test details for constraints located in the PSEG Control Zone: Calendar year 2008

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Athenia - Saddlebrook	Peak	15	33	3	0	3
	Off Peak	18	29	3	0	3
Branchburg - Readington	Peak	19	42	4	0	4
	Off Peak	16	45	3	0	3
Brunswick - Edison	Peak	10	112	1	0	1
	Off Peak	8	87	1	0	1
Cedar Grove - Clifton	Peak	32	122	7	1	6
	Off Peak	33	118	7	1	6
Cedar Grove - Roseland	Peak	49	156	9	2	7
	Off Peak	47	145	8	1	7

- **AP Control Zone Constraints.** In 2008, there were seven constraints that occurred for more than 100 hours in the AP Control Zone. Table 2-19 and Table 2-20 show the results of the three pivotal supplier tests applied to the constraints in the AP Control Zone. For three of the seven constraints, the average number of owners with available supply was two. The three pivotal supplier test results reflect this, as the average number of owners that passed is significant only for the three constraints with a larger number of owners, on average. Four constraints, the Elrama – Mitchell 138 kV line, the Mount Storm – Pruntytown 500 kV line, the Sammis – Wylie Ridge 345 kV line and the Mount Storm transformer had more owners and more effective supply and thus a higher percentage of tests with one or more owners that passed.

Table 2-19 Three pivotal supplier results summary for constraints located in the AP Control Zone: Calendar year 2008

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Bedington	Peak	1,147	7	1%	1,145	100%
	Off Peak	443	0	0%	443	100%
Bedington - Harmony	Peak	1,523	0	0%	1,523	100%
	Off Peak	427	0	0%	427	100%
Elrama - Mitchell	Peak	364	128	35%	326	90%
	Off Peak	657	136	21%	630	96%
Meadow Brook	Peak	847	0	0%	847	100%
	Off Peak	273	2	1%	271	99%
Mount Storm	Peak	705	422	60%	405	57%
	Off Peak	928	440	47%	632	68%
Mount Storm - Pruntytown	Peak	924	620	67%	476	52%
	Off Peak	1,678	1,097	65%	891	53%
Sammis - Wylie Ridge	Peak	1,158	756	65%	624	54%
	Off Peak	4,114	2,754	67%	2,094	51%

Table 2-20 Three pivotal supplier test details for constraints located in the AP Control Zone: Calendar year 2008

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Bedington	Peak	25	6	2	0	2
	Off Peak	25	4	2	0	2
Bedington - Harmony	Peak	11	3	2	0	2
	Off Peak	22	3	2	0	2
Elrama - Mitchell	Peak	27	65	7	2	5
	Off Peak	29	51	5	1	5
Meadow Brook	Peak	31	1	2	0	2
	Off Peak	31	1	2	0	2
Mount Storm	Peak	106	354	13	7	5
	Off Peak	93	264	10	4	6
Mount Storm - Pruntytown	Peak	98	323	11	7	4
	Off Peak	103	324	10	6	4
Sammis - Wylie Ridge	Peak	53	130	16	10	7
	Off Peak	49	122	15	9	6

- **AEP Control Zone Constraints.** In 2008, there were four constraints that occurred for more than 100 hours in the AEP Control Zone. Table 2-21 and Table 2-22 show the results of the three pivotal supplier tests applied to the constraints in the AEP Control Zone. For three of the four constraints, the average number of owners with available supply was two or less. The three pivotal supplier test results reflect this, as the average number of owners that passed is significant only for the Cloverdale – Lexington 500 kV line with the largest number of owners, on average. The Cloverdale – Lexington 500 kV line had more owners and more effective supply and thus a higher percentage of tests with one or more owners that passed.

Table 2-21 Three pivotal supplier results summary for constraints located in the AEP Control Zone: Calendar year 2008

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Carnegie - Tidd	Peak	409	0	0%	409	100%
	Off Peak	353	0	0%	353	100%
Cloverdale - Lexington	Peak	1,044	736	70%	563	54%
	Off Peak	6,167	3,579	58%	3,996	65%
Kammer - Ormet	Peak	564	0	0%	564	100%
	Off Peak	816	0	0%	816	100%
Mahans Lane - Tidd	Peak	531	0	0%	531	100%
	Off Peak	247	0	0%	247	100%

Table 2-22 Three pivotal supplier test details for constraints located in the AEP Control Zone: Calendar year 2008

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Carnegie - Tidd	Peak	10	8	2	0	2
	Off Peak	14	9	1	0	1
Cloverdale - Lexington	Peak	77	266	15	9	6
	Off Peak	82	239	13	6	6
Kammer - Ormet	Peak	28	17	1	0	1
	Off Peak	16	15	1	0	1
Mahans Lane - Tidd	Peak	9	9	1	0	1
	Off Peak	9	10	1	0	1

- **JCPL Control Zone Constraints.** In 2008, the Atlantic – Larrabee 230 kV line was the only constraint in the JCPL Control Zone to occur for more than 100 hours. Table 2-23 and Table 2-24 show the results of the three pivotal supplier tests applied to this constraint. The average number of owners with available supply was four on peak and three off peak. The three pivotal supplier test results reflect this, as 97 percent of the tests applied on peak and 100 percent of the tests applied off peak resulted in one or more owners failing the test.

Table 2-23 Three pivotal supplier results summary for constraints located in the JCPL Control Zone: Calendar year 2008

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Atlantic - Larrabee	Peak	679	212	31%	656	97%
	Off Peak	632	9	1%	630	100%

Table 2-24 Three pivotal supplier test details for constraints located in the JCPL Control Zone: Calendar year 2008

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Atlantic - Larrabee	Peak	23	42	4	1	4
	Off Peak	25	27	3	0	3

- **PENELEC Control Zone Constraints.** In 2008, there were three constraints in the PENELEC Control Zone that occurred for more than 100 hours in the PENELEC Control Zone. Table 2-25 and Table 2-26 show the results of the three pivotal supplier tests applied to the constraints in the PENELEC Control Zone. The average number of owners with available supply was three on peak and three off peak for the East Towanda transformer and the Homer City – Shelocta 230 kV line, and one on peak and one off peak for the Garman – Westover 115 kV line. The three pivotal supplier test results reflect this, as nearly all tests were failed.

Table 2-25 Three pivotal supplier results summary for constraints located in the PENELEC Control Zone: Calendar year 2008

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
East Towanda	Peak	1,361	35	3%	1,353	99%
	Off Peak	452	1	0%	452	100%
Garman - Westover	Peak	628	0	0%	628	100%
	Off Peak	779	0	0%	779	100%
Homer City - Shelocta	Peak	319	4	1%	316	99%
	Off Peak	327	4	1%	326	100%

Table 2-26 Three pivotal supplier test details for constraints located in the PENELEC Control Zone: Calendar year 2008

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
East Towanda	Peak	19	5	3	0	2
	Off Peak	8	4	3	0	3
Garman - Westover	Peak	10	5	1	0	1
	Off Peak	6	6	1	0	1
Homer City - Shelocta	Peak	23	73	3	0	3
	Off Peak	24	57	3	0	3

- **Dominion Control Zone Constraints.** In 2008, there were four constraints in the Dominion Control Zone that occurred for more than 100 hours. Table 2-27 and Table 2-28 show the results of the three pivotal supplier test applied to the constraints in the Dominion Control Zone. The average number of owners with available supply was one on peak and one off peak for the Beechwood – Kerr Dam and the Halifax – Mount Laurel 115 kV lines. The average number of owners with available supply was four on peak and five or less off peak for the Clover transformer and the Danville – East Danville 138 kV line. The three pivotal supplier test results reflect this, as nearly all tests were failed.

Table 2-27 Three pivotal supplier results summary for constraints located in the Dominion Control Zone: Calendar year 2008

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Beechwood - Kerr Dam	Peak	457	0	0%	457	100%
	Off Peak	70	0	0%	70	100%
Clover	Peak	321	144	45%	321	100%
	Off Peak	2	0	0%	2	100%
Danville - East Danville	Peak	87	9	10%	85	98%
	Off Peak	415	5	1%	415	100%
Halifax - Mount Laurel	Peak	444	31	7%	413	93%
	Off Peak	455	30	7%	425	93%

Table 2-28 Three pivotal supplier test details for constraints located in the Dominion Control Zone: Calendar year 2008

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Beechwood - Kerr Dam	Peak	5	3	1	0	1
	Off Peak	6	4	1	0	1
Clover	Peak	38	106	4	1	3
	Off Peak	10	104	5	0	5
Danville - East Danville	Peak	38	31	4	0	3
	Off Peak	30	27	2	0	2
Halifax - Mount Laurel	Peak	9	3	1	0	1
	Off Peak	13	3	1	0	1

- **DPL Control Zone Constraints.** In 2008, the Keeney At5n transformer and the North Seaford – Pine Street 69 kV line were the two constraints in the DPL Control Zone to occur for more than 100 hours. Table 2-29 and Table 2-30 show the results of the three pivotal supplier test applied to the two constraints. The average number of owners with available supply was five on peak and four off peak for the Keeney At5n transformer and two on peak and two off peak for the North Seaford – Pine Street 69 kV line. The three pivotal supplier test results reflect this, as nearly all tests were failed.

Table 2-29 Three pivotal supplier results summary for constraints located in the DPL Control Zone: Calendar year 2008

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Keeney At5n	Peak	304	64	21%	284	93%
	Off Peak	196	24	12%	191	97%
North Seaford - Pine Street	Peak	255	0	0%	255	100%
	Off Peak	145	0	0%	145	100%

Table 2-30 Three pivotal supplier test details for constraints located in the DPL Control Zone: Calendar year 2008

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Keeney At5n	Peak	28	121	5	1	4
	Off Peak	31	126	4	0	4
North Seaford - Pine Street	Peak	3	20	2	0	2
	Off Peak	3	18	2	0	2

- **AECO Control Zone Constraints.** In 2008, there were three constraints in the AECO Control Zone that occurred for more than 100 hours. Table 2-31 and Table 2-32 show the results of the three pivotal supplier test applied to the constraints in the AECO Control Zone. The average number of owners with available supply was one. The three pivotal supplier test results reflect this, as all tests were failed.

Table 2-31 Three pivotal supplier results summary for constraints located in the AECO Control Zone: Calendar year 2008

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Churchtown	Peak	170	0	0%	170	100%
	Off Peak	53	0	0%	53	100%
Monroe	Peak	1,132	0	0%	1,132	100%
	Off Peak	284	0	0%	284	100%
Quinton - Roadstown	Peak	80	0	0%	80	100%
	Off Peak	35	0	0%	35	100%

Table 2-32 Three pivotal supplier test details for constraints located in the AECO Control Zone: Calendar year 2008

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Churchtown	Peak	11	10	1	0	1
	Off Peak	15	10	1	0	1
Monroe	Peak	17	6	1	0	1
	Off Peak	14	4	1	0	1
Quinton - Roadstown	Peak	2	4	1	0	1
	Off Peak	2	6	1	0	1

- **DLCO Control Zone Constraints.** In 2008, three constraints in the DLCO Control Zone experienced more than 100 hours of congestion. Table 2-33 and Table 2-34 show the results of the three pivotal supplier test applied to the constraints in the DLCO Control Zone. The average number of owners with available supply was one on peak and one off peak for the Cheswick – Logans Ferry and the Cheswick – Universal 138 kV lines and two on peak and two off peak for the Cheswick – Evergreen 138 kV line. The three pivotal supplier test results reflect this, as all tests were failed.

Table 2-33 Three pivotal supplier results summary for constraints located in the DLCO Control Zone: Calendar year 2008

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Cheswick - Evergreen	Peak	170	0	0%	170	100%
	Off Peak	26	0	0%	26	100%
Cheswick - Logans Ferry	Peak	283	0	0%	283	100%
	Off Peak	157	0	0%	157	100%
Cheswick - Universal	Peak	163	0	0%	163	100%
	Off Peak	34	0	0%	34	100%

Table 2-34 Three pivotal supplier test details for constraints located in the DLCO Control Zone: Calendar year 2008

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Cheswick - Evergreen	Peak	12	47	2	0	2
	Off Peak	13	36	2	0	2
Cheswick - Logans Ferry	Peak	8	25	1	0	1
	Off Peak	8	30	1	0	1
Cheswick - Universal	Peak	16	92	1	0	1
	Off Peak	19	94	1	0	1

- **ComEd Control Zone Constraints.** In 2008, there were three constraints that occurred for more than 100 hours in the ComEd Control Zone. Table 2-35 and Table 2-36 show the results of the three pivotal supplier tests applied to the constraints in the ComEd Control Zone. The average number of owners with available supply was one for the Cherry Valley transformer and three for the Crete – East Frankfort 345 kV line. The average number of owners with available supply was three on peak and ten off peak for the Burnham – Munster 345 kV line. The three pivotal supplier test results reflect this, as the average number of owners that passed is significant only during off-peak periods for the Burnham – Munster 345 kV line with the largest number of owners and more effective supply, on average.

Table 2-35 Three pivotal supplier results summary for constraints located in the ComEd Control Zone: Calendar year 2008

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Burnham - Munster	Peak	378	13	3%	366	97%
	Off Peak	633	223	35%	451	71%
Cherry Valley	Peak	117	0	0%	117	100%
	Off Peak	15	0	0%	15	100%
Crete - East Frankfort	Peak	18	0	0%	18	100%
	Off Peak	2,262	59	3%	2,238	99%

Table 2-36 Three pivotal supplier test details for constraints located in the ComEd Control Zone: Calendar year 2008

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Burnham - Munster	Peak	304	54	3	1	3
	Off Peak	220	120	10	6	5
Cherry Valley	Peak	10	15	1	0	1
	Off Peak	21	9	1	0	1
Crete - East Frankfort	Peak	54	62	3	0	3
	Off Peak	49	37	3	0	3

- **PECO Control Zone Constraints.** In 2008, the Graceton – Peach Bottom 230 kV line was the only constraint in the PECO Control Zone to occur for more than 100 hours. Table 2-37 and Table 2-38 show the results of the three pivotal supplier test applied to this constraint. The average number of owners with available supply was ten on peak and ten off peak. The three pivotal supplier test results reflect this, as 61 percent of the tests showed one or more owners failing.

Table 2-37 Three pivotal supplier results summary for constraints located in the PECO Control Zone: Calendar year 2008

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Graceton - Peach Bottom	Peak	138	93	67%	84	61%
	Off Peak	492	269	55%	300	61%

Table 2-38 Three pivotal supplier test details for constraints located in the PECO Control Zone: Calendar year 2008

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Graceton - Peach Bottom	Peak	26	73	10	6	5
	Off Peak	25	59	10	5	5

- **Pepco Control Zone Constraints.** In 2008, the Dickerson – Plesant View 230 kV line was the only constraint in the Pepco Control Zone to occur for more than 100 hours. Table 2-39 and Table 2-40 show the results of the three pivotal supplier test applied to this constraint. The average number of owners with available supply was 16 on peak and 14 off peak. The three pivotal supplier test results reflect this, as 39 percent of the tests during on-peak periods and 40 percent of the tests during off-peak periods showed one or more owners failing.

Table 2-39 Three pivotal supplier results summary for constraints located in the Pepco Control Zone: Calendar year 2008

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Dickerson - Plesant View	Peak	592	472	80%	232	39%
	Off Peak	215	171	80%	86	40%

Table 2-40 Three pivotal supplier test details for constraints located in the Pepco Control Zone: Calendar year 2008

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Dickerson - Plesant View	Peak	61	240	16	13	4
	Off Peak	57	213	14	10	4

Market Performance: Markup

The markup index is a summary measure of the behavior or conduct of individual marginal units. However the markup conduct measure does not explicitly capture the impact of this 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.[20]

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 marginal cost. Thus the results do not reflect a counterfactual market outcome based on the assumption that all units made all offers at 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 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 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 calculates an explicit measure of the impact of marginal unit markups on LMP. The markup impact includes the maximum 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.

Markup by System Price Levels

The price component measure uses load-weighted, price-based LMP and load-weighted LMP computed using cost-based offers for all marginal units. The markup component of price is computed by calculating the system price, based on the cost-based offers of the marginal units and comparing that to the actual system price to determine how much of the LMP can be attributed to markup.

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

Table 2-41 shows the average markup component of observed price when the PJM system LMP was in the identified price range.

Table 2-41 Average markup component (By price category): Calendar year 2008

	Average Markup Component	Frequency
Below $20	($4.66)	2.5%
$20 to $39.99	($4.60)	22.0%
$40 to $59.99	($1.11)	31.2%
$60 to $79.99	$2.43	17.7%
$80 to $99.99	$5.09	10.1%
$100 to $119.99	$7.31	7.0%
$120 to $139.99	$10.89	3.9%
$140 to $159.99	$12.64	2.4%
Above $160	$20.73	3.1%

Frequently Mitigated Unit and Associated Unit Adders – Component of Price

On January 25, 2005, the FERC ordered that frequently offer-capped units be provided additional compensation as a form of scarcity pricing, consistent with a recommendation of the MMU.[21] A frequently mitigated unit (FMU) was defined to be a unit that was offer capped for 80 percent or more of its run hours during the prior calendar year. FMUs were allowed either a $40 adder to their cost-based offers in place of the 10 percent adder, or the unit-specific, going-forward costs of the affected unit as a cost-based offer.

In the second half of 2005, discussions were held regarding scarcity pricing and local market power mitigation that led to a settlement agreement accepted by the FERC on January 27, 2006.[22] The settlement agreement revised the definition of FMUs to provide for a set of graduated adders associated with increasing levels of offer capping.[23] Units capped for 60 percent or more of their run hours and less than 70 percent are entitled to an adder of either 10 percent of their cost-based offer or $20 per MWh. Units capped 70 percent or more of their run hours and less than 80 percent are entitled to an adder of either 15 percent of their cost-based offer (not to exceed $40) or $30 per MWh. Units capped 80 percent or more of their run hours are entitled to an adder of $40 per MWh or the unit-specific, going-forward costs of the affected unit as a cost-based offer.[24] These categories are designated Tier 1, Tier 2 and Tier 3, respectively.

The settlement agreement further amended the OA to designate associated units (AUs), also at the recommendation of the MMU. An AU is a unit that is electrically and economically identical to an FMU, but does not qualify for the same adder. The settlement agreement provides for monthly

21 110 FERC ¶ 61,053 (2005).
22 114 FERC ¶ 61, 076 (2006).
23 *PJM Interconnection, L.L.C.*, Settlement Agreement, Docket Nos. EL03-236-006, EL04-121-000 (consolidated) (November 16, 2005).
24 OA, Fifth Revised Sheet No. 131B (Effective July 3, 2007).

designation of FMUs and AUs, where a unit's capping percentage is based on a rolling 12-month average, effective with a one-month lag.[25]

For example, if a generating station had two identical units, 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, 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.

As another example, if a generating station had two identical units, 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 72 percent of its run hours, that unit would be eligible for a Tier 2 FMU adder. However, the second unit is an AU to the first unit and would, therefore, be eligible for the higher Tier 3 adder.

Table 2-42 shows the number of FMUs and AUs in each month of 2008. For example, in December 2008, there were 28 FMUs and AUs in Tier 1, 51 FMUs and AUs in Tier 2, and 61 FMUs and AUs in Tier 3.

Table 2-42 Frequently mitigated units and associated units (By month): Calendar year 2008

	FMUs and AUs			Total Eligible
	Tier 1	Tier 2	Tier 3	for Any Adder
January	19	15	69	103
February	30	12	81	123
March	27	21	75	123
April	26	26	72	124
May	23	25	76	124
June	27	26	75	128
July	27	28	73	128
August	28	37	63	129
September	18	45	53	116
October	31	35	61	127
November	36	30	64	130
December	28	51	61	140

Table 2-43 shows the number of months FMUs and AUS were eligible for any adder (Tier 1, Tier 2 or Tier 3) during 2008. Of the 171 units eligible in at least one month during 2008, 114 units (67 percent) were FMUs or AUs for more than eight months. Approximately half of the units (74 units or 43 percent) were eligible every month during the year. This demonstrates that the group of FMUs and AUs is fairly stable, although units may move between the tier levels, month-to-month.

25 OA, Fifth Revised Sheet No. 132 (Effective July 3, 2007). In 2007, the FERC approved OA revisions to clarify the AU criteria.

Table 2-43 Frequently mitigated units and associated units total months eligible: Calendar year 2008

Months Adder-Eligible	FMU & AU Count
1	16
2	15
3	8
4	3
5	3
6	3
7	4
8	5
9	2
10	13
11	25
12	74
Total	171

FMU and AU adders contributed $.30 per MWh to system average LMP in 2008, out of a real-time, load weighted LMP of $71.13 per MWh.

Market Performance: Load and LMP

The PJM system load and LMP reflect the configuration of the entire RTO. The PJM Energy Market includes the Real-Time Energy Market, which started on January 1, 1998, and the Day-Ahead Energy Market, which started on June 1, 2000.

Load

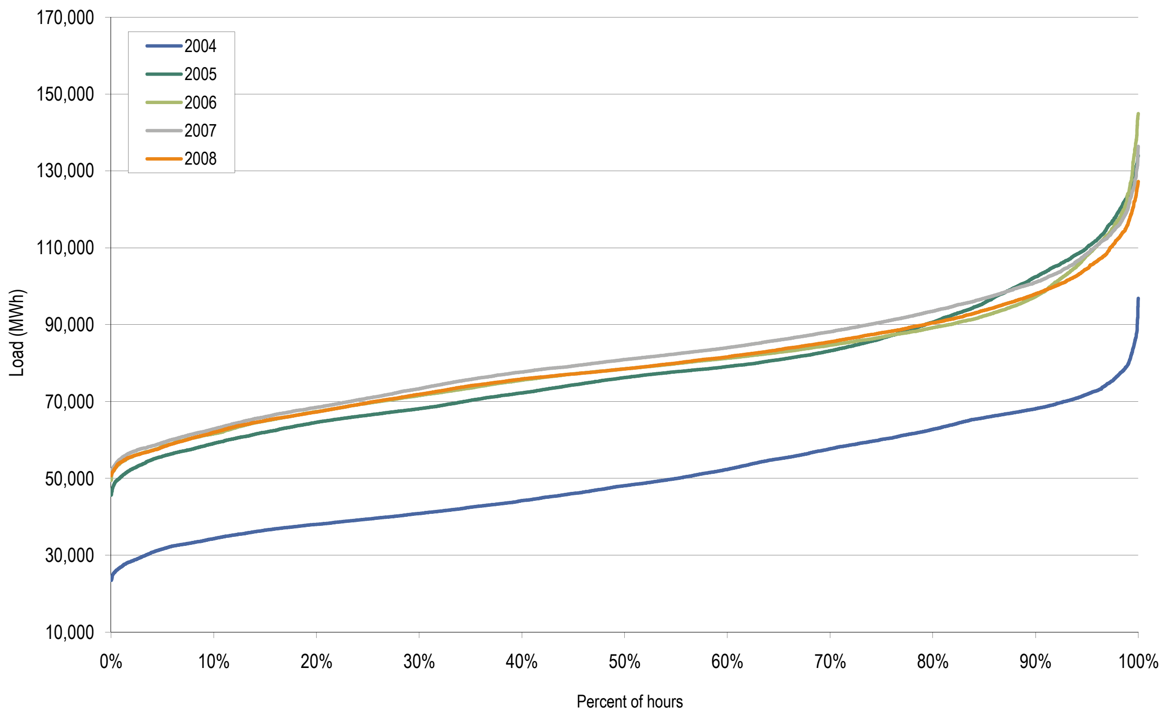
Real-Time Load

PJM real-time load is the total hourly accounting load in real time.[26]

PJM Real-Time Load Duration

Figure 2-4 shows PJM real-time load duration curves from 2004 to 2008. A load duration curve shows the percent of hours that load was at, or below, a given level for the year.

Figure 2-4 PJM real-time load duration curves: Calendar years 2004 to 2008



26 All real-time load data in Section 2, "Energy Market, Part 1," "Market Performance: Load and LMP" are based on PJM accounting load. See the *2008 State of the Market Report*, Volume II, Appendix I, "Load Definitions," for detailed definitions of accounting load.

PJM Real-Time, Annual Average Load

Table 2-44 presents summary real-time load statistics for the 11-year period 1998 to 2008. The average load of 79,515 MWh in 2008 was 2.7 percent lower than the 2007 annual average hourly load. This average load was based on the PJM hourly accounting load. Before June 1, 2007, transmission losses were included in accounting load. After June 1, 2007, transmission losses were excluded from accounting load because of the implementation of marginal loss pricing. The average 2007 load of 81,681 MWh includes losses prior to June 1 but does not include losses after June 1, 2007. If transmission losses had been included, the real-time, annual average load for 2007 would have been 82,857 MWh, which was 4.3 percent higher than the 2006 real-time, annual average hourly load.[27] The average 2008 load of 79,515 does not include losses. If transmission losses had been included, the real-time, annual average load for 2008 would have been 81,442 MWh, which was 2.4 percent higher than the 2008 real-time, annual average hourly load.[28]

Table 2-44 PJM real-time average load: Calendar years 1998 to 2008

	PJM Real-Time Load (MWh)			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	28,578	28,653	5,511	NA	NA	NA
1999	29,641	29,341	5,956	3.7%	2.4%	8.1%
2000	30,113	30,170	5,529	1.6%	2.8%	(7.2%)
2001	30,297	30,219	5,873	0.6%	0.2%	6.2%
2002	35,731	34,746	8,013	17.9%	15.0%	36.4%
2003	37,398	37,031	6,832	4.7%	6.6%	(14.7%)
2004	49,963	48,103	13,004	33.6%	29.9%	90.3%
2005	78,150	76,247	16,296	56.4%	58.5%	25.3%
2006	79,471	78,473	14,534	1.7%	2.9%	(10.8%)
2007	81,681	80,914	14,618	2.8%	3.1%	0.6%
2008	79,515	78,481	13,758	(2.7%)	(3.0%)	(5.9%)

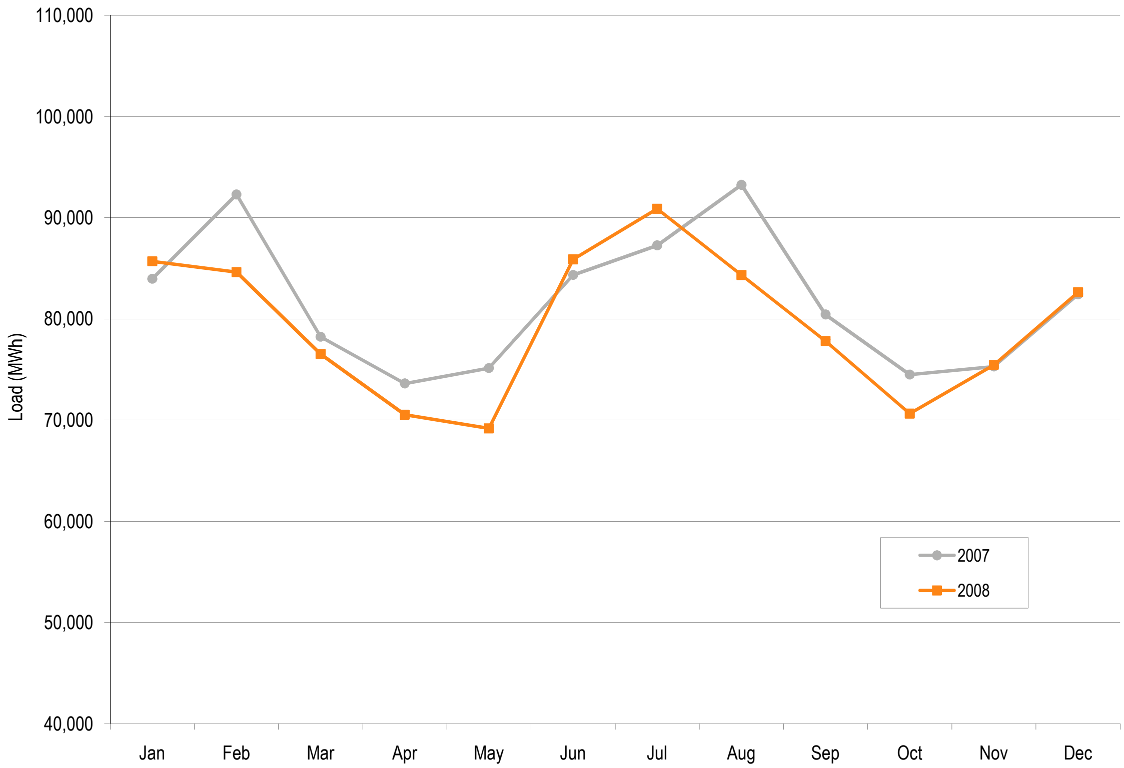
27 Accounting load is used here because PJM uses accounting load in the settlement process, which determines how much load customers pay for. In addition, the use of accounting load with losses before June 1, and without losses after June 1, 2007, is consistent with PJM's calculation of LMP, which excludes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

28 Data quality improvements have caused values in some tables in this section to vary slightly from previously published results.

PJM Real-Time, Monthly Average Load

Figure 2-5 compares the real-time, monthly average hourly loads of 2008 with those of 2007.

Figure 2-5 PJM real-time average load: Calendar years 2007 to 2008



PJM real-time load is significantly affected by temperature. PJM uses the Temperature-Humidity Index (THI) as the weather variable in the PJM load forecast model for the cooling season (June, July and August).[29] THI is a measure of effective temperature using temperature and relative humidity. Table 2-45 shows the monthly minimum, average and maximum of the PJM hourly THI for the cooling months in 2007 and 2008. When comparing 2008 to 2007, changes in THI were mixed, consistent with the changes in load. For the cooling months of 2008, the average THI was 70.71, 0.3 percent lower than the average 71.90 THI for 2007. However, the maximum THI (81.30) and minimum THI (54.94) in 2008 were 1.9 percent lower and 0.9 percent lower, respectively, than the maximum THI (82.84) and minimum THI (55.46) in 2007 during the cooling months.

29 Temperature and relative humidity data that were used to calculate THI were obtained from Meteorlogix. PJM hourly THI is the weighted-average zonal hourly THI weighted by average, annual peak zonal share (Coincident Factor) from 1998 to the year for which the calculation is made. For additional information on THI calculations, see PJM. "Manual 19: Load Forecasting and Analysis" (December 1, 2008), Section 4, pp. 20-21.

Table 2-45 Monthly minimum, average and maximum of PJM hourly THI: Cooling periods of 2007 and 2008

	2007			2008			Difference		
	Min	Avg	Max	Min	Avg	Max	Min	Avg	Max
Jun	55.46	69.18	80.94	54.94	70.16	81.30	(0.9%)	1.4%	0.4%
Jul	55.78	70.92	80.29	62.00	72.25	80.34	11.2%	1.9%	0.1%
Aug	61.60	72.53	82.84	59.89	69.70	78.62	(2.8%)	(3.9%)	(5.1%)

Day-Ahead Load

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

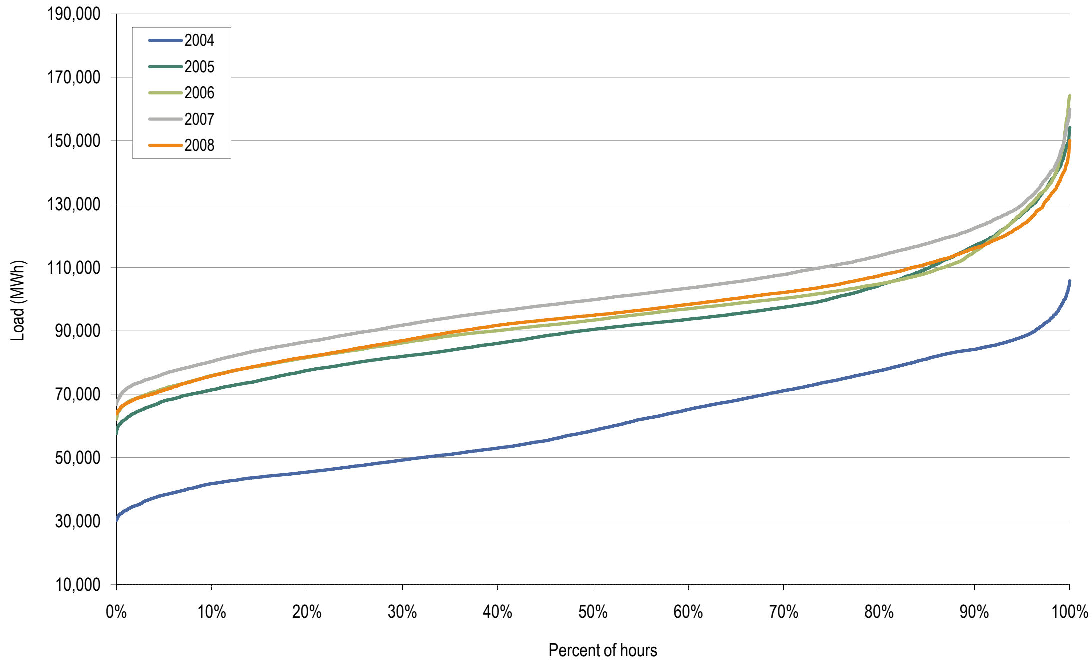
- **Fixed-Demand Bid.** Bid to purchase a defined MWh level of energy, regardless of LMP.
- **Price-Sensitive Bid.** Bid to purchase a defined MWh level of energy only up to a specified LMP, above which the load bid is zero.
- **Decrement Bid (DEC).** Financial bid to purchase a defined MWh level of energy up to a specified LMP, above which the bid is zero. A decrement bid is a financial bid that can be submitted by any market participant.

PJM day-ahead load is the hourly total of the above three types of cleared demand bids.

PJM Day-Ahead Load Duration

Figure 2-6 shows PJM day-ahead load duration curves from 2004 to 2008.

Figure 2-6 PJM day-ahead load duration curves: Calendar years 2004 to 2008



PJM Day-Ahead, Annual Average Load

Table 2-46 presents summary day-ahead load statistics for the five-year period 2004 to 2008. The average load of 95,522 MWh in 2008 was 5.3 percent lower than the 2007 annual average load. The cleared decrement bids, fixed demand and price-sensitive demand in 2008 were 13.3 percent, 3.2 percent and 1.2 percent lower than the corresponding loads in 2007, respectively.

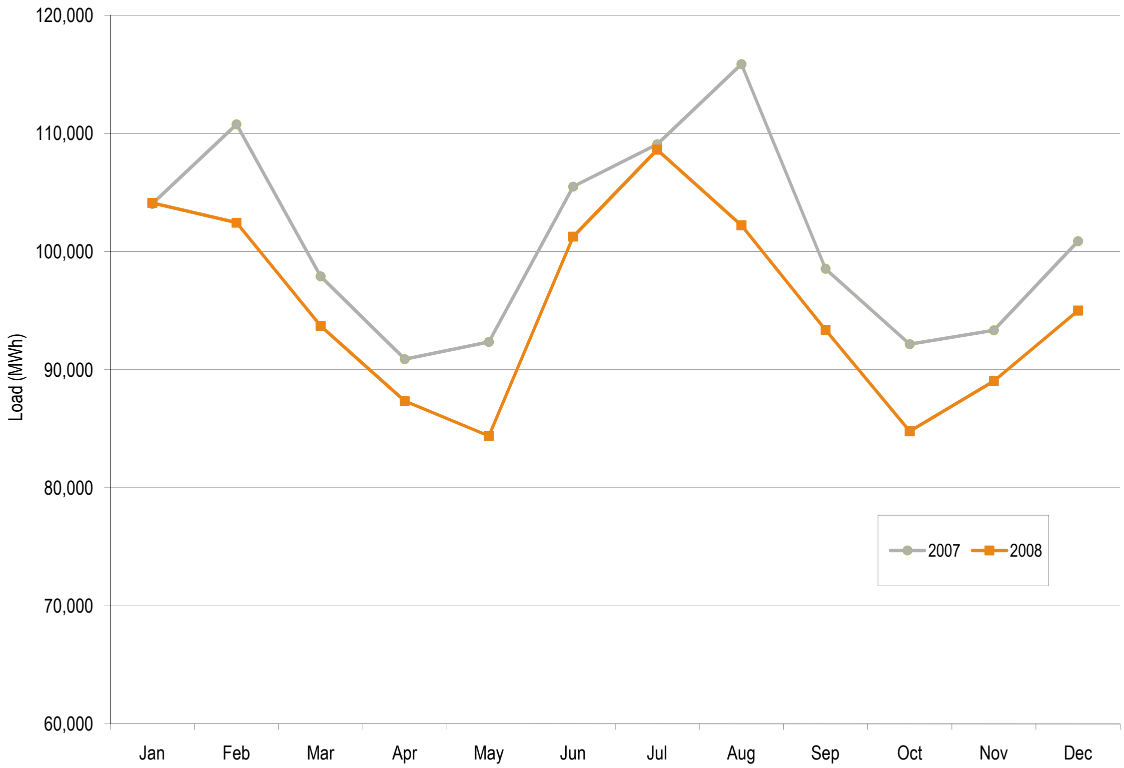
Table 2-46 PJM day-ahead average load: Calendar years 2004 to 2008

	PJM Day-Ahead Load (MWh)			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2004	61,034	58,544	16,318	NA	NA	NA
2005	92,002	90,424	17,381	50.7%	54.5%	6.5%
2006	94,793	93,331	16,048	3.0%	3.2%	(7.7%)
2007	100,912	99,799	16,190	6.5%	6.9%	0.9%
2008	95,522	94,886	15,439	(5.3%)	(4.9%)	(4.6%)

PJM Day-Ahead, Monthly Average Load

Figure 2-7 compares the day-ahead, monthly average loads of 2008 with those of 2007.

Figure 2-7 PJM day-ahead average load: Calendar years 2007 to 2008



Real-Time and Day-Ahead Load

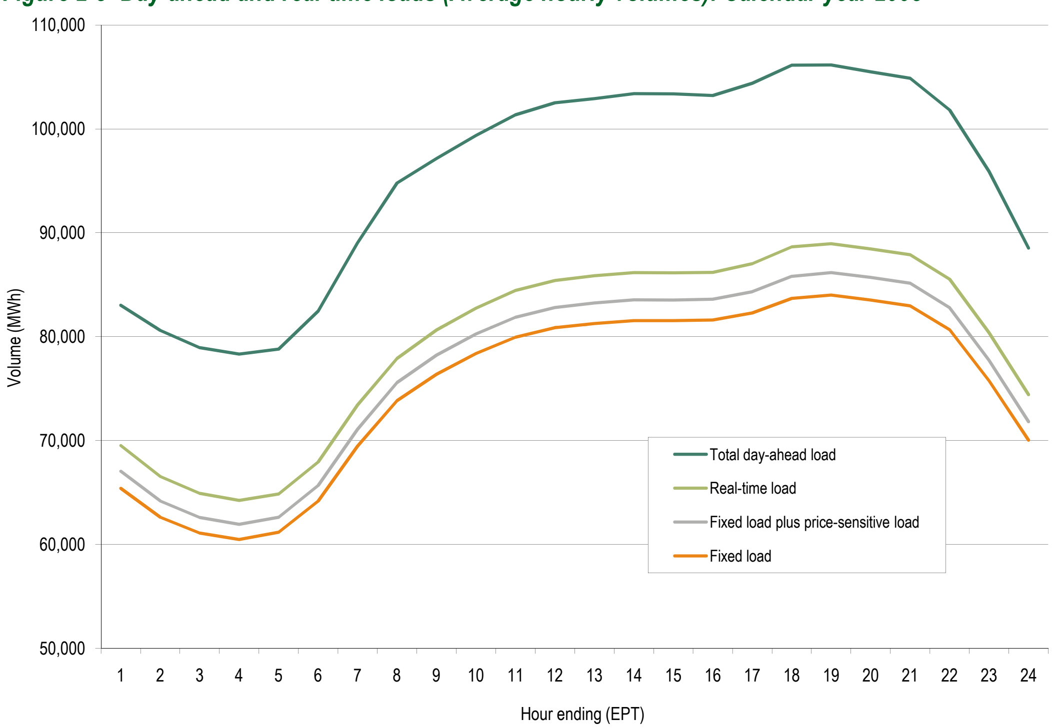
Table 2-47 presents summary statistics for the 2008 day-ahead and real-time loads and the average difference between them. The sum of day-ahead cleared fixed demand and price-sensitive demand averaged 2554 MWh less than real-time average load. Total day-ahead load (the sum of the three types of cleared demand bids) averaged 16,007 MWh more than real-time load. Table 2-47 shows that, at 78.6 percent, fixed demand was the largest component of day-ahead load. At 1.9 percent, price-sensitive load was the smallest component, with cleared decrement bids accounting for the remaining 19.4 percent of day-ahead load.

Table 2-47 Cleared day-ahead and real-time load (MWh): Calendar year 2008

	Day Ahead				Real Time	Average Difference	
	Cleared Fixed Demand	Cleared Price Sensitive	Cleared DEC Bid	Total Load	Total Load	Total Load	Total Load Minus DEC Bid
Average	75,115	1,846	18,561	95,522	79,515	16,007	(2,554)
Median	74,625	1,835	18,306	94,886	78,481	16,405	(1,901)
Standard deviation	12,757	388	2,960	15,439	13,758	1,681	(1,279)

Figure 2-8 shows the average 2008 hourly cleared volumes of fixed-demand bids, the sum of cleared fixed-demand and price-sensitive bids, total day-ahead load and real-time load. During 2008, real-time, hourly average load was higher than cleared fixed-demand load plus cleared price-sensitive load in the Day-Ahead Energy Market, although the reverse was true for 5.1 percent of the hours. When cleared decrement bids are included, day-ahead load always exceeded real-time load.

Figure 2-8 Day-ahead and real-time loads (Average hourly volumes): Calendar year 2008



Real-Time and Day-Ahead Generation

Real-time generation is the actual production of electricity during the operating day.

In the Day-Ahead Energy Market,[30] three types of financially binding generation offers are made and cleared:

- **Self-Scheduled.** Offer to supply a fixed block of MWh that must run from a specific unit, or as a minimum amount of MWh that must run on a specific unit that also has a dispatchable component above the minimum.[31]

- **Generator Offer.** Offer to supply a schedule of MWh from a specific unit and the corresponding offer prices.

- **Increment Offer (INC).** Financial offer to supply specified MWh at, or above, a given price. An increment offer is a financial offer that can be submitted by any market participant.

Table 2-48 presents summary statistics for 2008 day-ahead and real-time generation and the average differences between them. Day-ahead cleared generation from physical units averaged 724 MWh higher than real-time generation. Day-ahead cleared generation plus cleared INC offers averaged 15,626 MWh more than real-time generation. Table 2-48 also shows that cleared generation and INC offers accounted for 85.0 percent and 15.0 percent of day-ahead supply, respectively.

Table 2-48 Day-ahead and real-time generation (MWh): Calendar year 2008

	Day Ahead			Real Time	Average Difference	
	Cleared Generation	Cleared INC Offer	Cleared Generation Plus INC Offer	Generation	Cleared Generation	Cleared Generation Plus INC Offer
Average	84,202	14,902	99,104	83,478	724	15,626
Median	83,466	14,555	98,210	82,223	1,243	15,987
Standard deviation	14,268	2,252	15,558	13,787	481	1,771

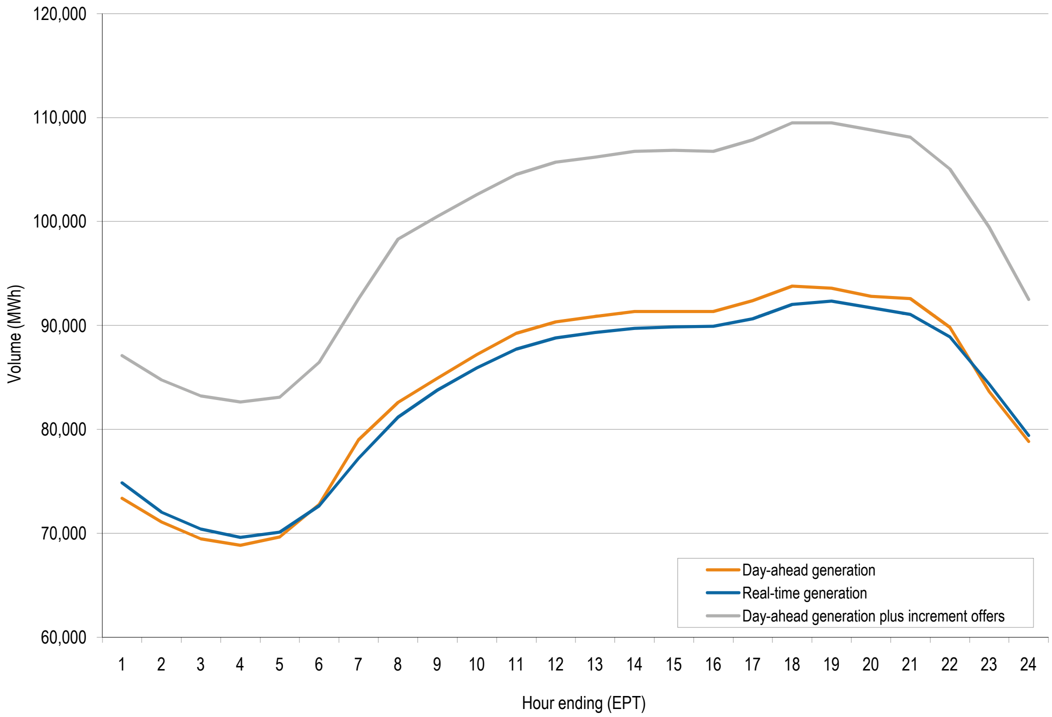
Figure 2-9 shows average hourly cleared volumes of day-ahead generation, day-ahead generation plus increment offers and real-time generation for 2008.[32] Day-ahead generation is all the self-scheduled and generator offers cleared in the Day-Ahead Energy Market. During 2008, real-time, hourly average generation was lower than day-ahead generation from physical units, although the reverse was true for 37.8 percent of the hours. When cleared increment offers are included, average hourly total day-ahead cleared MW offers exceeded real-time generation.

30 All references to day-ahead generation and increment offers are presented in cleared MWh in the "Real-Time and Day-Ahead Generation" portion of the *2008 State of the Market Report,* Volume II, Section 2, "Energy Market, Part 1."

31 The definition of self-scheduled is based on documentation from PJM. "eMKT User Guide" (June 2007), pp. 49-51.

32 Generation data are the sum of MWh at every generation bus in PJM with positive output.

Figure 2-9 Day-ahead and real-time generation (Average hourly volumes): Calendar year 2008



Locational Marginal Price (LMP)

The conduct of individual market entities within a market structure is reflected in market prices. The overall level of prices is a good general indicator of market performance, although overall price results must be interpreted carefully because of the multiple factors that affect them.[33]

Real-Time LMP

Real-time LMP is the hourly LMP for the PJM Real-Time Energy Market.

Real-Time Average LMP

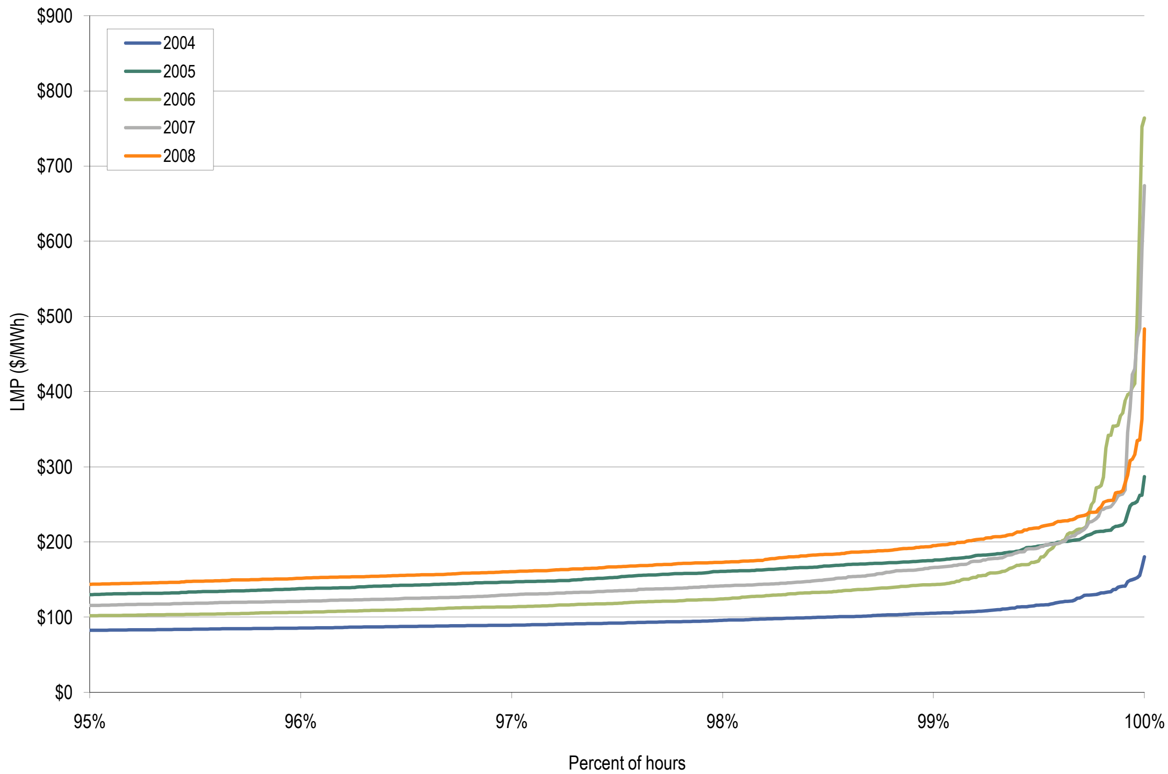
PJM Real-Time LMP Duration

A price duration curve shows the percent of hours when LMP is at, or below, a given price for the year. Figure 2-10 presents price duration curves for hours above the 95th percentile from 2004 to 2008. As Figure 2-10 shows, LMPs were less than $100 per MWh during 95 percent or more of the hours for the year 2004 and less than $150 during 95 percent or more of the hours for the years 2005 to 2008.[34]

33 See the *2008 State of the Market Report*, Volume II, Appendix C, “Energy Market,” for methodological background, detailed price data and comparisons and Appendix H, “Calculating Locational Marginal Price” for more information on how bus LMPs are aggregated to system LMPs.

34 See the *2008 State of the Market Report*, Volume II, Appendix C, “Energy Market.”

Figure 2-10 Price duration curves for the PJM Real-Time Energy Market during hours above the 95th percentile: Calendar years 2004 to 2008



PJM Real-Time, Annual Average LMP

Table 2-49 shows the PJM real-time, annual, simple average LMP for the 11-year period 1998 to 2008.[35] The system simple average LMP for 2008 was 15.3 percent higher than the 2007 annual average, $66.40 per MWh versus $57.58 per MWh.

35 The system annual, simple 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.

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Table 2-49 PJM real-time, simple average LMP (Dollars per MWh): Calendar years 1998 to 2008

	Real-Time LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$21.72	$16.60	$31.45	NA	NA	NA
1999	$28.32	$17.88	$72.42	30.4%	7.7%	130.3%
2000	$28.14	$19.11	$25.69	(0.6%)	6.9%	(64.5%)
2001	$32.38	$22.98	$45.03	15.1%	20.3%	75.3%
2002	$28.30	$21.08	$22.41	(12.6%)	(8.3%)	(50.2%)
2003	$38.28	$30.79	$24.71	35.3%	46.1%	10.3%
2004	$42.40	$38.30	$21.12	10.8%	24.4%	(14.5%)
2005	$58.08	$47.18	$35.91	37.0%	23.2%	70.0%
2006	$49.27	$41.45	$32.71	(15.2%)	(12.1%)	(8.9%)
2007	$57.58	$49.92	$34.60	16.9%	20.4%	5.8%
2008	$66.40	$55.53	$38.62	15.3%	11.2%	11.6%

Zonal Real-Time, Annual Average LMP

Table 2-50 shows PJM zonal real-time, simple average LMP for 2007 and 2008. The largest zonal increase was in the AECO Control Zone which experienced a $15.68, or 24.1 percent, increase over 2007 and the smallest increase was in the ComEd Control Zone which experienced a $3.67 increase, or 8.0 percent, over 2007.

Table 2-50 Zonal real-time, simple average LMP (Dollars per MWh): Calendar years 2007 to 2008

	2007	2008	Difference	Difference as Percent of 2007
AECO	$65.02	$80.70	$15.68	24.1%
AEP	$46.55	$53.42	$6.87	14.7%
AP	$57.45	$65.85	$8.40	14.6%
BGE	$69.79	$80.05	$10.25	14.7%
ComEd	$45.71	$49.38	$3.67	8.0%
DAY	$46.47	$53.68	$7.21	15.5%
DLCO	$43.93	$48.81	$4.88	11.1%
Dominion	$66.75	$75.87	$9.12	13.7%
DPL	$64.15	$77.20	$13.05	20.3%
JCPL	$65.74	$78.80	$13.06	19.9%
Met-Ed	$64.57	$74.70	$10.13	15.7%
PECO	$62.60	$75.07	$12.47	19.9%
PENELEC	$54.80	$63.37	$8.57	15.6%
Pepco	$70.33	$80.45	$10.12	14.4%
PPL	$62.02	$73.35	$11.33	18.3%
PSEG	$65.92	$79.14	$13.22	20.1%
RECO	$64.85	$77.46	$12.61	19.5%

Real-Time, Annual Average LMP by Jurisdiction

Table 2-51 shows the real-time, simple average LMP for all or part of the jurisdictions within the PJM footprint during 2007 and 2008. The largest increase was in New Jersey which experienced a $13.50, or 20.5 percent, increase over 2007, and the smallest increase was in Illinois which experienced a $3.67, or 8.0 percent, increase over 2007.

Table 2-51 Jurisdiction real-time, simple average LMP (Dollars per MWh): Calendar years 2007 to 2008

	2007	2008	Difference	Difference as Percent of 2007
Delaware	$63.44	$76.26	$12.82	20.2%
Illinois	$45.71	$49.38	$3.67	8.0%
Indiana	$46.25	$53.01	$6.76	14.6%
Kentucky	$46.55	$53.80	$7.25	15.6%
Maryland	$69.63	$79.75	$10.12	14.5%
Michigan	$46.82	$54.07	$7.25	15.5%
New Jersey	$65.77	$79.27	$13.50	20.5%
North Carolina	$62.62	$71.69	$9.07	14.5%
Ohio	$45.69	$52.64	$6.95	15.2%
Pennsylvania	$58.76	$68.98	$10.22	17.4%
Tennessee	$47.32	$54.36	$7.04	14.9%
Virginia	$63.91	$73.20	$9.29	14.5%
West Virginia	$48.50	$55.02	$6.52	13.4%
District of Columbia	$70.25	$80.57	$10.32	14.7%

Hub Real-Time, Annual Average LMP

Table 2-52 shows the real-time, simple average LMPs at the PJM hubs for 2007 and 2008. Hub prices are average LMPs across a defined set of buses, created to provide market participants with trading points that exhibit greater price stability than individual buses. The largest price increase was for the New Jersey Hub which experienced an $13.40, or 20.4 percent, increase over 2007, and the smallest increase was for the Chicago Gen Hub which experienced a $3.49, or 7.7 percent, increase over 2007.

Table 2-52 Hub real-time, simple average LMP (Dollars per MWh): Calendar years 2007 to 2008

	2007	2008	Difference	Difference as Percent of 2007
AEP Gen Hub	$44.14	$50.35	$6.21	14.1%
AEP-DAY Hub	$46.25	$53.05	$6.80	14.7%
Chicago Gen Hub	$45.11	$48.60	$3.49	7.7%
Chicago Hub	$45.76	$49.43	$3.67	8.0%
Dominion Hub	$64.65	$73.89	$9.24	14.3%
Eastern Hub	$63.92	$77.15	$13.23	20.7%
N Illinois Hub	$45.47	$48.99	$3.52	7.7%
New Jersey Hub	$65.62	$79.02	$13.40	20.4%
Ohio Hub	$46.18	$53.09	$6.91	15.0%
West Interface Hub	$51.67	$58.40	$6.73	13.0%
Western Hub	$59.77	$68.53	$8.76	14.7%

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 simple 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 LMPs, each weighted by the PJM total hourly load.

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

Table 2-53 shows the PJM real-time, annual, load-weighted, average LMP for the 11-year period 1998 to 2008. The load-weighted, average system LMP for 2008 was 15.4 percent higher than the 2007 annual, load-weighted, average, $71.13 per MWh versus $61.66 per MWh.

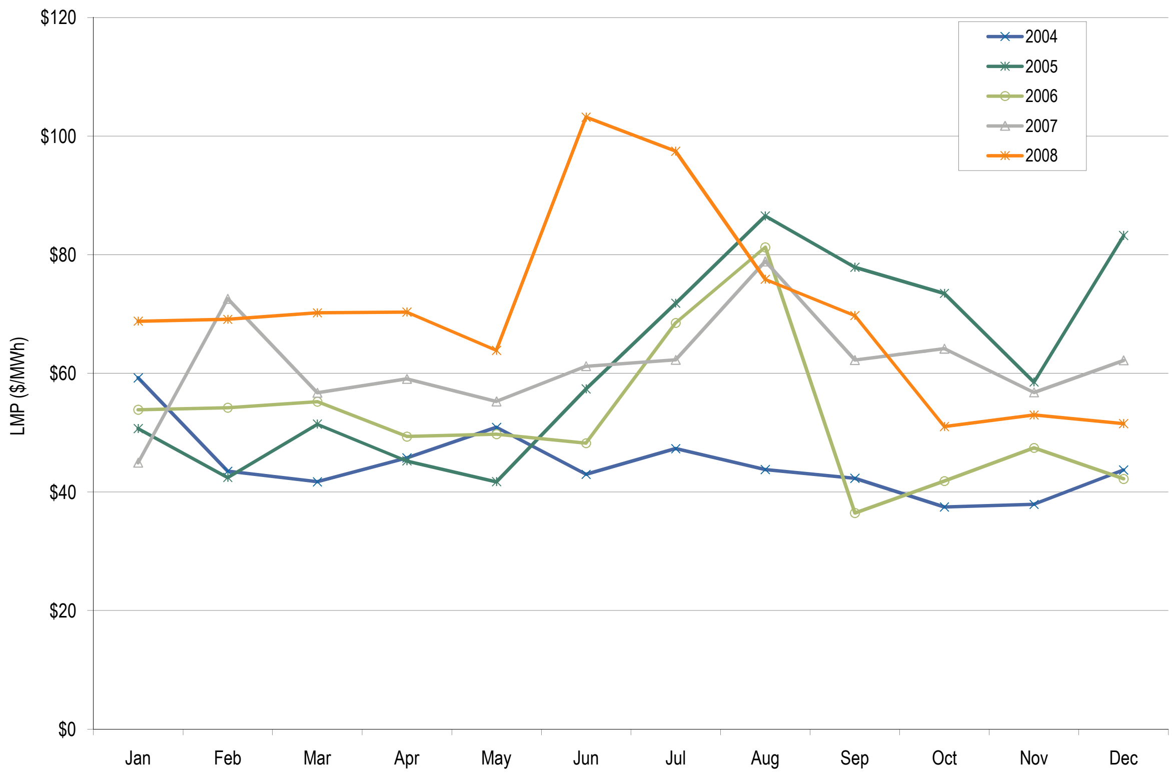
Table 2-53 PJM real-time, annual, load-weighted, average LMP (Dollars per MWh): Calendar years 1998 to 2008

	Real-Time, Load-Weighted, Average LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$24.16	$17.60	$39.29	NA	NA	NA
1999	$34.07	$19.02	$91.49	41.0%	8.1%	132.9%
2000	$30.72	$20.51	$28.38	(9.8%)	7.8%	(69.0%)
2001	$36.65	$25.08	$57.26	19.3%	22.3%	101.8%
2002	$31.60	$23.40	$26.75	(13.8%)	(6.7%)	(53.3%)
2003	$41.23	$34.96	$25.40	30.5%	49.4%	(5.0%)
2004	$44.34	$40.16	$21.25	7.5%	14.9%	(16.3%)
2005	$63.46	$52.93	$38.10	43.1%	31.8%	79.3%
2006	$53.35	$44.40	$37.81	(15.9%)	(16.1%)	(0.8%)
2007	$61.66	$54.66	$36.94	15.6%	23.1%	(2.3%)
2008	$71.13	$59.54	$40.97	15.4%	8.9%	10.9%

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

Figure 2-11 shows the PJM real-time, monthly, load-weighted LMP from 2004 through 2008.

Figure 2-11 PJM real-time, monthly, load-weighted, average LMP: Calendar years 2004 to 2008



Zonal Real-Time, Annual, Load-Weighted, Average LMP

Table 2-54 shows PJM zonal real-time, load-weighted, average LMP for 2007 and 2008. The largest zonal increase was in the AECO Control Zone which experienced a $19.07, or 26.7 percent, increase over 2007, and the smallest increase was in the ComEd Control Zone which experienced a $4.35, or 8.8 percent, increase over 2007.

Table 2-54 Zonal real-time, annual, load-weighted, average LMP (Dollars per MWh): Calendar years 2007 to 2008

	2007	2008	Difference	Difference as Percent of 2007
AECO	$71.48	$90.55	$19.07	26.7%
AEP	$49.60	$56.65	$7.05	14.2%
AP	$61.25	$69.88	$8.63	14.1%
BGE	$75.96	$87.11	$11.15	14.7%
ComEd	$49.28	$53.63	$4.35	8.8%
DAY	$50.08	$57.81	$7.73	15.4%
DLCO	$47.26	$52.45	$5.19	11.0%
Dominion	$72.51	$82.88	$10.37	14.3%
DPL	$69.38	$83.88	$14.50	20.9%
JCPL	$71.90	$86.43	$14.53	20.2%
Met-Ed	$69.36	$79.81	$10.45	15.1%
PECO	$67.14	$80.76	$13.62	20.3%
PENELEC	$57.79	$66.47	$8.68	15.0%
Pepco	$76.74	$87.89	$11.15	14.5%
PPL	$66.13	$77.79	$11.66	17.6%
PSEG	$70.90	$85.54	$14.64	20.6%
RECO	$70.94	$85.26	$14.32	20.2%

Real-Time, Annual, Load-Weighted, Average LMP by Jurisdiction

Table 2-55 shows the real-time, load-weighted, average LMPs for all or part of the jurisdictions within the PJM footprint during 2007 and 2008[36]. The largest increase was in New Jersey which experienced a $15.21, or 21.3 percent, increase over 2007, and the smallest increase was in Illinois which experienced a $4.35, or 8.8 percent, increase over 2007.

Table 2-55 Jurisdiction real-time, annual, load-weighted, average LMP (Dollars per MWh): Calendar years 2007 to 2008

	2007	2008	Difference	Difference as Percent of 2007
Delaware	$68.17	$82.25	$14.08	20.7%
Illinois	$49.28	$53.63	$4.35	8.8%
Indiana	$48.93	$55.98	$7.05	14.4%
Kentucky	$50.20	$57.45	$7.25	14.4%
Maryland	$76.10	$87.10	$11.00	14.5%
Michigan	$50.16	$58.07	$7.91	15.8%
New Jersey	$71.27	$86.48	$15.21	21.3%
North Carolina	$68.03	$80.28	$12.25	18.0%
Ohio	$48.79	$55.90	$7.11	14.6%
Pennsylvania	$62.60	$73.29	$10.69	17.1%
Tennessee	$50.00	$56.67	$6.67	13.3%
Virginia	$69.33	$79.65	$10.32	14.9%
West Virginia	$51.52	$58.21	$6.69	13.0%
District of Columbia	$75.34	$86.68	$11.34	15.1%

Real-Time, Fuel-Cost-Adjusted, Load-Weighted LMP

Fuel Cost

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.[37] To account for the changes in fuel cost between 2007 and 2008, the 2008 load-weighted LMP was adjusted to reflect the change in the daily price of fuels used by marginal units and the change in the amount of load affected by marginal units, using sensitivity factors.[38]

The dominant fuels in PJM all increased in price in 2008. In 2008, the price of 1.5 percent sulfur content per MBtu Central Appalachian coal was 83.0 percent higher than in 2007. The Western

36 The PJM footprint includes 17 control zones. Each control zone is in one or more states or the District of Columbia, but such jurisdictions generally are not entirely covered by PJM control zones. The term jurisdiction is used here to refer to the states in which one or more of these control zones are located. For maps showing the PJM footprint and its control zones, see the *2008 State of the Market Report*, Volume II, Appendix A, "PJM Geography."

37 See the *2008 State of the Market Report*, Volume II, Section 2,"Energy Market, Part 1," at Table 2-32, "Type of fuel used by marginal units: Calendar years 2005 to 2008."

38 For more information, see the *2008 State of the Market Report*, Volume II, Appendix K, "Calculation and Use of Generator Sensitivity Factors."

Rail Powder River Basin coal price was 21.7 percent higher than in 2007. Natural gas prices were 27.0 percent higher in 2008 than in 2007. No. 2 (light) oil prices were 37.9 percent higher and No. 6 (heavy) oil prices were 37.1 percent higher in 2008 than in 2007.

Fuel prices reached their annual peaks in June and July. Since October 2008, the prices for natural gas, light oil and heavy oil were lower than during the corresponding period in 2007. From October to December in 2008, natural gas prices were 6.2 percent lower, No. 2 (light) oil prices were 23.6 percent lower and No. 6 (heavy) oil prices were 36.8 percent lower than the corresponding fuel prices during the same months in 2007. Figure 2-12 shows average, daily delivered coal, natural gas and oil prices for units within PJM.[39]

Figure 2-12 Spot average fuel price comparison: Calendar years 2007 to 2008

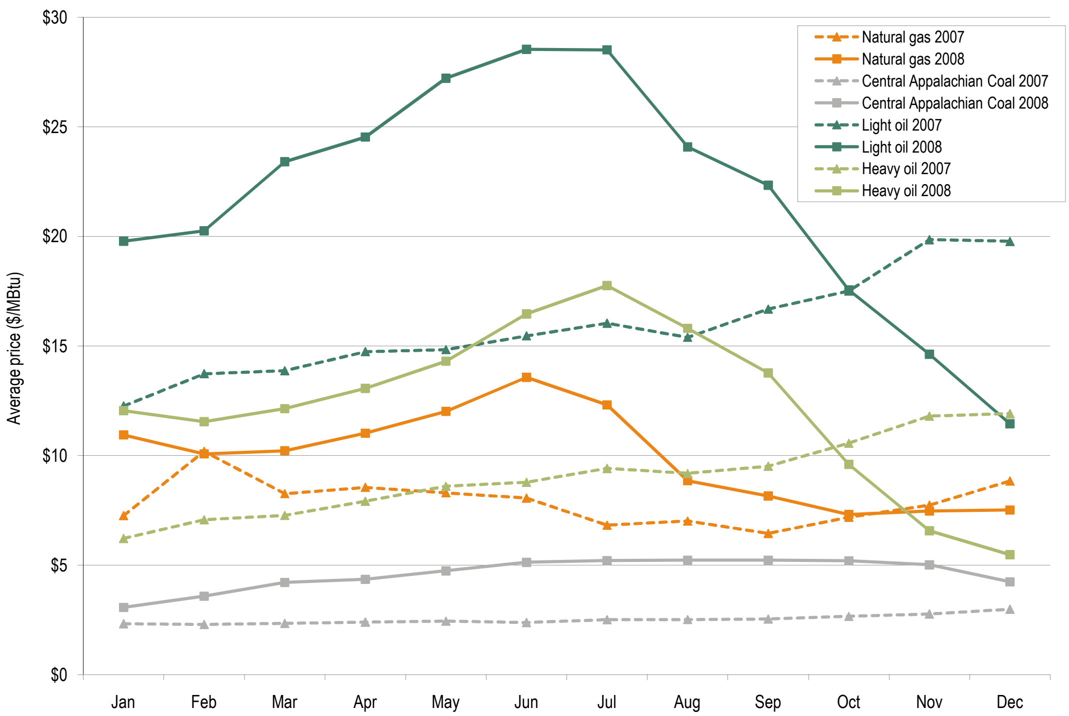


Figure 2-13 shows average, daily settled prices for NO_x and SO_2 emission within PJM. In 2008, NO_x prices were 1.7 percent higher than in 2007. SO_2 prices were 45.9 percent lower in 2008 than in 2007.

The decline in NO_x prices that began in August (Figure 2-13) occurred at about the same time as the issuance of a decision dated August 11, 2008, by the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit) that vacated the Environmental Protection Agency's Clean Air Interstate Rule (CAIR).[40] CAIR required upwind states to implement control measures to

39 Natural gas prices are the daily cash price for Transco-Z6 (non-New York) adjusted for transportation to the burner tip. Light oil prices are the average of the daily price for No. 2 from the New York Harbor Spot Barge and from the Chicago pipeline and are adjusted for transportation. Heavy oil prices are a daily average of New York Harbor Spot Barge for 0.3 percent, 0.7 percent, 1.0 percent, 2.2 percent and 3.0 percent sulfur content. Coal prices are the 1.5 percent sulfur content per MBtu Central Appalachian coal, price-adjusted for transportation. All fuel prices are from Platts.

40 *North Carolina v. Environmental Protection Agency, et al.*, 531 F.3d 896 (2008).

reduce emissions and created an optional interstate cap and trade program for pollutants, including NO_x. Vacatur (as opposed to remand) suspended the existence of the program. The D.C. Circuit reversed its decision en banc on December 23, 2008, remanding CAIR to the EPA for an overhaul, but reinstating the program in the interim.[41]

As a result of the D.C. Circuit's reversal of its decision to vacate CAIR, the EPA implemented the program on schedule. The first phase of CAIR went into effect on January 1, 2009, mandating emissions cuts of NO_x. Mandates for SO_2 emissions will commence on January 1, 2010. The D.C. Circuit's order that that the EPA significantly revise CAIR remains, but there is no deadline.

Figure 2-13 Spot average emission price comparison: Calendar years 2007 to 2008

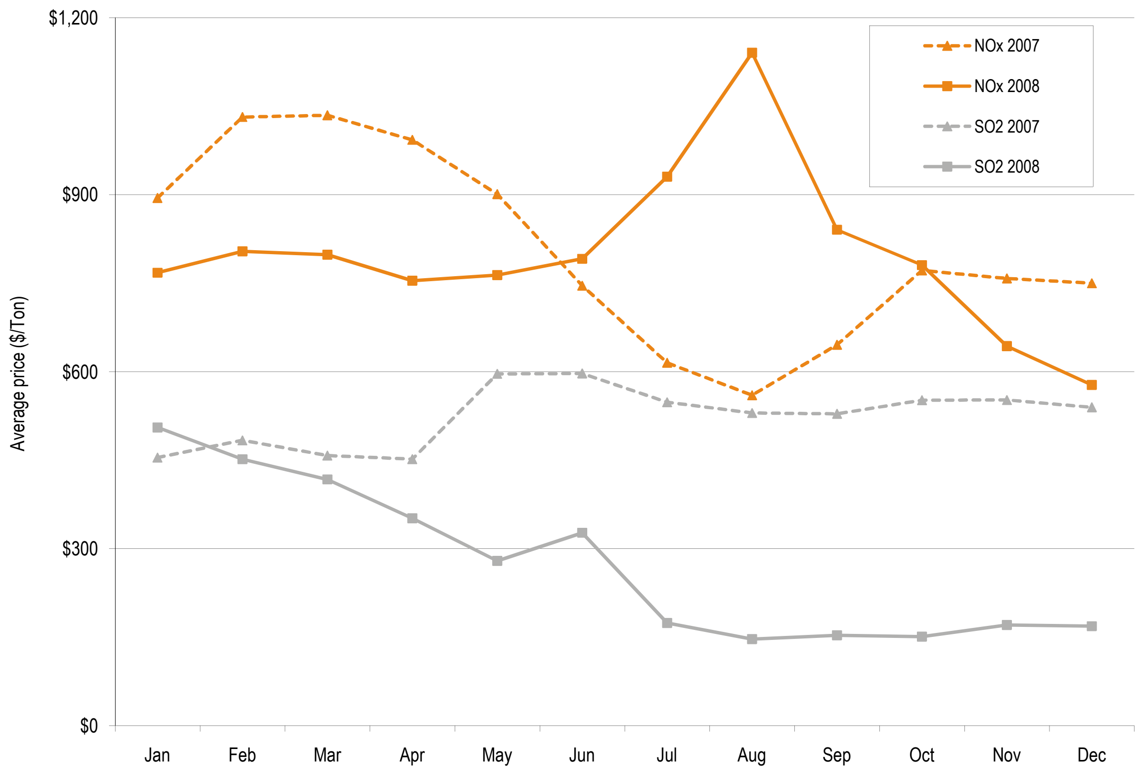


Table 2-56 compares the 2008 PJM fuel-cost-adjusted, load-weighted, average LMP to the 2007 load-weighted, average LMP. The load-weighted, average LMP for 2008 was 15.4 percent higher than the load-weighted, average LMP for 2007. The fuel-cost-adjusted, load-weighted, average LMP in 2008 was 16.0 percent lower than the load-weighted LMP in 2007. If fuel costs for the year 2008 had been the same as for 2007, the 2008 load-weighted LMP would have been lower, $51.79 per MWh instead of $71.13 per MWh. Higher coal, gas and oil prices in 2008 resulted in higher prices in 2008 than would have occurred if fuel prices had remained at their 2007 levels. Net fuel cost increases were the reason for the higher LMPs in 2008.

41 550 F.3d 1176.

Table 2-56 PJM annual, fuel-cost-adjusted, load-weighted LMP (Dollars per MWh): Year-over-year method

	2007 Load-Weighted LMP	2008 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$61.66	$51.79	(16.0%)

Components of Real-Time, Load-Weighted LMP

Observed LMPs result from the operation of a market based on security-constrained, least-cost dispatch in which marginal units generally determine system LMPs, based on their offers. Those offers can be decomposed into fuel costs, emission costs, variable operation and maintenance costs and markup. As a result, it is possible to decompose PJM system LMP using the components of unit offers and sensitivity factors.

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. Spot fuel prices were used, and emission costs were calculated using spot prices for NO_x and SO_2 emission credits and unit-specific emission rates. The emission costs for NO_x are applicable for the May to September ozone season and the emission costs for SO_2 are applicable throughout the year.

Table 2-57 shows that 50.7 percent of the annual, load-weighted LMP was the result of gas costs; 37.2 percent was the result of coal costs and 2.5 percent was the result of the cost of SO_2 emission allowances. Markup was 2.9 percent of LMP. The fuel-related components of LMP reflect the impact of the cost of the identified fuel on LMP rather than the full impact of units burning that fuel on LMP.

As a result of the way in which LMP is calculated, there are differences between the components of LMP associated with individual unit characteristics, e.g. fuel costs and VOM, and observed LMP. This total net difference in 2008 was -$1.77 per MWh. (Numbers in parentheses in the table are negative.) The components of this difference are listed in Table 2-57.[42]

42 The technical reasons for each of these components are explained in the *2008 State of the Market Report*, Volume II, Appendix K, "Calculation and Use of Generator Sensitivity Factors."

Table 2-57 Components of PJM annual, load-weighted, average LMP: Calendar year 2008

Element	Contribution to LMP	Percent
Gas	$36.03	50.7%
Coal	$26.44	37.2%
Oil	$2.56	3.6%
Uranium	$0.00	0.0%
FMU Adder	$0.30	0.4%
SO2	$1.80	2.5%
NOX	$0.72	1.0%
VOM	$3.00	4.2%
Markup	$2.04	2.9%
Offline CT Adder	$0.34	0.5%
UDS Override Differential	($1.79)	(2.5%)
Dipatch Differential	$0.03	0.0%
Small DFAX adjustment	($0.20)	(0.3%)
Flow violation adjustment	$0.01	0.0%
Unit LMP Differential	($0.27)	(0.4%)
NA	$0.12	0.2%
LMP	$71.13	100.0%

PJM Retroactively Changed Real-Time LMP for September 4, 2008

On September 24, 2008, PJM retroactively changed Real-Time, LMP for September 4, 2008, for hours ending 15 through 21 and the hour ending 24, and notified PJM members by email:[43]

> The data file containing the real-time LMP for September 4th, 2008 has been reposted. After review of this data, PJM identified several units that were incorrectly logged on their price-based schedule that should have been offer-capped based on market power mitigation rules specified in the Tariff. These units then set price in real-time which caused incorrect LMP prices in several hours on this day. PJM has corrected these logging mistakes, recalculated, and reposted Real-Time LMPs for hours where this occurred. The only hours affected are hours ending 15 through 21, and 24 on September 4th, 2008. In addition, all settlement reports posted in the MSRS system for this day will be updated as soon as possible to reflect the change in Real-Time LMPs.

Table 2-58 shows zonal, real-time, simple average LMPs for the affected hours before and after the changes. The largest positive zonal impact occurred in the Dominion Control Zone, which experienced an average $2.43 per MWh increase as a result of the change, and the smallest positive zonal impact occurred in the PPL Control Zone which experienced an average $0.13 per MWh increase as a result of the change. The largest negative zonal impact occurred in the PECO

43 The email was sent to PJM-MRC at Wednesday, September 24, 2008 11:18 AM. The subject of the message is “Real-time LMP File Posting Update - September 4, 2008 Real-time Prices – Corrected.”

Control Zone, which experienced an average $2.28 per MWh decrease as a result of the change, and the smallest negative zonal impact occurred in the DPL Control Zone, which experienced an average $0.15 per MWh decrease as a result of the change.

Table 2-58 Zonal average LMP: Hours ending 15 through 21 and hour ending 24

	RT LMP Before Change	RT LMP After Change	Difference	Difference as Percent of LMP Before Change
AECO	$268.97	$268.11	($0.87)	(0.3%)
AEP	$64.03	$63.60	($0.43)	(0.7%)
AP	$140.92	$141.85	$0.93	0.7%
BGE	$178.44	$179.17	$0.73	0.4%
ComEd	$51.10	$50.90	($0.21)	(0.4%)
DAY	$60.83	$60.56	($0.27)	(0.5%)
DLCO	$101.39	$101.86	$0.47	0.5%
Dominion	$141.52	$143.95	$2.43	1.7%
DPL	$265.64	$265.49	($0.15)	(0.1%)
JCPL	$203.45	$202.74	($0.72)	(0.4%)
Met-Ed	$169.36	$167.79	($1.57)	(0.9%)
PECO	$404.47	$402.20	($2.28)	(0.6%)
PENELEC	$125.61	$125.91	$0.30	0.2%
Pepco	$170.50	$171.05	$0.54	0.3%
PPL	$156.12	$156.25	$0.13	0.1%
PSEG	$215.53	$214.71	($0.81)	(0.4%)
RECO	$161.07	$160.72	($0.35)	(0.2%)
PJM	$150.21	$150.20	($0.02)	(0.0%)

Table 2-59 shows the real time, simple average LMPs at the PJM hubs for affected hours before and after the change. The largest positive impact occurred for the Dominion Hub, which experienced an average $3.68 per MWh increase as a result of the changes, and the smallest positive impact occurred for the West Int Hub and Western Hub, which experienced an average $0.60 per MWh decrease as a result of the change. The largest negative impact occurred for the Eastern Hub, which experienced an average $1.12 per MWh decrease as a result of the change, and the smallest negative impact occurred for the Chicago Gen Hub which experienced an average $0.20 decrease as a result of the changes.

Table 2-59 Hub average LMP: Hours ending 15 through 21 and hour ending 24

	RT LMP Before Change	RT LMP After Change	Difference	Difference as Percent of LMP Before Change
AEP GEN HUB	$51.96	$51.70	($0.26)	(0.5%)
AEP-DAYTON HUB	$61.29	$61.03	($0.26)	(0.4%)
CHICAGO GEN HUB	$49.11	$48.90	($0.20)	(0.4%)
CHICAGO HUB	$51.43	$51.22	($0.21)	(0.4%)
DOMINION HUB	$127.17	$130.85	$3.68	2.9%
EASTERN HUB	$323.79	$322.67	($1.12)	(0.3%)
N ILLINOIS HUB	$50.44	$50.23	($0.21)	(0.4%)
NEW JERSEY HUB	$218.14	$217.37	($0.77)	(0.4%)
OHIO HUB	$59.76	$59.53	($0.24)	(0.4%)
WEST INT HUB	$86.74	$87.34	$0.60	0.7%
WESTERN HUB	$145.60	$146.20	$0.60	0.4%

Table 2-60 shows real-time, simple average LMPs at the top ten buses for affected hours before and after the change. The largest positive bus-specific impact occurred at the Mt Laurel 413 KV TX1 bus, in the PSEG Control Zone, which experienced an average $29.86 per MWh increase as a result of the changes, and the largest negative bus-specific impact occurred at the Bonsack 138 KV T1 bus, in the AEP Control Zone, which experienced an average $24.10 decrease as a result of the changes.

Table 2-60 Bus average LMP: Hours ending 15 through 21 and hour ending 24

	RT LMP Before Change	RT LMP After Change	Difference	Difference as Percent of LMP Before Change
BARNJNDP115 KV TX1	$234.36	$258.74	$24.38	10.4%
BLBRANDP69 KV TX1	$204.82	$223.81	$18.99	9.3%
BONSACK 138 KV T1	$112.46	$88.36	($24.10)	(21.4%)
DRYBURG 115 KV TX1	$265.16	$295.01	$29.85	11.3%
DRYBURG 115 KV TX2	$265.16	$295.01	$29.85	11.3%
MTLAURE413 KV TX1	$265.11	$294.97	$29.86	11.3%
NIAGARA212 KV LOAD	$99.68	$89.82	($9.86)	(9.9%)
ROANOKE 138 KV T2	$98.56	$88.70	($9.87)	(10.0%)
VINTON 138 KV T1	$103.67	$88.84	($14.83)	(14.3%)
VINTON 138 KV T2	$103.67	$88.84	($14.83)	(14.3%)

Day-Ahead LMP

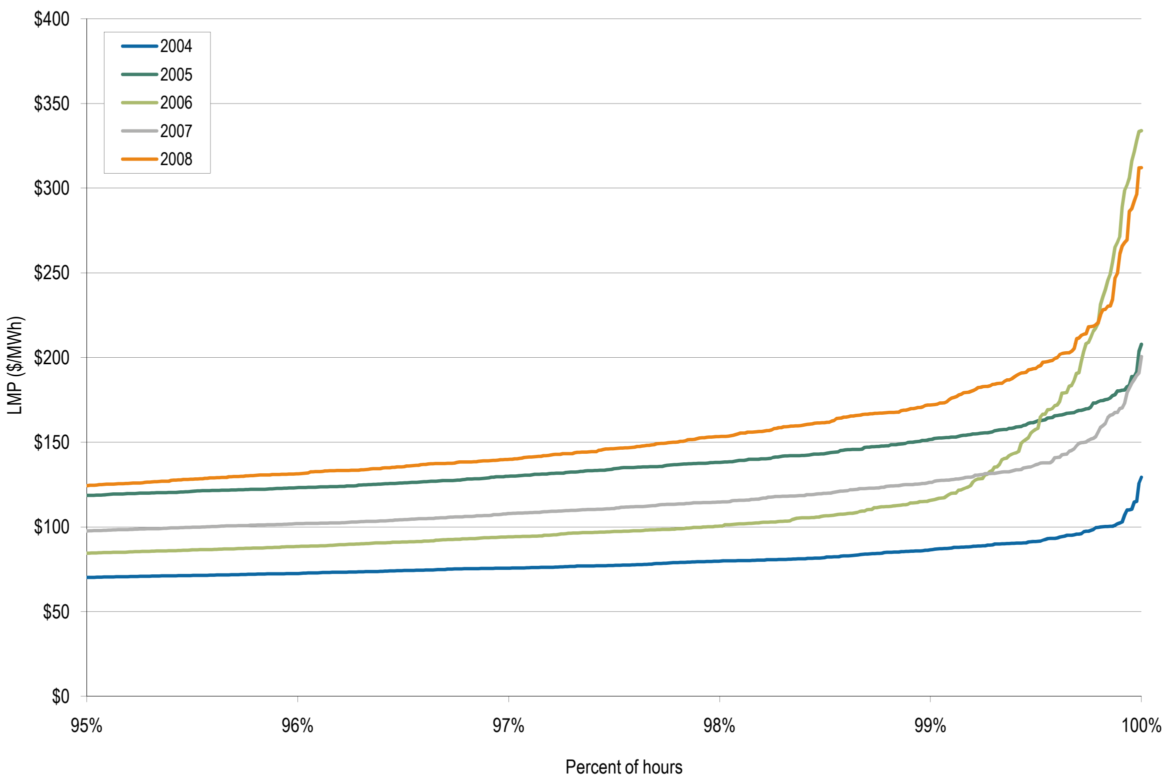
Day-ahead LMP is the hourly LMP for the PJM Day-Ahead Energy Market.

Day-Ahead Average LMP

PJM Day-Ahead LMP Duration

A price duration curve shows the percent of hours when LMP is at, or below, a given price for the year. Figure 2-14 presents day-ahead price duration curves for hours above the 95th percentile from 2004 to 2008. As Figure 2-14 shows, day-ahead LMP was less than $100 per MWh during 95 percent or more of the hours for the years 2004, 2006 and 2007 and less than $150 during 95 percent or more of the hours for 2005 and 2008.

Figure 2-14 Price duration curves for the PJM Day-Ahead Energy Market during hours above the 95th percentile: Calendar years 2004 to 2008



PJM Day-Ahead, Annual Average LMP

Table 2-61 shows the PJM day-ahead annual, simple average LMP for the five-year period 2004 to 2008. The system simple average LMP for 2008 was 20.9 percent higher than the 2007 annual average, $66.12 per MWh versus $54.67 per MWh.

Table 2-61 PJM day-ahead, simple average LMP (Dollars per MWh): Calendar years 2004 to 2008

	Day-Ahead LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2004	$41.43	$40.36	$16.60	NA	NA	NA
2005	$57.89	$50.08	$30.04	39.7%	24.1%	81.0%
2006	$48.10	$44.21	$23.42	(16.9%)	(11.7%)	(22.0%)
2007	$54.67	$52.34	$23.99	13.7%	18.4%	2.4%
2008	$66.12	$58.93	$30.87	20.9%	12.6%	28.7%

Zonal Day-Ahead, Annual Average LMP

Table 2-62 shows PJM zonal day-ahead, simple average LMP for 2007 and 2008. The largest zonal increase was in the JCPL Control Zone which experienced a $16.56, or 26.2 percent, increase over 2007 and the smallest increase was in the ComEd Control Zone which experienced a $5.15, or 11.4 percent, increase over 2007.

Table 2-62 Zonal day-ahead, simple average LMP (Dollars per MWh): Calendar years 2007 to 2008

	2007	2008	Difference	Difference as Percent of 2007
AECO	$62.96	$78.99	$16.03	25.5%
AEP	$45.55	$53.61	$8.06	17.7%
AP	$54.88	$65.09	$10.21	18.6%
BGE	$65.37	$80.70	$15.33	23.5%
ComEd	$45.35	$50.50	$5.15	11.4%
DAY	$45.29	$53.53	$8.24	18.2%
DLCO	$43.75	$50.92	$7.17	16.4%
Dominion	$63.42	$75.60	$12.18	19.2%
DPL	$61.95	$77.95	$16.00	25.8%
JCPL	$63.18	$79.74	$16.56	26.2%
Met-Ed	$61.62	$75.54	$13.92	22.6%
PECO	$61.25	$76.23	$14.98	24.5%
PENELEC	$52.97	$65.11	$12.14	22.9%
Pepco	$66.44	$81.26	$14.82	22.3%
PPL	$60.00	$74.25	$14.25	23.8%
PSEG	$63.94	$79.77	$15.83	24.8%
RECO	$63.37	$78.08	$14.71	23.2%

Day-Ahead, Annual Average LMP by Jurisdiction

Table 2-63 shows PJM's day-ahead, simple average LMPs for 2007 and 2008, by jurisdiction. The largest increase was in New Jersey which experienced a $16.06, or 25.2 percent, increase over 2007, and the smallest increase was in Illinois which experienced a $5.15, or 11.4 percent, increase over 2007.

Table 2-63 Day-ahead, simple average LMP (Dollars per MWh) by state: Calendar years 2007 to 2008

	2007	2008	Difference	Difference as Percent of 2007
Delaware	$61.36	$76.88	$15.52	25.3%
Illinois	$45.35	$50.50	$5.15	11.4%
Indiana	$45.49	$53.58	$8.09	17.8%
Kentucky	$45.42	$53.36	$7.94	17.5%
Maryland	$65.46	$80.01	$14.55	22.2%
Michigan	$46.01	$54.48	$8.47	18.4%
New Jersey	$63.62	$79.68	$16.06	25.2%
North Carolina	$59.91	$71.66	$11.75	19.6%
Ohio	$44.72	$52.85	$8.13	18.2%
Pennsylvania	$56.88	$70.04	$13.16	23.1%
Tennessee	$46.52	$54.24	$7.72	16.6%
Virginia	$61.09	$73.01	$11.92	19.5%
West Virginia	$46.66	$54.67	$8.01	17.2%
District of Columbia	$66.41	$81.04	$14.63	22.0%

Day-Ahead, Load-Weighted, Average LMP

Day-ahead, load-weighted LMP reflects the average LMP paid for day-ahead demand MWh cleared during a year. Day-ahead, load-weighted LMP is the average of PJM day-ahead hourly LMPs, each weighted by the PJM total cleared day-ahead hourly load, including day-ahead fixed load, price-sensitive load and decrement bids.

PJM Day-Ahead, Annual, Load-Weighted, Average LMP

Table 2-64 shows the PJM day-ahead, annual, load-weighted, average LMP for the five-year period 2004 to 2008. The day-ahead, load-weighted, average LMP for 2008 was 21.4 percent higher than the 2007 annual, load-weighted, average, at $70.25 per MWh versus $57.88 per MWh.

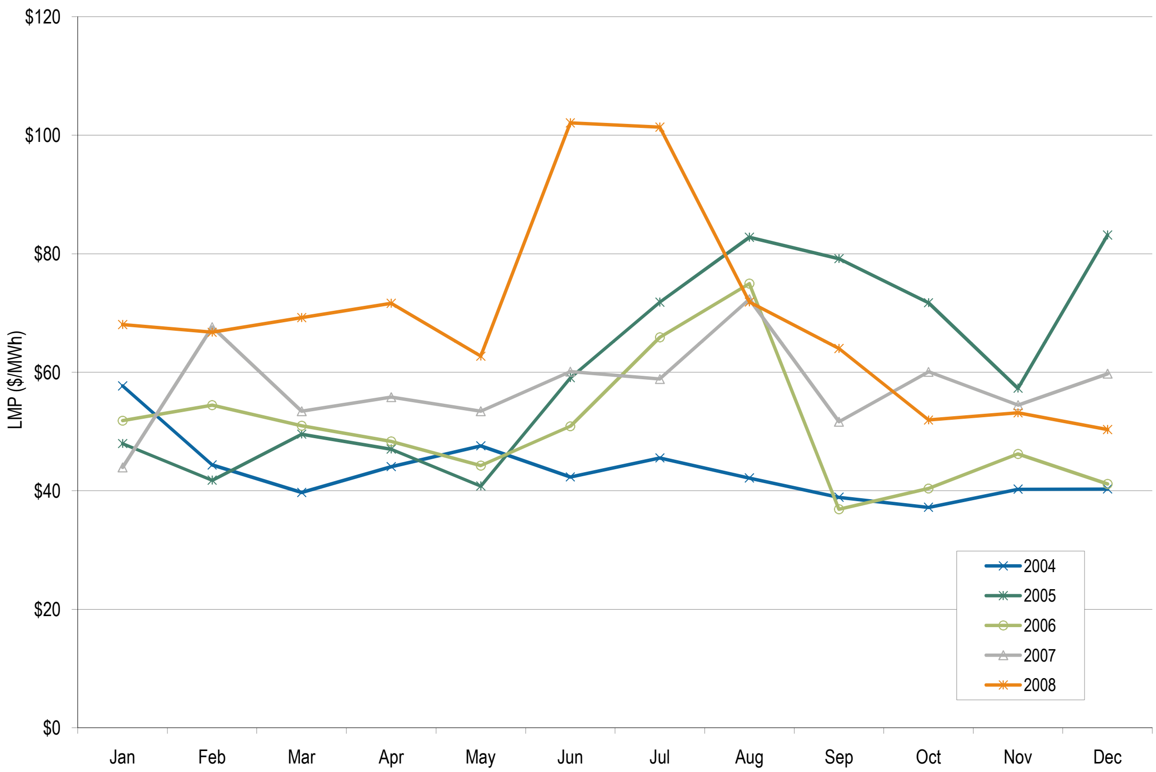
Table 2-64 PJM day-ahead, load-weighted, average LMP (Dollars per MWh): Calendar years 2004 to 2008

	Day-Ahead, Load-Weighted, Average LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2004	$42.87	$41.96	$16.32	NA	NA	NA
2005	$62.50	$54.74	$31.72	45.8%	30.5%	94.4%
2006	$51.33	$46.72	$26.45	(17.9%)	(14.7%)	(16.6%)
2007	$57.88	$55.91	$25.02	12.8%	19.7%	(5.4%)
2008	$70.25	$62.91	$33.14	21.4%	12.5%	32.5%

PJM Day-Ahead, Monthly, Load-Weighted, Average LMP

Figure 2-15 shows the PJM day-ahead, monthly, load-weighted LMP from 2004 through 2008.

Figure 2-15 Day-ahead, monthly, load-weighted, average LMP: Calendar years 2004 to 2008



Zonal Day-Ahead, Annual, Load-Weighted LMP

Table 2-65 shows PJM's zonal day-ahead, load-weighted, average LMPs for 2007 and 2008. The largest zonal increase was in the AECO Control Zone which experienced an $19.66, or 28.4 percent, increase over 2007, and the smallest increase was in the ComEd Control Zone which experienced a $6.56, or 13.9 percent, increase over 2007.

Table 2-65 Zonal day-ahead, load-weighted, average LMP (Dollars per MWh): Calendar years 2007 to 2008

	2007	2008	Difference	Difference as Percent of 2007
AECO	$69.11	$88.77	$19.66	28.4%
AEP	$48.26	$56.48	$8.22	17.0%
AP	$57.34	$67.94	$10.60	18.5%
BGE	$70.22	$87.50	$17.28	24.6%
ComEd	$47.27	$53.83	$6.56	13.9%
DAY	$48.43	$57.04	$8.61	17.8%
DLCO	$46.99	$54.33	$7.34	15.6%
Dominion	$68.08	$81.98	$13.90	20.4%
DPL	$66.84	$84.24	$17.40	26.0%
JCPL	$68.34	$86.65	$18.31	26.8%
Met-Ed	$65.36	$79.88	$14.52	22.2%
PECO	$65.21	$81.44	$16.23	24.9%
PENELEC	$55.44	$67.56	$12.12	21.9%
Pepco	$70.50	$86.36	$15.86	22.5%
PPL	$63.52	$78.08	$14.56	22.9%
PSEG	$68.01	$85.82	$17.81	26.2%
RECO	$68.88	$84.73	$15.85	23.0%

Day-Ahead, Annual, Load-Weighted, Average LMP by Jurisdiction

Table 2-66 shows PJM's day-ahead, load-weighted, average LMPs for 2007 and 2008 by jurisdiction. The largest increase was in the New Jersey which experienced an $18.14, or 26.6 percent, increase over 2007, and the smallest increase was in Illinois which experienced a $6.56, or 13.9 percent, increase over 2007.

Table 2-66 Jurisdiction day-ahead, load weighted LMP (Dollars per MWh): Calendar years 2007 to 2008

	2007	2008	Difference	Difference as Percent of 2007
Delaware	$65.99	$82.99	$17.00	25.8%
Illinois	$47.27	$53.83	$6.56	13.9%
Indiana	$48.26	$56.53	$8.27	17.1%
Kentucky	$48.09	$56.02	$7.93	16.5%
Maryland	$70.07	$85.98	$15.91	22.7%
Michigan	$48.73	$57.83	$9.10	18.7%
New Jersey	$68.25	$86.39	$18.14	26.6%
North Carolina	$65.10	$78.13	$13.03	20.0%
Ohio	$47.43	$55.72	$8.29	17.5%
Pennsylvania	$60.10	$73.58	$13.48	22.4%
Tennessee	$49.30	$56.50	$7.20	14.6%
Virginia	$65.42	$78.63	$13.21	20.2%
West Virginia	$49.33	$57.56	$8.23	16.7%
District of Columbia	$70.08	$85.66	$15.58	22.2%

Marginal Losses

Marginal losses are the incremental change in system real power losses caused by changes in the system load and generation patterns.[44] Before June 1, 2007, the PJM economic dispatch and LMP models did not include marginal losses. The losses were treated as a static component of load, and the physical nature and location of power system losses were ignored. The PJM Tariff required implementation of marginal loss modeling when required technical systems became available. On June 1, 2007, PJM began including marginal losses in economic dispatch and LMP models.[45] The primary benefit of a marginal loss mechanism is that it more accurately models the physical reality of power system losses. More accurate models permit increased efficiency and optimize asset utilization. One characteristic of marginal loss modeling is that it creates a separate marginal loss price for every location on the power grid.

Table 2-67 shows the PJM real-time, simple average LMP components, including the loss component, for calendar years 2006 to 2008. As of June 1, 2007, PJM changed from a single node reference bus to a distributed load reference bus. While there is no effect on the total LMP, the components of LMP change with a shift in the reference bus. With a distributed load reference bus, the energy component is now a load-weighted system price. In turn, this means that there is no congestion or losses included at the PJM price, unlike the case with a single node reference bus. The energy price equals the PJM price in a given hour and on a yearly average basis. Table 2-67 shows a $0.04 loss component included at the PJM price. The PJM price is weighted with accounting load, which differs from the state-estimated load used in determination of the energy component. The $0.04 loss component of the average PJM system price results from these different weights. The $2.08 and $1.00 congestion component of the average PJM system price for 2006 and 2007 respectively, resulted from the fact that the distributed load reference bus did not go into effect until June 1, 2007.

Table 2-67 PJM real-time, simple average LMP components (Dollars per MWh): Calendar years 2006 to 2008

	Real-Time LMP	Energy Component	Congestion Component	Loss Component
2006	$49.27	$47.19	$2.08	$0.00
2007	$57.58	$56.56	$1.00	$0.02
2008	$66.40	$66.29	$0.06	$0.04

44 For additional information, see the *2008 State of the Market Report*, Volume II, Appendix J, "Marginal Losses."
45 For additional information, see PJM. "Open Access Transmission Tariff" (December 10, 2007), Section 3.4, Original Sheet No. 388G.

Table 2-68 shows the zonal real-time, simple average LMP components, including the loss component, for calendar years 2007 and 2008.

Table 2-68 Zonal real-time, simple average LMP components (Dollars per MWh): Calendar years 2007 and 2008

	2007				2008			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$65.02	$56.56	$6.42	$2.04	$80.70	$66.29	$10.77	$3.64
AEP	$46.55	$56.56	($8.80)	($1.21)	$53.42	$66.29	($10.46)	($2.42)
AP	$57.45	$56.56	$1.33	($0.44)	$65.85	$66.29	$0.29	($0.73)
BGE	$69.79	$56.56	$12.08	$1.15	$80.05	$66.29	$11.06	$2.69
ComEd	$45.71	$56.56	($9.42)	($1.43)	$49.38	$66.29	($13.46)	($3.46)
DAY	$46.47	$56.56	($9.54)	($0.55)	$53.68	$66.29	($11.18)	($1.43)
DLCO	$43.93	$56.56	($11.13)	($1.50)	$48.81	$66.29	($14.47)	($3.01)
Dominion	$66.75	$56.56	$9.89	$0.30	$75.87	$66.29	$8.76	$0.82
DPL	$64.15	$56.56	$6.09	$1.50	$77.20	$66.29	$7.69	$3.21
JCPL	$65.74	$56.56	$7.36	$1.82	$78.80	$66.29	$8.64	$3.87
Met-Ed	$64.57	$56.56	$7.32	$0.69	$74.70	$66.29	$6.51	$1.90
PECO	$62.60	$56.56	$4.82	$1.22	$75.07	$66.29	$6.11	$2.67
PENELEC	$54.80	$56.56	($1.46)	($0.30)	$63.37	$66.29	($2.33)	($0.59)
Pepco	$70.33	$56.56	$13.00	$0.77	$80.45	$66.29	$12.40	$1.76
PPL	$62.02	$56.56	$4.89	$0.57	$73.35	$66.29	$5.50	$1.55
PSEG	$65.92	$56.56	$7.43	$1.93	$79.14	$66.29	$8.92	$3.92
RECO	$64.85	$56.56	$6.50	$1.79	$77.46	$66.29	$7.62	$3.54

Table 2-69 shows the real-time, annual, simple average LMP loss component at the PJM hubs for 2008, for each hub in PJM.

Table 2-69 Hub real-time, simple average LMP components (Dollars per MWh): 2008

	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$50.35	$66.29	($11.29)	($4.66)
AEP-DAY Hub	$53.05	$66.29	($10.71)	($2.54)
Chicago Gen Hub	$48.60	$66.29	($13.32)	($4.37)
Chicago Hub	$49.43	$66.29	($13.42)	($3.44)
Dominion Hub	$73.89	$66.29	$7.37	$0.23
Eastern Hub	$77.15	$66.29	$7.17	$3.68
N Illinois Hub	$48.99	$66.29	($13.45)	($3.85)
New Jersey Hub	$79.02	$66.29	$8.92	$3.81
Ohio Hub	$53.09	$66.29	($10.84)	($2.36)
West Interface Hub	$58.40	$66.29	($5.35)	($2.55)
Western Hub	$68.53	$66.29	$2.80	($0.57)

Zonal and PJM Real-Time, Annual, Load-Weighted, Average LMP Components

Table 2-70 shows the real-time, annual, load-weighted, average LMP components for PJM and its 17 control zones for 2008.

Table 2-70 Zonal and PJM real-time, annual, load-weighted, average LMP components (Dollars per MWh): 2008

	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$90.55	$72.70	$13.83	$4.02
AEP	$56.65	$69.92	($10.74)	($2.53)
AP	$69.88	$70.30	$0.36	($0.79)
BGE	$87.11	$71.70	$12.43	$2.98
ComEd	$53.63	$70.52	($13.33)	($3.56)
DAY	$57.81	$70.68	($11.45)	($1.43)
DLCO	$52.45	$70.79	($15.10)	($3.23)
Dominion	$82.88	$72.04	$9.93	$0.91
DPL	$83.88	$72.07	$8.26	$3.55
JCPL	$86.43	$73.19	$9.03	$4.21
Met-Ed	$79.81	$70.97	$6.84	$2.00
PECO	$80.76	$71.44	$6.47	$2.84
PENELEC	$66.47	$69.60	($2.48)	($0.64)
Pepco	$87.89	$71.90	$14.06	$1.94
PPL	$77.79	$70.47	$5.67	$1.65
PSEG	$85.54	$71.95	$9.41	$4.19
RECO	$85.26	$73.69	$7.73	$3.85
PJM	$71.13	$71.02	$0.06	$0.05

Table 2-71 shows the PJM day-ahead, simple average LMP components, including the loss component, for calendar years 2006 to 2008. As of June 1, 2007, PJM changed from a single node reference bus to a distributed load reference bus. While there is no effect on the total LMP, the components of LMP change with a shift in the reference bus. With a distributed load reference bus, the energy component is now a load-weighted system price. In turn, this means that there is no congestion or losses included at the PJM price, unlike the case with a single node reference bus. The energy price equals the PJM price in a given hour and on a yearly average basis. In the Day-Ahead Energy Market, the distributed load reference bus is weighted with fixed-demand bids only and the day-ahead energy component is, therefore, a system fixed-demand-weighted price. The day-ahead system price calculation uses all types of demand, including fixed, price-sensitive and decrement bids. In the Real-Time Energy Market, the energy component equals the system load-weighted price; however, in the Day-Ahead Energy Market the energy component and the PJM system price are not equal, but the loss component and the congestion component have only a small effect. This is due to the use of all types of demand to weight the PJM price and not fixed demand only.

Table 2-71 PJM day-ahead, simple average LMP components (Dollars per MWh): 2006 to 2008

	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
2006	$48.10	$46.45	$1.65	$0.00
2007	$54.67	$54.60	$0.25	($0.18)
2008	$66.12	$66.43	($0.10)	($0.21)

Table 2-72 shows the zonal day-ahead, simple average LMP components, including the loss component, for calendar years 2007 and 2008.[46]

Table 2-72 Zonal day-ahead, simple average LMP components (Dollars per MWh): 2007 and 2008

	2007				2008			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$62.96	$54.60	$6.27	$2.09	$78.99	$66.43	$7.93	$4.63
AEP	$45.55	$54.60	($7.59)	($1.46)	$53.61	$66.43	($9.56)	($3.26)
AP	$54.88	$54.60	$0.77	($0.49)	$65.09	$66.43	($0.50)	($0.84)
BGE	$65.37	$54.60	$9.50	$1.27	$80.70	$66.43	$10.96	$3.31
ComEd	$45.35	$54.60	($7.80)	($1.45)	$50.50	$66.43	($11.37)	($4.56)
DAY	$45.29	$54.60	($8.12)	($1.19)	$53.53	$66.43	($10.04)	($2.86)
DLCO	$43.75	$54.60	($9.22)	($1.64)	$50.92	$66.43	($11.77)	($3.73)
Dominion	$63.42	$54.60	$8.42	$0.39	$75.60	$66.43	$8.07	$1.10
DPL	$61.95	$54.60	$5.72	$1.63	$77.95	$66.43	$7.63	$3.90
JCPL	$63.18	$54.60	$6.49	$2.09	$79.74	$66.43	$7.92	$5.39
Met-Ed	$61.62	$54.60	$6.24	$0.77	$75.54	$66.43	$6.59	$2.53
PECO	$61.25	$54.60	$5.01	$1.63	$76.23	$66.43	$5.93	$3.87
PENELEC	$52.97	$54.60	($1.14)	($0.50)	$65.11	$66.43	($0.91)	($0.41)
Pepco	$66.44	$54.60	$10.83	$1.00	$81.26	$66.43	$12.28	$2.55
PPL	$60.00	$54.60	$4.75	$0.65	$74.25	$66.43	$5.62	$2.20
PSEG	$63.94	$54.60	$7.05	$2.29	$79.77	$66.43	$7.76	$5.58
RECO	$63.37	$54.60	$6.77	$2.00	$78.08	$66.43	$6.55	$5.10

46 For some zones, energy component plus congestion component plus loss component may not equal the total day-ahead LMP because the total is based on the underlying data, which is not rounded.

Zonal and PJM Day-Ahead, Annual, Load-Weighted, Average LMP Components

Table 2-73 shows zonal and PJM day-ahead, annual, load-weighted, average LMP components for calendar year 2008.

Table 2-73 Zonal and PJM day-ahead, load-weighted, average LMP components (Dollars per MWh): 2008

	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$88.77	$73.92	$9.49	$5.37
AEP	$56.48	$69.68	($9.78)	($3.42)
AP	$67.94	$69.43	($0.58)	($0.91)
BGE	$87.50	$71.67	$12.14	$3.69
ComEd	$53.83	$69.83	($11.34)	($4.66)
DAY	$57.04	$70.32	($10.30)	($2.98)
DLCO	$54.33	$70.51	($12.18)	($4.00)
Dominion	$81.98	$71.77	$9.02	$1.20
DPL	$84.24	$71.97	$7.97	$4.29
JCPL	$86.65	$72.69	$8.16	$5.80
Met-Ed	$79.88	$70.51	$6.74	$2.63
PECO	$81.44	$71.24	$6.06	$4.14
PENELEC	$67.56	$68.65	($0.72)	($0.38)
Pepco	$86.36	$70.52	$13.10	$2.74
PPL	$78.08	$70.13	$5.66	$2.29
PSEG	$85.82	$71.93	$7.93	$5.97
RECO	$84.73	$72.81	$6.43	$5.49
PJM	$70.25	$70.56	($0.08)	($0.22)

Marginal Loss Accounting

With the implementation of marginal loss pricing, PJM calculates transmission loss charges for each PJM member. The loss charge is based on the applicable day-ahead and real-time loss component of LMP (loss LMP). Each PJM member is charged for the cost of losses on the transmission system, based on the difference between the loss LMP at the location where the PJM member injects energy and the loss LMP where the PJM member withdraws energy.

More specifically, total loss charges are equal to the load loss payments minus generation loss credits, plus explicit loss charges, incurred in both the Day-Ahead Energy Market and the balancing energy market.

- **Day-Ahead, Load Loss Payments.** Day-ahead, load loss payments are calculated for all cleared demand, decrement bids and Day-Ahead Energy Market sale transactions. (Decrement bids and energy sales can be thought of as scheduled load.) Day-ahead, load loss payments are calculated using MW and the load bus loss component of LMP (loss LMP), the decrement bid loss LMP or the loss LMP at the source of the sale transaction, as applicable.

- **Day-Ahead, Generation Loss Credits.** Day-ahead, generation loss credits are calculated for all cleared generation and increment offers and Day-Ahead Energy Market purchase transactions. (Increment offers and energy purchases can be thought of as scheduled generation.) Day-ahead, generation loss credits are calculated using MW and the generator bus loss LMP, the increment offer loss LMP or the loss LMP at the sink of the purchase transaction, as applicable.

- **Balancing, Load Loss Payments.** Balancing, load loss payments are calculated for all deviations between a PJM member's real-time load and energy sale transactions and their day-ahead cleared demand, decrement bids and energy sale transactions. Balancing, load loss payments are calculated using MW deviations and the real-time loss LMP for each bus where a deviation exists.

- **Balancing, Generation, Loss Credits.** Balancing, generation loss credits are calculated for all deviations between a PJM member's real-time generation and energy purchase transactions and the day-ahead cleared generation, increment offers and energy purchase transactions. Balancing, generation loss credits are calculated using MW deviations and the real-time loss LMP for each bus where a deviation exists.

- **Explicit Loss Charges.** Explicit loss charges are the net loss charges associated with point-to-point energy transactions. These charges equal the product of the transacted MW and loss LMP differences between sources (origins) and sinks (destinations) in the Day-Ahead Energy Market. Balancing energy market explicit loss charges equal the product of the differences between the real-time and day-ahead transacted MW and the differences between the real-time loss LMP at the transactions' sources and sinks.

Monthly Marginal Loss Costs

Table 2-74 shows a monthly summary of marginal loss costs by type for 2008. Marginal loss costs totaled $2.493 billion. The highest monthly loss cost was in July and totaled $365.7 million or 14.7 percent of the total. The majority of the marginal loss costs was in the Day-Ahead Energy Market and totaled $2.561 billion. The day-ahead costs were offset, in part, by a total of -$68 million in the balancing market. The overcollected portion of transmission losses that was credited back to load plus exports as of December 31, 2008, was $1.309 billion or 52.5 percent of the total losses. In determining the overcollected loss amount, PJM accumulates the day-ahead and balancing transmission loss charges paid by all customer accounts each hour, subtracts the spot market energy value of the actual transmission loss MWh during that hour, and allocates this amount as transmission loss credits each hour.[47]

Table 2-74 Marginal loss costs by type (Dollars (Millions)): 2008

	Marginal Loss Costs (Millions)								
	Day Ahead				Balancing				
	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total
Jan	$62.7	($154.5)	$10.1	$227.3	($1.7)	$1.5	($1.7)	($4.9)	$222.4
Feb	$52.7	($136.8)	$9.1	$198.7	($1.3)	($1.0)	($3.2)	($3.5)	$195.2
Mar	$55.1	($125.2)	$11.3	$191.7	($1.7)	$0.6	($4.3)	($6.6)	$185.1
Apr	$53.8	($116.8)	$12.8	$183.4	($2.9)	$2.0	($3.4)	($8.3)	$175.1
May	$53.0	($104.6)	$6.6	$164.2	($3.0)	$1.0	$0.4	($3.6)	$160.6
Jun	$93.1	($227.0)	$12.6	$332.7	($4.1)	($0.7)	($3.4)	($6.7)	$326.0
Jul	$103.3	($263.8)	$10.9	$378.1	($8.0)	$0.6	($3.7)	($12.4)	$365.7
Aug	$64.6	($162.3)	$11.9	$238.8	($2.3)	($1.3)	($5.4)	($6.4)	$232.4
Sep	$51.0	($121.2)	$13.2	$185.4	($0.9)	($0.4)	($6.3)	($6.8)	$178.6
Oct	$34.0	($99.9)	$11.7	$145.6	($1.8)	($2.4)	($4.8)	($4.2)	$141.4
Nov	$37.4	($105.3)	$11.5	$154.2	($0.7)	($2.8)	($5.6)	($3.4)	$150.8
Dec	$43.6	($107.4)	$10.4	$161.3	($0.7)	($3.6)	($4.2)	($1.2)	$160.1
Total	$704.3	($1,724.8)	$132.2	$2,561.3	($29.0)	($6.5)	($45.4)	($68.0)	$2,493.3

47 See PJM. "Manual 28: Operating Agreement Accounting," Revision 39 (January 1, 2008). Note that the overcollection is not calculated by subtracting the prior calculation of average losses from the calculated total marginal losses.

Zonal Marginal Loss Costs

Table 2-75 shows the marginal loss costs by type in each control zone in 2008. The AEP, ComEd and Dominion control zones had the highest marginal loss costs in 2008, with $505.7 million, $430.6 million and $239.2 million, respectively. Energy flows in PJM are generally from west to east, reflecting the fact that less expensive generation in the western portion of PJM is dispatched to assist in meeting the demand of load centers located in the eastern portion of PJM. Generation supplied from western resources to satisfy eastern load generally results in increased west-to-east transmission flow and increased losses. As may be seen in Table 2-75, the marginal loss generation credits in the western zones are generally greater in magnitude than those of the eastern zones. The characteristics of the marginal loss component of LMP are analogous to those of the congestion component of LMP, or CLMP. Generation congestion credits are generally negative for units located on the unconstrained side of a transmission element, indicating that an increase in output tends to increase the flow of energy across the constrained element. Analogously, the generation marginal loss credits are generally negative for units for which an increase in output tends to increase system losses.

Table 2-75 Marginal loss costs by control zone and type (Dollars (Millions)): 2008

Marginal Loss Costs by Control Zone (Millions)									
	Day Ahead				Balancing				
	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total
AECO	$60.3	$14.8	$0.7	$46.2	($0.2)	($0.5)	($0.2)	$0.1	$46.2
AEP	($89.1)	($595.6)	$21.7	$528.2	($22.9)	$1.1	$1.5	($22.5)	$505.7
AP	($15.0)	($196.6)	$6.9	$188.4	$6.2	$6.7	($1.5)	($1.9)	$186.4
BGE	$96.2	$14.6	$1.8	$83.5	$1.9	($3.6)	($1.5)	$4.0	$87.4
ComEd	($190.0)	($609.0)	$1.4	$420.4	$4.7	($5.8)	($0.3)	$10.2	$430.6
DAY	($9.0)	($90.0)	$2.4	$83.3	($1.2)	$2.9	$0.1	($4.0)	$79.3
DLCO	($52.5)	($104.8)	$0.0	$52.3	($12.2)	$3.8	$0.0	($16.0)	$36.3
Dominion	$103.7	($130.6)	$6.5	$240.8	$3.0	$0.8	($3.7)	($1.6)	$239.2
DPL	$84.7	$19.7	$0.6	$65.6	$1.0	($0.4)	($0.2)	$1.3	$66.9
JCPL	$146.3	$51.6	$4.3	$99.0	$0.9	($1.6)	($3.2)	($0.8)	$98.2
Met-Ed	$40.2	$12.6	$1.9	$29.5	$0.4	($0.6)	$3.8	$4.9	$34.4
PECO	$136.7	$28.8	$0.2	$108.1	($0.1)	$0.5	($0.1)	($0.6)	$107.4
PENELEC	($45.2)	($184.7)	$1.4	$140.9	$0.8	$0.4	$0.9	$1.3	$142.2
PEPCO	$129.2	$50.6	$3.8	$82.4	($0.2)	($1.0)	($2.8)	($2.0)	$80.4
PJM	$8.2	($27.6)	$57.7	$93.4	($12.1)	($16.8)	($26.0)	($21.3)	$72.1
PPL	$88.2	($23.6)	$5.4	$117.2	$0.7	($0.1)	($0.3)	$0.5	$117.7
PSEG	$203.0	$44.8	$14.5	$172.8	$0.2	$7.8	($11.3)	($18.8)	$154.0
RECO	$8.5	$0.2	$1.1	$9.4	$0.1	($0.1)	($0.7)	($0.5)	$8.9
Total	$704.3	($1,724.8)	$132.2	$2,561.3	($29.0)	($6.5)	($45.4)	($68.0)	$2,493.3

Table 2-76 shows the monthly marginal loss cost, by control zone in 2008.

Table 2-76 Monthly marginal loss costs by control zone (Dollars (Millions)): 2008

	Marginal Loss Costs by Control Zone (Millions)												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Grand Total
AECO	$2.9	$2.6	$2.7	$2.6	$3.7	$7.2	$9.7	$5.3	$2.9	$2.2	$2.3	$2.2	$46.2
AEP	$50.7	$42.6	$37.2	$32.7	$30.5	$68.0	$81.1	$49.4	$36.3	$27.3	$24.5	$25.3	$505.7
AP	$18.4	$15.0	$16.9	$12.1	$10.5	$21.8	$26.8	$16.7	$11.0	$11.4	$13.4	$12.5	$186.4
BGE	$6.6	$6.0	$5.1	$5.0	$5.3	$13.4	$15.1	$9.2	$6.5	$4.2	$5.4	$5.4	$87.4
ComEd	$33.4	$29.6	$33.5	$34.9	$28.6	$52.4	$52.5	$39.4	$33.1	$30.2	$33.0	$30.0	$430.6
DAY	$7.8	$8.0	$5.9	$5.7	$6.8	$10.2	$9.6	$5.9	$5.7	$3.4	$5.0	$5.3	$79.3
DLCO	$3.6	$3.0	$3.7	$1.9	$0.4	$4.5	$4.7	$3.1	$2.8	$2.6	$3.0	$3.1	$36.3
Dominion	$20.3	$16.8	$15.3	$14.2	$14.8	$36.7	$39.2	$24.9	$17.9	$12.6	$12.3	$14.2	$239.2
DPL	$5.4	$4.5	$4.1	$3.9	$3.8	$10.1	$11.5	$7.9	$5.0	$3.2	$3.5	$4.0	$66.9
JCPL	$9.3	$7.9	$8.8	$8.2	$6.9	$12.1	$14.1	$7.7	$6.0	$4.3	$5.8	$7.0	$98.2
Met-Ed	$3.3	$3.4	$3.0	$3.1	$3.2	$4.3	$4.2	$2.7	$2.0	$1.7	$1.6	$1.9	$34.4
PECO	$9.9	$9.2	$8.7	$6.8	$6.7	$15.8	$17.1	$10.1	$6.4	$4.4	$6.1	$6.3	$107.4
PENELEC	$14.9	$12.3	$10.4	$9.3	$9.5	$18.0	$21.9	$14.1	$9.7	$7.3	$6.7	$8.1	$142.2
PEPCO	$6.5	$5.8	$5.1	$5.2	$5.5	$11.2	$12.2	$7.8	$6.4	$5.0	$4.8	$4.7	$80.4
PJM	$3.6	$6.1	$2.9	$7.0	$4.5	$3.3	$5.4	$6.3	$8.1	$6.0	$7.2	$11.7	$72.1
PPL	$12.4	$10.5	$9.2	$7.8	$7.5	$15.4	$16.2	$9.1	$7.7	$6.8	$7.1	$7.9	$117.7
PSEG	$12.7	$11.2	$11.8	$14.1	$11.7	$20.3	$22.9	$12.1	$10.2	$8.5	$8.6	$9.9	$154.0
RECO	$0.6	$0.6	$0.6	$0.7	$0.7	$1.2	$1.5	$0.7	$0.9	$0.4	$0.5	$0.5	$8.9
Total	$222.4	$195.2	$185.1	$175.1	$160.6	$326.0	$365.7	$232.4	$178.6	$141.4	$150.8	$160.1	$2,493.3

Virtual Offers and Bids

The PJM Day-Ahead Energy Market includes the ability to make increment offers (INC) and decrement bids (DEC) at any hub, transmission zone, aggregate, or single bus for which LMP is calculated. Since increment offers and decrement bids do not require physical generation or load, they are also referred to as virtual offers and bids. Virtual offers and bids also provide participants the flexibility, for example, to cover one side of a bilateral transaction, hedge day-ahead generator offers or demand bids, and arbitrage day-ahead and real-time prices.

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

Table 2-77 shows the frequency with which generation offers, import or export transactions, decrement bids, increment offers and price-sensitive demand are marginal for each month in 2008.[48] Together, increment offers and decrement bids represented 53.1 percent of the marginal bids or offers in 2008.

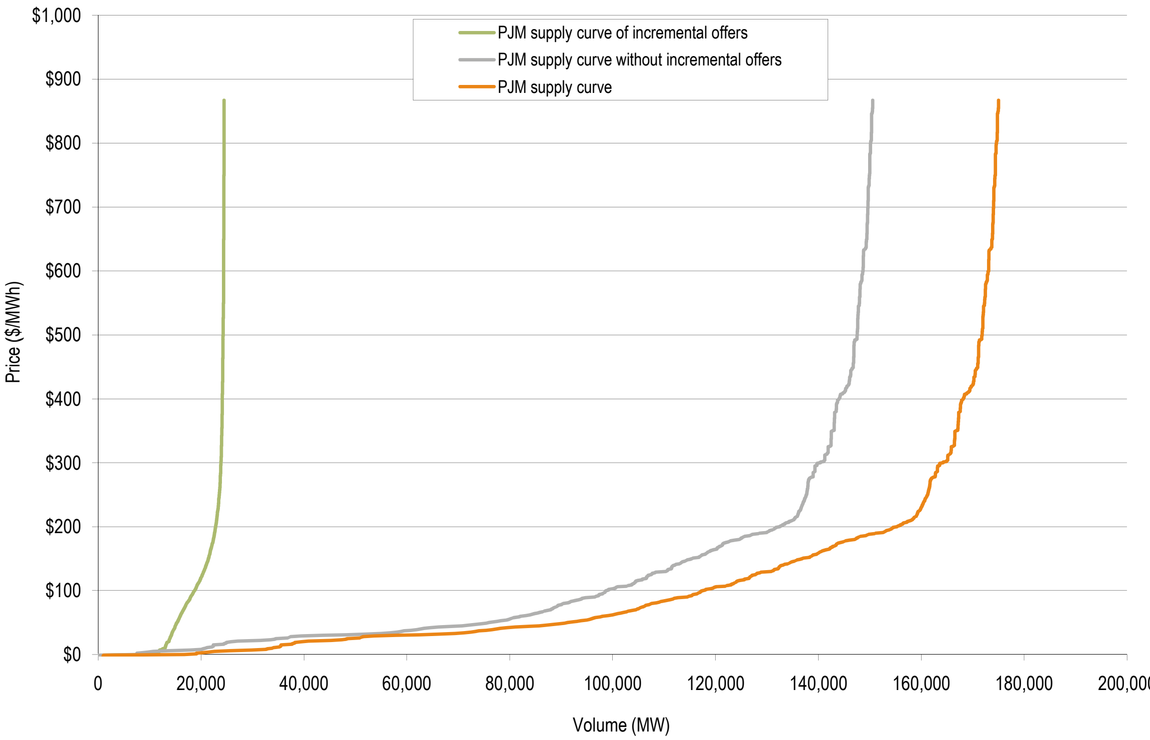
Table 2-77 Type of day-ahead marginal units: Calendar year 2008

	Generation	Transaction	Decrement Bid	Increment Offer	Price-Sensitive Demand
Jan	11.9%	25.3%	44.3%	18.0%	0.4%
Feb	15.0%	25.5%	44.6%	14.3%	0.6%
Mar	15.7%	28.8%	36.2%	18.7%	0.6%
Apr	18.3%	29.1%	32.2%	19.3%	1.0%
May	20.8%	24.3%	32.0%	21.2%	1.6%
Jun	17.5%	23.2%	33.8%	23.8%	1.6%
Jul	14.6%	21.2%	41.2%	21.3%	1.7%
Aug	12.7%	29.4%	38.7%	18.2%	1.0%
Sep	17.8%	31.2%	33.3%	16.7%	1.0%
Oct	18.2%	41.3%	25.7%	13.7%	1.1%
Nov	20.8%	36.3%	26.6%	14.9%	1.4%
Dec	24.8%	34.7%	27.1%	12.3%	1.0%
Annual	16.9%	28.8%	35.1%	18.0%	1.1%

48 These percentages compare the number of times that bids and offers of the specified type were marginal to the total number of marginal bids and offers. There is no weighting by time or by load.

Figure 2-16 shows the PJM day-ahead daily aggregate supply curve of increment offers, the system aggregate supply curve without increment offers and the system aggregate supply curve with increment offers for an example day in June 2008. There were average hourly increment offers of 24,488 MW and average hourly total offers of 175,013 MW for the example day.

Figure 2-16 PJM day-ahead aggregate supply curves: 2008 example day



Price Convergence

When the PJM Day-Ahead Energy Market was introduced, it was expected that competition, exercised substantially through the use of virtual offers and bids, would tend to cause prices in the Day-Ahead and Real-Time Energy Markets to converge. But 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 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 is not a realistic expectation. PJM markets do not provide a mechanism that could result in convergence within any individual day as there is at least a one-day lag after any change in system conditions. As a general matter, virtual offers and bids are based on expectations about both Day-Ahead and Real-Time Market conditions and reflect the uncertainty about conditions in both markets and the fact that these conditions change hourly and daily. 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. (See Figure 2-17.) There may be substantial, persistent differences between day-ahead and real-time prices even on a monthly basis. (See Figure 2-18.)

As Table 2-78 shows, day-ahead and real-time prices were relatively close, on average, during 2008. Average LMP in the Real-Time Energy Market was $0.28 per MWh or 0.4 percent higher than average LMP in the Day-Ahead Energy Market during 2008.

Table 2-78 Day-Ahead and Real-Time Energy Market LMP (Dollars per MWh): Calendar year 2008

	Day Ahead	Real Time	Difference	Difference as Percent Real Time
Average	$66.12	$66.40	$0.28	0.4%
Median	$58.93	$55.53	($3.40)	(6.1%)
Standard deviation	$30.87	$38.62	$7.75	20.1%

The price difference between the Real-Time and the Day-Ahead Energy Markets results, in part, from volatility in the Real-Time Energy Market that is difficult, or impossible, to anticipate in the Day-Ahead Energy Market. In 2008, real-time prices were higher than day-ahead prices by more than $50 per MWh for 328 hours, more than $100 per MWh for 44 hours and more than $150 per MWh for 7 hours. If the hours with price differences greater than $150 per MWh are excluded, the difference between real-time and day-ahead price is $0.13 per MWh in 2008 rather than $0.28. Although real-time prices were higher than day-ahead prices on average in 2008, real-time prices were lower than day-ahead prices for 59.3 percent of the hours. During hours when real-time prices were higher than day-ahead prices, the average positive difference between them was $19.28 per MWh. During hours when real-time prices were less than day-ahead prices, the average negative difference was -$12.76 per MWh.

Table 2-79 shows the difference between the Real-Time and the Day-Ahead Energy Market Prices from 2000 to 2008. On average, day-ahead prices were lower than real-time prices by $2.90 per MWh during 2007, $1.17 per MWh during 2006, by $0.18 per MWh in 2005 and by $0.97 per MWh in 2004. On average, day-ahead prices were higher than real-time prices by $0.45 per MWh in 2003, by $0.16 per MWh in 2002, by $0.37 per MWh in 2001 and by $1.61 per MWh in 2000.[49]

Table 2-79 Day-Ahead and Real-Time Energy Market LMP (Dollars per MWh): Calendar years 2000 to 2008

Year	Day Ahead	Real Time	Difference	Difference as Percent Real Time
2000	$31.97	$30.36	($1.61)	(5.3%)
2001	$32.75	$32.38	($0.37)	(1.1%)
2002	$28.46	$28.30	($0.16)	(0.6%)
2003	$38.73	$38.28	($0.45)	(1.2%)
2004	$41.43	$42.40	$0.97	2.3%
2005	$57.89	$58.08	$0.18	0.3%
2006	$48.10	$49.27	$1.17	2.4%
2007	$54.67	$57.58	$2.90	5.0%
2008	$66.12	$66.40	$0.28	0.4%

49 Since the Day-Ahead Energy Market starts from June 1,2000, the data in 2000 starts from June 1, 2000. However, the starting date for years 2001 to 2008 is January 1.

Table 2-80 provides frequency distributions of the differences between PJM real-time hourly LMP and PJM day-ahead hourly LMP for calendar years 2004 through 2008. The table shows the number of hours (frequency) and the cumulative percent of hours (cumulative percent) when the hourly LMP difference was within a given $50 per MWh price interval. From calendar year 2004 to calendar year 2008, LMP differences occurred predominantly in the range between ($50) per MWh and $50 per MWh. The largest PJM real-time and day-ahead hourly LMP difference occurred in the calendar year of 2006 where an hourly price difference was greater than $500 per MWh. In 2007, the PJM real-time and day-ahead hourly LMP differences are less than $150 per MWh in all but 14 hours. In 2008, the PJM real-time and day-ahead hourly LMP differences are less than $150 per MWh in all but 7 hours.

Table 2-80 Frequency distribution by hours of PJM real-time and day-ahead LMP difference (Dollars per MWh): Calendar years 2004 to 2008

	2004		2005		2006		2007		2008	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
< ($150)	0	0.00%	0	0.00%	1	0.01%	0	0.00%	0	0.00%
($150) to ($100)	0	0.00%	1	0.01%	1	0.02%	0	0.00%	1	0.01%
($100) to ($50)	5	0.06%	64	0.74%	9	0.13%	33	0.38%	88	1.01%
($50) to $0	4,583	52.23%	5,015	57.99%	5,205	59.54%	4,600	52.89%	5,120	59.30%
$0 to $50	4,146	99.43%	3,471	97.61%	3,372	98.04%	3,827	96.58%	3,247	96.27%
$50 to $100	49	99.99%	190	99.78%	152	99.77%	255	99.49%	284	99.50%
$100 to $150	1	100.00%	17	99.98%	9	99.87%	31	99.84%	37	99.92%
$150 to $200	0	0.00%	2	100.00%	4	99.92%	5	99.90%	4	99.97%
$200 to $250	0	100.00%	0	100.00%	1	99.93%	1	99.91%	2	99.99%
$250 to $300	0	100.00%	0	100.00%	3	99.97%	3	99.94%	0	99.99%
$300 to $350	0	100.00%	0	100.00%	0	99.97%	2	99.97%	1	100.00%
$350 to $400	0	100.00%	0	100.00%	1	99.98%	1	99.98%	0	100.00%
$400 to $450	0	100.00%	0	100.00%	0	99.98%	1	99.99%	0	100.00%
$450 to $500	0	100.00%	0	100.00%	1	99.99%	1	100.00%	0	100.00%
>= $500	0	100.00%	0	100.00%	1	100.00%	0	100.00%	0	100.00%

Figure 2-17 shows the hourly differences between day-ahead and real-time LMP in 2008. Although the average difference between the Day-Ahead and Real-Time Energy Market was $0.28 per MWh for the entire year, Figure 2-17 demonstrates the considerable variation, both positive and negative, between day-ahead and real-time prices. The highest difference between real-time and day-ahead LMP was $311.30 per MWh for the hour ended 1600 on June 12, 2008, when the real-time LMP was $483.27 (peak real-time LMP for 2008) and the day-ahead LMP was $171.97.

Figure 2-17 Hourly real-time minus hourly day-ahead LMP: Calendar year 2008

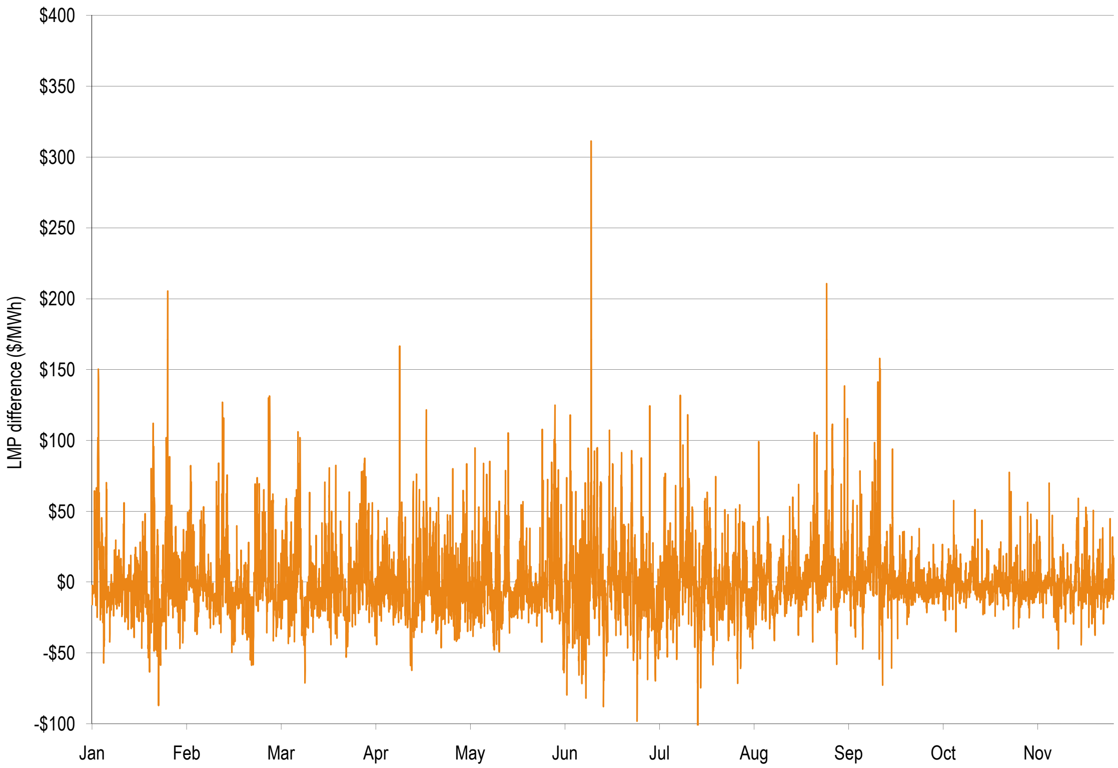


Figure 2-18 shows the monthly average differences between the day-ahead and real-time LMP in 2008. The highest monthly difference was in September.

Figure 2-18 Monthly average of real-time minus day-ahead LMP: Calendar year 2008

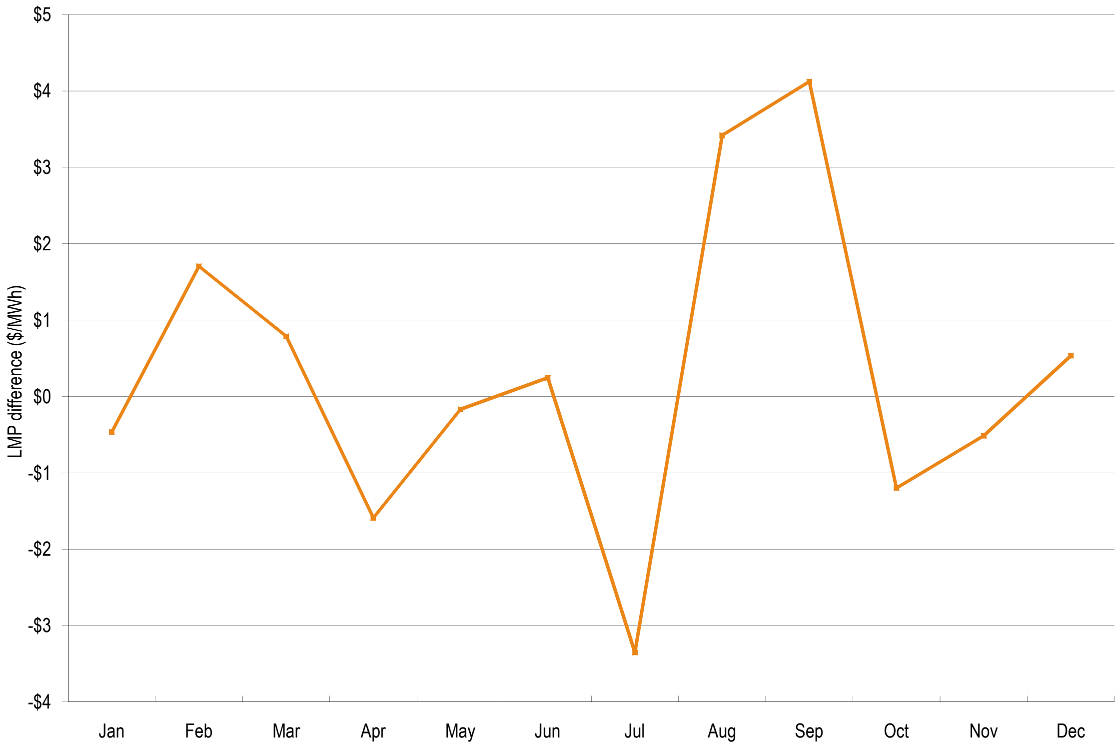
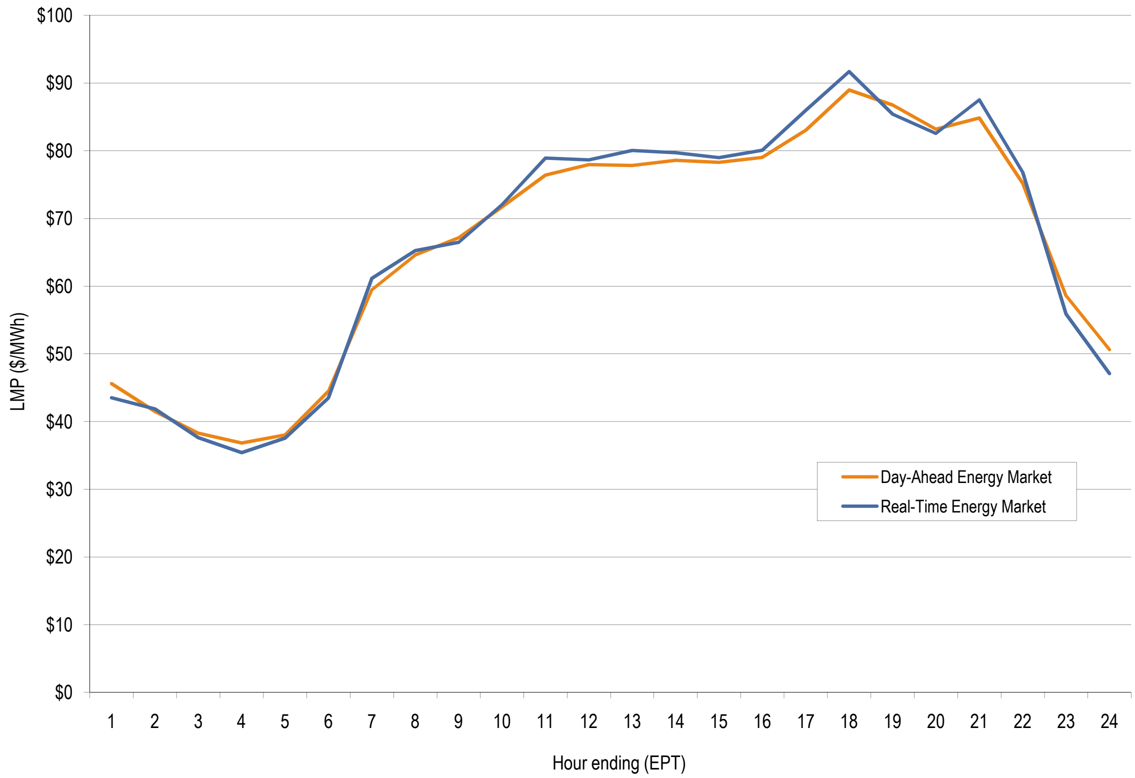


Figure 2-19 shows day-ahead and real-time LMP on an average hourly basis. Real-time average LMP was greater than day-ahead average LMP for 22 out of 24 hours.[50]

Figure 2-19 PJM system hourly average LMP: Calendar year 2008



50 See the *2008 State of the Market Report*, Volume II, Appendix C, "Energy Market," for more details on the frequency distribution of prices.

Zonal Price Convergence

Table 2-81 shows 2008 zonal day-ahead and real-time average LMP. The difference between zonal day-ahead and real-time LMP ranged from $2.11 in the DLCO Control Zone, where the day-ahead average LMP was higher than the real-time average LMP, to $1.71 in the AECO Control Zone, where the day-ahead average LMP was lower than the real-time average LMP.

Table 2-81 Zonal Day-Ahead and Real-Time Energy Market LMP (Dollars per MWh): Calendar year 2008

	Day Ahead	Real Time	Difference	Difference as Percent Real Time
AECO	$78.99	$80.70	$1.71	2.1%
AEP	$53.61	$53.42	($0.19)	(0.4%)
AP	$65.09	$65.85	$0.76	1.2%
BGE	$80.70	$80.05	($0.65)	(0.8%)
ComEd	$50.50	$49.38	($1.12)	(2.3%)
DAY	$53.53	$53.68	$0.15	0.3%
DLCO	$50.92	$48.81	($2.11)	(4.3%)
Dominion	$75.60	$75.87	$0.27	0.4%
DPL	$77.95	$77.20	($0.75)	(1.0%)
JCPL	$79.74	$78.80	($0.94)	(1.2%)
Met-Ed	$75.54	$74.70	($0.84)	(1.1%)
PECO	$76.23	$75.07	($1.16)	(1.5%)
PENELEC	$65.11	$63.37	($1.74)	(2.7%)
Pepco	$81.26	$80.45	($0.81)	(1.0%)
PPL	$74.25	$73.35	($0.90)	(1.2%)
PSEG	$79.77	$79.14	($0.63)	(0.8%)
RECO	$78.08	$77.46	($0.62)	(0.8%)

Price Convergence by Jurisdiction

Table 2-82 shows the 2008 day-ahead and real-time average LMPs by jurisdiction. The difference between day-ahead and real-time LMP ranged from $1.12 in Illinois, where the day-ahead average LMP was higher than the real-time average LMP, to $0.44 in Maryland, where the day-ahead average LMP was lower than the real-time average LMP.

Table 2-82 Jurisdiction Day-Ahead and Real-Time Energy Market LMP (Dollars per MWh): Calendar year 2008

	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
Delaware	$76.88	$76.26	($0.62)	(0.8%)
Illinois	$50.50	$49.38	($1.12)	(2.3%)
Indiana	$53.58	$53.01	($0.57)	(1.1%)
Kentucky	$53.36	$53.80	$0.44	0.8%
Maryland	$80.01	$79.75	($0.26)	(0.3%)
Michigan	$54.48	$54.07	($0.41)	(0.8%)
New Jersey	$79.68	$79.27	($0.41)	(0.5%)
North Carolina	$71.66	$71.69	$0.03	0.0%
Ohio	$52.85	$52.64	($0.21)	(0.4%)
Pennsylvania	$70.04	$68.98	($1.06)	(1.5%)
Tennessee	$54.24	$54.36	$0.12	0.2%
Virginia	$73.01	$73.20	$0.19	0.3%
West Virginia	$54.67	$55.02	$0.35	0.6%
District of Columbia	$81.04	$80.57	($0.47)	(0.6%)

Load and Spot Market

Real-Time Load and Spot Market[51]

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

51 The analysis here differs from that presented in the *2007 State of the Market Report* in several respects. The billing organization analysis is not included here because it is not a meaningful representation of the ways in which load is served in PJM. Rather, billing organization data reflects decisions by parent organizations about where to incorporate the load serving obligation. In addition, the transfer of load serving obligations via eSchedule bilateral contracts is treated as a transfer of load serving obligation rather than as a bilateral to serve load.

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 at the same time that it is meeting load. Supply from spot market purchases means that the parent company is not generating enough power from owned plants and/or not purchasing enough power under bilateral contracts 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 PJM parent companies that serve load in the Real-Time Energy Market for each hour. Table 2-83 shows the monthly average share of real-time load served by self-supply, bilateral contract and spot purchase in 2007 and 2008 based on parent company. For 2008, 14.6 percent real-time load was supplied by bilateral contracts, 20.1 percent by spot market purchase and 65.2 percent by self-supply. Compared with 2007, reliance on bilateral contracts decreased 2.0 percentage points, reliance on spot supply increased by 4.2 percentage points and reliance on self-supply decreased by 2.3 percentage points.

Table 2-83 Monthly average percentage of real-time self-supply load, bilateral-supply load and spot-supply load based on parent companies: Calendar years 2007 to 2008

	2007			2008			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	16.5%	14.4%	69.1%	14.3%	17.3%	68.4%	(2.2%)	2.9%	(0.7%)
Feb	16.5%	14.2%	69.3%	15.2%	17.3%	67.5%	(1.3%)	3.1%	(1.8%)
Mar	17.2%	14.6%	68.2%	16.0%	17.1%	66.9%	(1.2%)	2.5%	(1.3%)
Apr	17.4%	14.9%	67.7%	16.6%	18.0%	65.4%	(0.8%)	3.1%	(2.3%)
May	18.2%	14.1%	67.7%	16.0%	18.8%	65.3%	(2.2%)	4.7%	(2.4%)
Jun	16.9%	15.3%	67.8%	13.1%	21.0%	65.9%	(3.8%)	5.7%	(1.9%)
Jul	15.8%	17.2%	66.9%	13.7%	20.6%	65.7%	(2.1%)	3.4%	(1.2%)
Aug	15.5%	16.7%	67.8%	14.9%	22.6%	62.4%	(0.6%)	5.9%	(5.4%)
Sep	15.6%	17.1%	67.3%	14.7%	23.0%	62.2%	(0.9%)	5.9%	(5.1%)
Oct	17.3%	18.2%	64.5%	15.1%	22.7%	62.2%	(2.2%)	4.5%	(2.3%)
Nov	17.1%	17.0%	65.9%	14.8%	22.9%	62.3%	(2.3%)	5.9%	(3.6%)
Dec	15.7%	16.8%	67.5%	12.1%	20.5%	67.4%	(3.6%)	3.7%	(0.1%)
Annual	16.6%	15.9%	67.5%	14.6%	20.1%	65.2%	(2.0%)	4.2%	(2.3%)

Day-Ahead Load and Spot Market[52]

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 generation 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 load (cleared fixed-demand, price-sensitive load and decrement bids) is calculated by summing across all the parent companies of PJM billing organizations that serve load in the Day-Ahead Energy Market for each hour. Table 2-84 shows the monthly average share of day-ahead load served by self-supply, bilateral contracts and spot purchases in 2007 and 2008, based on parent companies. For 2008, 5.0 percent of day-ahead load was supplied by bilateral contracts, 18.4 percent by spot market purchases, and 76.5 percent by self-supply. Compared with 2007, reliance on bilateral contracts increased by 0.5 percentage points, reliance on spot supply increased by 3.9 percentage points, and reliance on self-supply decreased by 4.5 percentage points.

Table 2-84 Monthly average percentage of day-ahead self-supply load, bilateral supply load, and spot-supply load based on parent companies: Calendar Years 2007 to 2008

	2007			2008			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	3.9%	12.9%	83.2%	4.2%	15.6%	80.2%	0.3%	2.7%	(3.0%)
Feb	4.1%	13.1%	82.8%	4.5%	16.0%	79.5%	0.4%	2.9%	(3.3%)
Mar	4.2%	13.3%	82.5%	4.7%	16.0%	79.3%	0.5%	2.7%	(3.2%)
Apr	4.5%	12.8%	82.7%	5.0%	16.8%	78.2%	0.5%	4.0%	(4.5%)
May	5.1%	12.5%	82.4%	5.0%	18.2%	76.8%	(0.1%)	5.7%	(5.6%)
Jun	4.5%	14.9%	80.6%	5.5%	20.2%	74.3%	1.0%	5.3%	(6.3%)
Jul	4.2%	15.9%	79.9%	5.6%	20.4%	74.0%	1.4%	4.5%	(5.9%)
Aug	4.1%	15.4%	80.5%	4.9%	20.2%	75.0%	0.8%	4.8%	(5.5%)
Sep	4.8%	15.5%	79.7%	5.4%	19.3%	75.3%	0.6%	3.8%	(4.4%)
Oct	4.9%	16.5%	78.6%	5.4%	20.3%	74.3%	0.5%	3.8%	(4.3%)
Nov	5.2%	15.6%	79.3%	5.6%	18.9%	75.5%	0.4%	3.3%	(3.8%)
Dec	5.2%	15.4%	79.3%	4.6%	19.1%	76.3%	(0.6%)	3.7%	(3.0%)
Annual	4.5%	14.5%	81.0%	5.0%	18.4%	76.5%	0.5%	3.9%	(4.5%)

52 The analysis here differs from that presented in the *2007 State of the Market Report* in several respects. In addition to the changes made in the analysis of the Real-Time Energy Market, the analysis of the Day-Ahead Market treats increment offers as generation and decrement bids as load rather than showing virtuals separately.

Virtual Markets

Increment Offers and Decrement Bids

Any market participant in the PJM Day-Ahead Energy Market can use increment offers and decrement bids 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. Table 2-85 shows the average volume of trading in virtual bids per hour, as well as the average total MW values of all virtual bids per hour.

Table 2-85 Monthly volume of cleared and submitted INCs, DECs: calendar year 2008

	Increment Offers				Decrement Bids			
	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
Jan	15,842	22,235	252	490	21,051	29,956	293	592
Feb	15,704	21,725	244	449	20,352	27,978	294	497
Mar	15,131	21,496	242	468	18,477	25,560	298	483
Apr	15,355	22,298	292	566	18,093	25,106	316	543
May	14,344	21,434	431	689	16,777	22,174	407	552
Jun	14,237	22,803	506	811	18,540	25,504	627	849
Jul	16,605	25,666	597	919	21,016	29,980	721	951
Aug	17,315	26,861	628	965	20,553	28,939	618	811
Sep	14,846	22,603	502	761	18,816	25,403	837	1,017
Oct	13,049	20,951	519	758	16,548	22,648	555	734
Nov	13,595	21,451	523	727	16,546	22,907	473	637
Dec	12,817	20,193	464	660	15,950	21,999	535	678
Annual	14,904	22,486	435	690	18,562	25,688	499	697

Demand-Side Response (DSR)

Markets require both a supply side and a demand side to function effectively. The demand side of wholesale electricity markets is underdeveloped. It is widely recognized that wholesale electricity markets will work better when a significant level of potential demand-side response is available in the market. PJM wholesale market, demand-side programs should be understood as one relatively small part of a transition to a fully functional demand side for its Energy Market. A fully developed demand side will include retail programs and an active, well-articulated interaction between wholesale and retail markets.

A functional demand side of the electricity market does not mean that all customers curtail usage at specified levels of price. A fully functional demand side of the electricity market does mean that the default energy price for all customers will be the day-ahead or real-time hourly LMP. Customers will be able to choose to pay the day-ahead or real-time prices or to hedge their exposure to those prices by using an intermediary. A fully functional demand side of the electricity market does mean that all or most customers, or their designated intermediaries, will have the ability to see real-time prices in real time, will have the ability to react to real-time prices in real time and will have the ability to receive the direct benefits or costs of changes in real-time energy use, based on real-time energy prices. In addition, customers will be able to specify the maximum price at which they wish to purchase power in the Day-Ahead Market. If these conditions are met, customers can decide for themselves the relationship between the price of power and the value of particular activities, from operating a production plant to running a commercial building to running a residential air conditioner. The true goal of demand-side programs is to ensure that customers can make informed decisions about energy consumption. Customers can and will make investments in demand-side management technologies based on their own evaluations of the tradeoffs among the price of power, the value of particular activities and the costs of those technologies.

A functional demand side of the wholesale energy market does not necessarily mean that prices will be lower than they otherwise would be. A functional demand side of these markets does mean, however, that customers will have the ability to make decisions about levels of power consumption based both on the value of the uses of the power and on the actual cost of that power.

A functional demand side of the wholesale electricity market would also send explicit price signals to suppliers, inducing more competitive behavior among suppliers and providing a market-based limit to suppliers' ability to exercise market power. If customers had the essential tools to respond to prices, then suppliers would have the incentive to deliver power on a cost-effective basis, consistent with their customers' evaluations.

The purpose of PJM's demand-side Economic Program is, or should be, to address a specific market failure, which is that many retail customers do not pay the market price or LMP. This represents a market failure because when customers do not pay the market price, the behavior of those customers is inconsistent with the market value of electricity. When customers pay a price less than the market price, customers will tend to consume more than if they faced the market price and when customers pay a price greater than the market price, customers will tend to consume less than they would if they faced the market price. This market failure is relevant to the wholesale power market because the power used by customers is generated and sold in the wholesale power market.

Based on this purpose, the design goal of the Economic Program incentives should be to replicate the price signal to customers that would exist if customers were exposed to the real-time wholesale price. The real-time hourly LMP is the appropriate price signal as it reflects the incremental value of each MWh consumed.[53] The goal of the program should not be to encourage increased or decreased consumption, but to permit customers to face the market price and to make consumption decisions consistent with that price.

The PJM Economic Program is a wholesale program and its goal should be to ensure that the appropriate wholesale price signal is provided to customers but should not be to address retail rate issues. The design of retail incentives is a matter for state public utility commissions.

Retail customers pay retail rates including components that reflect the cost of generation (or power purchased from the grid), the cost of transmission and the cost of distribution. Under a rate design consistent with the purpose of the demand-side program, the hourly LMP would replace only the generation component of retail rates in order to provide the appropriate wholesale market price signal to customers. The LMP reflects the economic value of wholesale power and does not reflect the value of transmission or distribution services.

On March 15, 2002, PJM submitted filing amendments to the OATT and to the OA to establish a multiyear Economic Load-Response Program (the Economic Program).[54] On May 31, 2002, the FERC accepted the Economic Program, effective June 1, 2002, but with a December 1, 2004, sunset provision.[55] On October 29, 2004, the FERC extended the Economic Program until December 31, 2007.[56] On February 24, 2006, the FERC approved changes to the PJM Tariff to permit demand-side resources to provide ancillary services and to make the Economic Program permanent.[57,58] The same order permitted, for individual participants using the nonhourly metered option, an increase in the limit on the combined total MW in the Economic and Emergency Programs from 100 MW to 500 MW.

On November 20, 2007, the PJM Industrial Customer Coalition (PJMICC) filed a complaint with the FERC requesting continuation of Economic Load-Response subsidy payments that, under the existing PJM Tariff, would expire on December 31, 2007.[59] The Commission denied the complaint, stating that “Even without the subsidy payments, the Economic Program provides customers within PJM the incentive to reduce load based on the wholesale rates they confront.”[60,61] On December 31, 2007, the Economic Program incentive payment provisions expired per the PJM OA.

The PJM Economic Load-Response Program is a PJM-managed accounting mechanism that provides for payment of the savings that result from load reductions to the load-reducing customer. Such a mechanism is required because of the complex interaction between the wholesale market and the retail incentive and regulatory structures faced by both load-serving entities (LSEs) and

53 This does not mean that every retail customer should be required to pay the real-time LMP, regardless of their risk preferences. However, it would provide the appropriate price signal if every retail customer were obligated to pay the real-time LMP as a default. That risk could be hedged via a contract with an intermediary.

54 *PJM Interconnection, L.L.C.*, Tariff Amendments, Docket No. ER02-1326-000 (March 15, 2002).

55 99 FERC ¶ 61,227 (2002).

56 *PJM Interconnection, L.L.C.,* Letter Order, Docket No. ER04-1193-000 (October 29, 2004).

57 114 FERC ¶ 61,201 (February 24, 2006).

58 Analysis of the role of demand-side resources in the Ancillary Service Markets can be found in the *2008 State of the Market Report,* Volume II, Section 6, “Ancillary Service Markets,” at “Synchronized Reserve Market.”

59 See PJM. “Amended and Restated Operating Agreement (OA),” Schedule 1, Section 3.3.A (December 10, 2007).

60 121 FERC ¶ 61,315 (December 31, 2007) at ¶ 26.

61 For a discussion of subsidy payments under PJM’s Economic Load-Response Program, see “MMU White Paper: PJM Demand Side Response Program” (December 4, 2007) <http://www.monitoringanalytics.com/reports/Reports/2007/20071204-dsr-whitepaper.pdf> (115 KB).

customers. The broader goal of the Economic Program is a transition to a structure where customers do not require mandated payments, but where customers see and react to market prices or enter into contracts with intermediaries to provide that service. Even as currently structured, however, and even with the reintroduction of the defined subsidies, if they exclude previously identified inappropriate components, the Economic Program represents a minimal and relatively efficient intervention into the market.[62]

On February 14, 2002, the PJM Members Committee approved a permanent Emergency Load-Response Program.[63] On March 1, 2002, PJM filed amendments to the OATT and to the OA to establish a permanent Emergency Load-Response Program (the Emergency Program).[64] By order dated April 30, 2002, the FERC approved the Emergency Program effective June 1, 2002. Like the Economic Program, a sunset date for it was set for December 1, 2004.[65] On October 29, 2004, the FERC extended the program until December 31, 2007, thereby making it coterminous with the Economic Program.[66] On February 24, 2006, the FERC approved changes to the PJM Tariff to make the Emergency Program permanent, including energy only and full emergency options.[67]

As a result of Reliability Pricing Model (RPM) implementation on June 1, 2007, the Emergency Program was modified to include an Emergency-Capacity Only option, to provide capacity credits to customers with Emergency-Full and Emergency-Capacity Only options, to make customers with the Emergency-Full option eligible for an Emergency-Energy payment for reductions during emergency events and to provide penalties for noncompliance during emergency events for customers with the Emergency-Full and Emergency-Capacity Only options.[68]

As part of the transition to RPM, effective June 1, 2007, the PJM active load management (ALM) program was changed to the load management (LM) program.[69] The LM program is comprised of two types of resources: ILR resources and demand resources (DR). Customers offering DR resources into an RPM Auction are paid the clearing price. Interruptible load for reliability (ILR) resources have to be certified at least three months prior to the delivery year and are paid the final zonal ILR price. An ILR resource can be registered under the Emergency-Capacity Only or Emergency-Full options of the Emergency and Economic Programs simultaneously. A DR resource can also be registered under the Emergency-Full option of the Emergency and Economic Programs simultaneously. However, a customer can participate in only one of the programs within an hour.

Customers with Emergency-Full and Emergency-Capacity Only options receive capacity credits on a daily basis. Customers with the Emergency-Full option are also eligible for an Emergency-Energy payment for reductions during emergency events. Customers with Emergency-Full and Emergency-Capacity Only options are obligated to respond during emergency events and face penalties for noncompliance.[70] The Emergency-Energy Only option is voluntary; customers who

62 One such inappropriate component was the payment of subsidies to customers who were already exposed to hourly LMP pricing.
63 *PJM Interconnection, L.L.C.,* Tariff Amendments, Docket No. ER02-1205-000 (March 1, 2002).
64 *PJM Interconnection, L.L.C.,* Tariff Amendments, Docket No. ER02-1205-000 (March 1, 2002).
65 99 FERC ¶ 61,139 (2002).
66 *PJM Interconnection, L.L.C.,* Letter Order, Docket No. ER04-1193-000 (October 29, 2004).
67 114 FERC ¶ 61,201 (February 24, 2006).
68 For additional information on RPM provisions for customers in the Emergency Load-Response Program, refer to PJM's "Manual 18: "PJM Capacity Market."
69 An LM program continues to have three types of products: direct load control, firm service level or guaranteed load drop. Each of the products continues to have two notification periods: short-lead time and long-lead time.
70 "Emergency-Full customers that failed to provide a load reduction dispatched by PJM shall be assessed the ALM Deficiency Charge. The ALM Deficiency Charge shall equal the lesser of the Compliance Deficiency Value multiplied by the Daily Capacity Deficiency Rate multiplied by 365/10, or the Compliance Deficiency value multiplied two times the Annual Value of the Capacity Credit divided by a factor of 5." PJM. "Manual 28: Operating Agreement Accounting," Revision 39 (January 1, 2008), p. 70.

register for this option do not have to reduce their load during emergency events. Credits are paid to Emergency-Energy Only customers in the event of load reductions.

In addition to dispatchable demand resources, future RPM auctions may include energy efficiency resources. On December 12, 2008, PJM submitted amendments to the OATT to allow "investments in energy efficiency to offer into and clear RPM auctions like any other resource," beginning with the May 2009 Base Residual Auction for the 2012/2013 delivery year.[71] The filing proposes that an energy efficiency resource be eligible to enter and clear in RPM auctions and receive the applicable auction clearing price for four consecutive years, since for the first four years of implementation, the energy efficiency project will not be fully recognized in the load forecast and thus the customer's Peak Load Contribution (PLC) will not reflect the lower energy usage.

Emergency Program

The zonal distribution of DSR capability in the Emergency-Energy Only option of the Emergency Program is shown in Table 2-86. On June 9, 2008, the peak-load day for the year, there were no available resources in the Emergency-Energy Only option of the Emergency Program.[72] There was no activity under this option in calendar year 2008.

Table 2-86 shows the zonal distribution of DSR capability in the Emergency-Full option and in the Emergency-Capacity option of the Emergency Program on June 9, 2008. The PSEG Control Zone included 16 percent of all registered sites under the Emergency-Full option, while the AEP Control Zone included 27 percent of all registered MW. The ComEd Control Zone included 54 percent of all registered sites and 32 percent of all registered MW in the capacity option of the Emergency Program.

71 *PJM Interconnection, L.L.C.*, Tariff Amendments, Docket No. ER09-412-000 (December 12, 2008).

72 The number of registered sites and MW levels are measured as a one-day snapshot. The one-day snapshot is used because retail customers may change curtailment service providers (CSP) multiple times within a year and each such change would require a registration. When switching occurs, an annual total of registered sites would count the same sites and MW multiple times.

Table 2-86 Zonal capability in the Emergency Program (By option): June 9, 2008

	Energy Only		Full		Capacity Only	
	Sites	MW	Sites	MW	Sites	MW
AECO	0	0.0	63	16.6	7	8.6
AEP	0	0.0	137	512.5	54	698.5
AP	0	0.0	100	138.9	39	133.7
BGE	0	0.0	189	422.1	46	32.8
ComEd	0	0.0	69	95.6	877	820.9
DAY	0	0.0	23	8.4	8	50.0
DLCO	0	0.0	13	27.0	21	45.6
Dominion	0	0.0	47	63.2	29	46.0
DPL	0	0.0	59	5.5	74	81.1
JCPL	0	0.0	79	97.6	33	14.5
Met-Ed	0	0.0	70	150.7	24	40.8
PECO	0	0.0	143	60.2	154	216.9
PENELEC	0	0.0	38	50.5	35	30.0
Pepco	0	0.0	31	23.1	35	21.3
PPL	0	0.0	113	58.5	97	278.7
PSEG	0	0.0	228	167.4	63	19.9
RECO	0	0.0	3	1.0	21	1.1
Total	0	0.0	1,405	1,898.8	1,617	2,540.4

In 2008, there were no days with emergency activity. Table 2-87 shows zonal monthly capacity credits that were paid during the calendar year 2008 to ILR and DR resources. Credits from January to May are associated with participation in the 2007/2008 RPM delivery year, while credits from June to December are associated with participation in the 2008/2009 RPM delivery year. The increase in capacity credits after May is the result of a significant increase in both DR and ILR participation in RPM delivery year 2008/2009, as well as changes in RPM clearing prices.

Table 2-87 Zonal monthly capacity credits: January 1, 2008, through December 31, 2008

Zone	January	February	March	April	May	June	July	August	September	October	November	December
AECO	$37,969	$35,520	$37,969	$36,745	$37,969	$149,566	$154,551	$154,551	$149,566	$154,551	$149,566	$154,551
AEP	$152,155	$142,339	$152,155	$147,247	$152,155	$2,494,967	$2,578,133	$2,578,133	$2,494,967	$2,578,133	$2,494,967	$2,578,133
AP	$142,290	$133,110	$142,290	$137,700	$142,290	$935,647	$966,835	$966,835	$935,647	$966,835	$935,647	$966,835
BGE	$1,169,116	$1,093,689	$1,169,116	$1,131,403	$1,169,116	$2,789,189	$2,882,161	$2,882,161	$2,789,189	$2,882,161	$2,789,189	$2,882,161
ComEd	$618,740	$578,821	$618,740	$598,781	$618,740	$3,188,324	$3,294,602	$3,294,602	$3,188,324	$3,294,602	$3,188,324	$3,294,602
DAY	$2,530	$2,366	$2,530	$2,448	$2,530	$250,552	$258,904	$258,904	$250,552	$258,904	$250,552	$258,904
DLCO	$2,909	$2,721	$2,909	$2,815	$2,909	$250,151	$258,489	$258,489	$250,151	$258,489	$250,151	$258,489
DOM	$14,292	$13,370	$14,292	$13,831	$14,292	$286,760	$296,319	$296,319	$286,760	$296,319	$286,760	$296,319
DPL	$349,317	$326,780	$349,317	$338,049	$349,317	$644,091	$665,561	$665,561	$644,091	$665,561	$644,091	$665,561
JCPL	$319,163	$298,575	$319,163	$308,867	$319,163	$537,656	$554,279	$554,279	$537,656	$554,279	$537,656	$554,279
Met-Ed	$55,145	$51,588	$55,145	$53,366	$55,145	$659,743	$681,734	$681,734	$659,743	$681,734	$659,743	$681,734
PECO	$1,068,079	$999,170	$1,068,079	$1,033,625	$1,068,079	$1,331,207	$1,375,581	$1,375,581	$1,331,207	$1,375,581	$1,331,207	$1,375,581
PENELEC	$1,897	$1,775	$1,897	$1,836	$1,897	$274,105	$283,241	$283,241	$274,105	$283,241	$274,105	$283,241
Pepco	$133,068	$124,483	$133,068	$128,776	$133,068	$553,703	$572,160	$572,160	$553,703	$572,160	$553,703	$572,160
PPL	$320,247	$299,586	$320,247	$309,917	$320,247	$1,161,825	$1,200,552	$1,200,552	$1,161,825	$1,200,552	$1,161,825	$1,200,552
PSEG	$620,717	$580,671	$620,717	$600,694	$620,717	$891,281	$922,290	$922,290	$891,281	$922,290	$891,281	$922,290
RECO						$9,890	$10,219	$10,219	$9,890	$10,219	$9,890	$10,219
Total	$5,007,634	$4,684,564	$5,007,634	$4,846,100	$5,007,634	$16,408,657	$16,955,611	$16,955,611	$16,408,657	$16,955,611	$16,408,657	$16,955,611

Economic Program

On June 9th, 2008, there were 2,294.7 MW registered in the Economic Program compared to the 2,498.03 MW on August 8, 2007, an 8.1 percent decrease. (See Table 2-88.)

Table 2-88 Economic Program registration: Within 2002 to 2008

	Sites	Peak-Day, Registered MW
14-Aug-02	96	335.4
22-Aug-03	240	650.6
03-Aug-04	782	875.6
26-Jul-05	2,548	2,210.2
02-Aug-06	253	1,100.7
08-Aug-07	2,897	2,498.0
09-Jun-08	956	2,294.7

Table 2-89 shows the zonal distribution of capability in the Economic Program on June 9, 2008. The PECO Control Zone includes 180 sites or 19 percent of sites and 9 percent of registered MW in the Economic Program. The BGE Control Zone includes 122 sites or 13 percent of sites and 26 percent of registered MW in the Economic Program. Program totals are subject to monthly and seasonal variation, as registrations begin, expire and renew. For example, the ComEd Control Zone showed a significant decrease in registered sites and MW when comparing peak days for 2008 and 2007.

On June 30, 2008, ComEd Control Zone registrations increased to 2,221 sites accounting for 835.9 registered MW, compared to the 83 sites and 137.5 MW registered on the 2008 peak load day.

Table 2-89 Zonal capability in the Economic Program: June 9, 2008

	Sites	MW
AECO	32	11.0
AEP	10	248.7
AP	25	186.2
BGE	122	601.6
ComEd	83	137.5
DAY	2	5.0
DLCO	44	181.2
Dominion	111	125.6
DPL	20	90.2
JCPL	48	115.4
Met-Ed	32	69.2
PECO	180	212.1
PENELEC	10	11.3
Pepco	15	16.3
PPL	74	203.2
PSEG	145	79.5
RECO	3	0.7
Total	956	2,294.7

The total MWh of load reduction and the associated payments under the Economic Program are shown in Table 2-90.[73] Load reduction levels decreased to 452,222 MWh in calendar year 2008.[74] Payments per MWh were $60 in 2008 compared to $74 in 2007. The Economic Program's actual load reduction per peak-day, registered MW decreased to 197.1 MWh for calendar year 2008, a decrease of 31 percent from 2007.[75] In the calendar year 2008, the maximum hourly load reduction attributable to the Economic Program was 493.6 MW on June 10.

73 The "Total MWh" and "Total Payments" for the Economic Program shown here are also subject to subsequent settlement adjustments in 2009.

74 The Economic Program payments and MWh presented in this report do not include all settlement adjustments for 2007 and 2008. The data are provided by PJM's DSR department; Economic Program payments and MWh reductions are based on the January, 2009, PJM billing information and are subject to adjustments.

75 The "Total MWh" and "Total Payments" for calendar year 2007 are different from those reported in the *2007 State of the Market Report*, as a result of adjusted settlements. The "Total MWh" increased by 105,403 MWh and the "Total Payments" increased by $3,860,339.

Table 2-90 Performance of PJM Economic Program participants

	Total MWh	Total Payments	$/MWh	Total MWh per Peak-Day, Registered MW
2002	6,727	$801,119	$119	20.1
2003	19,518	$833,530	$43	30.0
2004	58,352	$1,917,202	$33	66.6
2005	157,421	$13,036,482	$83	71.2
2006	258,468	$18,584,013	$72	234.8
2007	714,148	$49,033,576	$74	285.9
2008	452,222	$27,087,495	$60	197.1

While total MWh reductions are down by 261,926 or 36.7 percent, total payments are down by $21.9 million or 44.8 percent compared to 2007, meaning that there was a significant decrease in payments per MWh reduction. However, this is partially due to the sunset of the economic incentive program in November of 2007.[76] Table 2-91 shows total MWh reductions and payments less incentive payments.[77] Excluding the incentive portion, total payments fell $4.5 million, or 14.3 percent, from $31.6 million to $27.1 million, while payments per MWh of reduction increased from $44 per MWh in 2007 to $60 per MWh in 2008. Figure 2-20 shows monthly non-incentive economic program payments for 2007 and 2008. Economic Program credits have consistently declined since June of 2008. This is partially due to the CBL revisions effective June 12, 2008 and the newly implemented activity review process effective November 3, 2008. In addition, December credits are likely understated due to the lag associated with the submittal and processing of settlements.[78]

Table 2-91 Performance of PJM Economic Program participants without incentive payments

	Total MWh	Total Payments	$/MWh
2002	6,727	$801,119	$119
2003	19,518	$833,530	$43
2004	58,352	$1,917,202	$33
2005	157,421	$13,036,482	$83
2006	258,468	$10,213,828	$40
2007	714,148	$31,600,046	$44
2008	452,222	$27,087,495	$60

76 In 2006 and 2007, when LMP was greater than, or equal to, $75 per MWh, customers were paid the full LMP and the amount not paid by the LSE, equal to the generation and transmission components of the applicable retail rate (recoverable charges), was charged to all LSEs in the zone of the load reduction. As of December 31, 2007, the incentive payments totaled $17,391,099, an increase of 108 percent from calendar year 2006. No incentive credits were paid in November and December 2007 because the total exceeded the specified cap.

77 Settlement data for 2007 including reductions, credits and incentive payments data received from PJM DSR group February 2, 2009.

78 Settlements may be submitted up to 60 days following an event day. EDC/LSEs have up to 10 business days to approve which could account for a maximum lag of approximately 74 calendar days.

Figure 2-20 Economic Program Payments: Calendar years 2007 (without incentive payments) and 2008

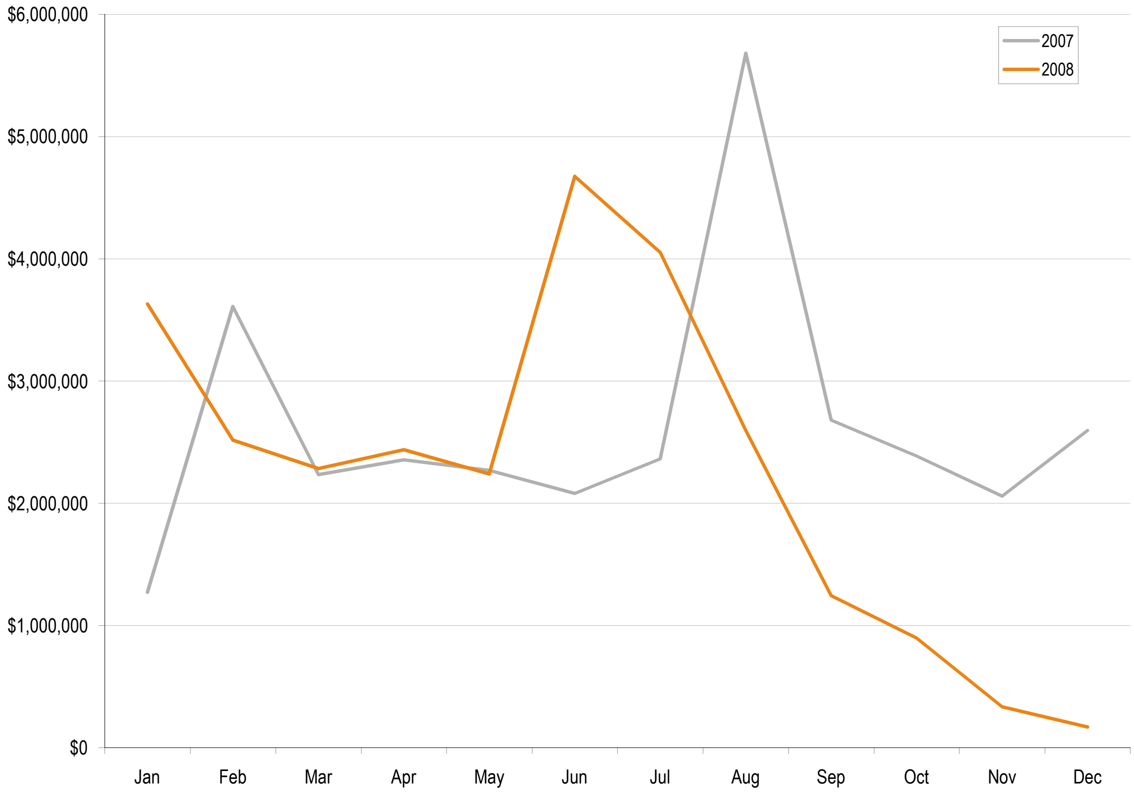


Table 2-92 shows 2008 performance in the Economic Program by control zone and participation type. The total number of curtailed hours for the Economic Program was 272,671 and the total payment amount was $27,087,495.[79] Overall, approximately 95 percent of the MWh reductions, 95 percent of payments and 88 percent of curtailed hours resulted from the real-time, self scheduled option of the Economic Program. Approximately 2 percent of the MWh reductions, 2 percent of payments and 1 percent of curtailed hours resulted from the day-ahead option.[80] Approximately 3 percent of the MWh reductions, 3 percent of the payments and 11 percent of the curtailed hours resulted from the dispatched in real time option of the program. (See Table 2-92.) PECO Control Zone accounted for $12.9 Million or 47.6 percent of all Economic Program credits, associated with 220,979 or 51.3 percent of total program reduction hours.

79 If two different retail customers curtail during the same hour in the same zone, it is counted as two curtailed hours.

80 On February 2, 2007, PJM proposed to the FERC that customers with day-ahead, LMP-based contracts be eliminated from participation in the day-ahead Economic Program. On June 15, 2007, the Commission issued an order, 119 FERC ¶ 61,280, rejecting PJM's proposed revision to its OATT.

Table 2-92 PJM Economic Program by zonal reduction: Calendar year 2008

	Real Time			Day Ahead			Dispatched in Real Time			Totals		
	MWh	Credits	Hours	MWh	Credits	Hours	MWh	Credits	Hours	MWh	Credits	Hours
AECO	190	$15,721	613	0	($118)	52	1,894	$78,852	1,267	2,083	$94,454	1,932
AEP	6,402	$256,595	484	4,252	$167,984	158	28	$3,834	11	10,681	$428,412	653
AP	18,215	$1,172,390	8,151	109	$4,590	242	193	$22,494	306	18,517	$1,199,473	8,699
BGE	4,911	$980,181	1,735	0	($12)	16	1	$30	56	4,912	$980,198	1,807
ComEd	23,987	$806,728	17,070	115	$4,198	43	6,261	$178,222	10,462	30,364	$989,148	27,575
DAY	2,073	$129,082	464				3	$163	6	2,076	$129,245	470
DLCO	35,330	$3,047,127	35,426	0	$83	10	455	$69,723	3,412	35,785	$3,116,933	38,848
Dominion	139	$18,312	675	0	$11	10	8	$54	266	148	$18,378	951
DPL	4,294	$114,225	974				13	$2,261	6	4,307	$116,487	980
JCPL	690	$107,259	548	0	($194)	70	181	$9,911	657	871	$116,976	1,275
Met-Ed	1,791	$97,486	1,237	28	$2,922	114	82	$7,072	403	1,902	$107,480	1,754
PECO	220,979	$12,673,642	142,308	4	$336	66	1,948	$227,551	9,379	222,931	$12,901,529	151,753
PENELEC	1,320	$45,450	771				94	$4,365	412	1,413	$49,815	1,183
Pepco	4,380	$240,208	790	0	($9)	10	476	$32,944	1,421	4,856	$273,143	2,221
PPL	104,908	$5,969,539	26,148	4,890	$427,588	1,400	636	$70,120	2,800	110,435	$6,467,246	30,348
PSEG	935	$98,644	2,015	0	($317)	134	1	$122	12	936	$98,448	2,161
RECO	5	$163	21	0	($34)	40				5	$129	61
Total	430,550	$25,772,752	239,430	9,399	$607,026	2,365	12,273	$707,717	30,876	452,222	$27,087,495	272,671
Max	220,979	$12,673,642	142,308	4,890	$427,588	1,400	6,261	$227,551	10,462	222,931	$12,901,529	151,753
Avg	25,326	$1,516,044	14,084	671	$43,359	169	767	$44,232	1,930	26,601	$1,593,382	16,039

Table 2-93 shows a frequency distribution of MWh reductions and credits at each hour for calendar year 2008. The period from hour ending 0800 EPT to 2300 EP accounts for 82.9 percent of MWh reductions and 88.9 percent of credits.

Table 2-93 Hourly frequency distribution of Economic Program MWh reductions and credits: Calendar year 2008

	MWh Reductions				Program Credits			
Hour	MWh Reductions	Percent	Cumulative Frequency	Cumulative Percent	Credits	Percent	Cumulative Frequency	Cumulative Percent
1	8,463	1.87%	8,463	1.87%	$293,368	1.08%	$293,368	1.08%
2	7,693	1.70%	16,155	3.57%	$259,091	0.96%	$552,460	2.04%
3	7,446	1.65%	23,601	5.22%	$217,326	0.80%	$769,786	2.84%
4	6,956	1.54%	30,558	6.76%	$196,816	0.73%	$966,602	3.57%
5	8,248	1.82%	38,806	8.58%	$229,140	0.85%	$1,195,742	4.41%
6	10,752	2.38%	49,558	10.96%	$366,991	1.35%	$1,562,733	5.77%
7	15,887	3.51%	65,445	14.47%	$1,073,345	3.96%	$2,636,078	9.73%
8	19,520	4.32%	84,965	18.79%	$1,188,912	4.39%	$3,824,990	14.12%
9	21,343	4.72%	106,308	23.51%	$1,029,934	3.80%	$4,854,923	17.92%
10	22,159	4.90%	128,468	28.41%	$1,130,251	4.17%	$5,985,175	22.10%
11	23,864	5.28%	152,332	33.69%	$1,402,151	5.18%	$7,387,325	27.27%
12	23,164	5.12%	175,496	38.81%	$1,337,262	4.94%	$8,724,587	32.21%
13	24,317	5.38%	199,813	44.18%	$1,481,200	5.47%	$10,205,787	37.68%
14	25,487	5.64%	225,300	49.82%	$1,659,776	6.13%	$11,865,563	43.80%
15	26,154	5.78%	251,454	55.60%	$1,811,141	6.69%	$13,676,704	50.49%
16	25,741	5.69%	277,195	61.30%	$1,997,403	7.37%	$15,674,107	57.86%
17	27,051	5.98%	304,246	67.28%	$2,293,169	8.47%	$17,967,276	66.33%
18	28,255	6.25%	332,501	73.53%	$2,422,544	8.94%	$20,389,820	75.27%
19	25,178	5.57%	357,679	79.09%	$1,623,219	5.99%	$22,013,039	81.27%
20	23,613	5.22%	381,292	84.32%	$1,465,585	5.41%	$23,478,624	86.68%
21	23,319	5.16%	404,611	89.47%	$1,594,456	5.89%	$25,073,080	92.56%
22	20,275	4.48%	424,887	93.96%	$1,119,104	4.13%	$26,192,184	96.69%
23	15,251	3.37%	440,138	97.33%	$520,459	1.92%	$26,712,642	98.62%
24	12,084	2.67%	452,222	100.00%	$374,853	1.38%	$27,087,495	100.00%

Table 2-94 shows the frequency distribution of Economic Program MWh reductions and credits by real-time zonal, load-weighted, average LMP in price ranges of $15 per MWh. Reductions occurred primarily when zonal, load-weighted, average LMP was between $30 and $135 per MWh. Approximately 57.4 percent of MWh reductions and 27.7 percent of program credits are associated with hours when the applicable zonal LMP was less than or equal to $90.

Table 2-94 Frequency distribution of Economic Program zonal, load-weighted, average LMP (By hours): Calendar year 2008

	MWh Reductions				Program Credits			
LMP	MWh Reductions	Percent	Cumulative Frequency	Cumulative Percent	Credits	Percent	Cumulative Frequency	Cumulative Percent
$0 to $15	10	0.00%	10	0.00%	$24,175	0.09%	$24,175	0.09%
$15 to $30	5,554	1.23%	5,564	1.23%	$25,101	0.09%	$49,277	0.18%
$30 to $45	37,723	8.34%	43,287	9.57%	$520,211	1.92%	$569,488	2.10%
$45 to $60	72,453	16.02%	115,740	25.59%	$1,556,315	5.75%	$2,125,803	7.85%
$60 to $75	77,818	17.21%	193,558	42.80%	$2,469,899	9.12%	$4,595,702	16.97%
$75 to $90	65,871	14.57%	259,430	57.37%	$2,915,585	10.76%	$7,511,286	27.73%
$90 to $105	47,571	10.52%	307,000	67.89%	$2,822,030	10.42%	$10,333,317	38.15%
$105 to $120	37,609	8.32%	344,609	76.20%	$2,707,346	9.99%	$13,040,662	48.14%
$120 to $135	29,150	6.45%	373,759	82.65%	$2,492,222	9.20%	$15,532,884	57.34%
$135 to $150	18,177	4.02%	391,936	86.67%	$1,780,902	6.57%	$17,313,787	63.92%
$150 to $165	15,437	3.41%	407,373	90.08%	$1,714,648	6.33%	$19,028,435	70.25%
$165 to $180	12,219	2.70%	419,593	92.78%	$1,547,170	5.71%	$20,575,605	75.96%
$180 to $195	6,807	1.51%	426,399	94.29%	$948,983	3.50%	$21,524,589	79.46%
$195 to $210	5,517	1.22%	431,917	95.51%	$863,014	3.19%	$22,387,602	82.65%
$210 to $225	4,193	0.93%	436,109	96.44%	$692,955	2.56%	$23,080,557	85.21%
$225 to $240	3,701	0.82%	439,810	97.26%	$682,771	2.52%	$23,763,328	87.73%
$240 to $255	2,089	0.46%	441,899	97.72%	$421,676	1.56%	$24,185,004	89.28%
$255 to $270	2,054	0.45%	443,953	98.17%	$440,102	1.62%	$24,625,106	90.91%
$270 to $285	1,564	0.35%	445,517	98.52%	$350,231	1.29%	$24,975,337	92.20%
$285 to $300	1,201	0.27%	446,718	98.78%	$291,846	1.08%	$25,267,183	93.28%
$300 to $315	714	0.16%	447,432	98.94%	$165,974	0.61%	$25,433,157	93.89%
$315 to $330	736	0.16%	448,169	99.10%	$199,831	0.74%	$25,632,988	94.63%
$330 to $345	492	0.11%	448,661	99.21%	$138,750	0.51%	$25,771,738	95.14%
$345 to $360	601	0.13%	449,261	99.35%	$190,984	0.71%	$25,962,722	95.85%
$360 to $375	131	0.03%	449,392	99.37%	$40,636	0.15%	$26,003,358	96.00%
$375 to $390	377	0.08%	449,768	99.46%	$118,611	0.44%	$26,121,969	96.44%
$390 to $405	178	0.04%	449,947	99.50%	$57,513	0.21%	$26,179,481	96.65%
$405 to $420	134	0.03%	450,081	99.53%	$32,948	0.12%	$26,212,429	96.77%
$420 to $435	344	0.08%	450,425	99.60%	$125,084	0.46%	$26,337,513	97.23%
$435 to $450	44	0.01%	450,469	99.61%	$15,083	0.06%	$26,352,596	97.29%
$450 to $465	331	0.07%	450,800	99.69%	$127,507	0.47%	$26,480,103	97.76%
$465 to $480	286	0.06%	451,086	99.75%	$109,688	0.40%	$26,589,791	98.16%
$480 to $495	95	0.02%	451,181	99.77%	$36,386	0.13%	$26,626,178	98.30%
$495 to $510	524	0.12%	451,704	99.89%	$222,398	0.82%	$26,848,575	99.12%
$510 to $525	23	0.01%	451,727	99.89%	$10,491	0.04%	$26,859,066	99.16%
$525 to $540	261	0.06%	451,989	99.95%	$118,563	0.44%	$26,977,629	99.59%
> $540	234	0.05%	452,222	100.00%	$109,867	0.41%	$27,087,495	100.00%

Active Load Management (ALM) and Load Management (LM)

Table 2-95 shows the available ALM MW for 2002 to 2006 and the available LM MW for 2007 and 2008.

Table 2-95 Available ALM MW and LM MW: Within 2002 to 2008

	2002	2003	2004	2005	2006	2007	2008
1-Jun	1,342	1,265	1,412	2,035	1,655	2,140	4,414
1-Jul	1,304	1,255	1,228	2,042	1,679	2,145	4,498
1-Aug	1,285	1,156	1,226	2,042	1,679	2,145	4,498
1-Sep	1,275	1,158	1,224	2,038	1,678	2,145	4,498

Price Impacts of Demand-Side Response

The price impact of demand-side response can be calculated in a number of ways. Prior to the *2006 State of the Market Report*, the MMU calculated the price impact using the aggregate summer PJM supply curve, as this represents the actual offers of PJM resources. However, the actual real-time prices in PJM reflect the fact that resources are not completely flexible and that the aggregate supply curve does not always reflect real-time limitations on the ability to dispatch available generation resources. Beginning with the *2006 State of the Market Report*, real-time hourly supply curves were developed for the period from June to September from actual PJM prices and corresponding loads, which represent the relationship between prices and loads in PJM for this time period. This method is straightforward and reproducible by any market analyst. The 2008 analysis showed that a reduction of 1 MW resulted in a price reduction of approximately $0.0025 per MW.

Issues and Program Changes

Customer Base Line (CBL) - History

Participants in the Economic Program are paid based upon the reductions in MWh usage that can be attributed to demand side actions and measures. Most participants in the Economic Program measure their reductions by comparing metered load against an estimate of what metered load would have been absent the reduction.[81] The general methodology is to create a base line usage level by calculating the average usage for a set of days that are intended to be representative of a retail customer's typical usage, including separate calculations for weekends/holidays. The extent to which the DSR Program can accurately quantify and compensate actual load reductions is dependent on the Program's ability to establish what a customer's metered load would have been absent any load reduction. This is a very difficult task and the methods used to date have been flawed, resulting in payments for reductions in usage that did not occur.

81 On-site generation meter data is the other method used to determine the load reduction, if used only for economic load reduction.

Since the beginning of the program, there have been significant issues with the approach to measuring demand-side response MW. An inaccurate or unrepresentative CBL can lead to payments when the customer has taken no action to respond to market prices. Substantial improvement in measurement and verification methods must be implemented in order to ensure the credibility of PJM demand-side programs. These could take the form of improvements in the CBL calculation and/or improvements in the verification and customer documentation of load reducing activities. The goal should be to treat the measurement of demand-side resources like the measurement of any other resource in the wholesale power market, including generation and load, that is paid by other participants or makes payments to other participants. Recent changes to the settlement review process represent clear improvements, but do not go far enough.

Prior to recent process revisions, the electricity distribution company (EDC) or LSE was responsible for reviewing a customer's CBL data and could object to the calculations. When an EDC or LSE objected, customers had time to resubmit the data, which were also subject to review. From the beginning of the Economic Program, there were multiple settlement disputes in which an EDC or LSE did not approve CBL calculations and CSPs requested PJM involvement. These disputes were among the factors that led to the creation of the Customer Base Line Subcommittee (CBLS) in January 2007. The subcommittee's mission was to "Evaluate current methodology for PJM economic load response used to determine load reductions done through deliberate customer actions in response to expected day ahead and/or real time prices…[and] propose enhancements and/or changes that will improve the transparency and accuracy of the results which will also help to reduce the number of unanticipated settlement rejections."[82]

In December 2007, proposals to modify CBL business rules were presented to the PJM Market Implementation Committee with a focus on two major issues: the permissible period for selecting a comparable day and the number of days to be used for the CBL calculation; and the definition of a demand-side curtailment. The key criteria considered by the CBLS were empirical performance, simplicity, eliminating gaming/free-ridership, and overall cost to implement and administer.

On April 14, 2008, PJM filed with the FERC revisions to the Tariff and Operating Agreement to improve the Economic Program.[83] The filing included provisions to: (1) improve the method of establishing CBLs; (2) clarify that eligibility is limited to demand reductions in response to price; (3) establish objective criteria to assist with the identification of inappropriate market activity; and (4) provide PJM the authority to deny participation in the Program. Revisions were approved June 12, 2008.[84]

The revised, current weekday CBL methodology includes the highest four of most recent five weekdays, with a maximum lag on eligible days set at 45. Low usage days (load less than 75 percent of the average) and event days (days with curtailment events or demand reductions) are eliminated and replaced with prior days, unless there are not enough eligible days in the last 45 weekdays. Saturdays are considered separately, as are Sundays and holidays. The elimination of event days means that CBL measurements are not limited to the most recent five weekdays and can include weekdays from as far back as 45 days.

82 "Customer Baseline Committee Charter," February 27, 2007, <http://www.pjm.com/~/media/committees-groups/subcommittees/cbls/postings/20070223-final-charter.ashx> (22.7 KB).
83 *PJM Interconnection, L.L.C.,* Tariff Amendments, Docket No. ER08-824-000 (April 14, 2008).
84 123 FERC ¶ 61,257 (2008).

Prior to the revisions, the standard weekday CBL included the highest five weekdays of the most recent 10 weekdays, with no limit on how current CBL days must be. In addition, low usage days were defined as load less than 25 percent of average usage. Submitted settlement days were considered event days in CBL calculations even if they were eventually denied. Saturdays, Sundays and holidays were all considered “like days”.

The effect of the revisions approved June 12, 2008 was to provide for CBL calculations based on more recent and comparable data, which has made CBL calculations more representative of retail customers’ load absent any reduction activities. Additionally, the provision clarifying that participation is limited to reductions in response to real time prices and the establishment of PJM’s authority to deny participation were necessary program changes that are essential components of a rational verification process.

CBL - Issues

Even after the revisions, the CBL is still a simple, generic formula applied to nearly every customer’s usage and, as such, is not adequate to serve as the sole or primary basis for determining if an intentional load reduction took place. There are no mandatory CBL enhancements for customers with highly volatile load patterns.[85] If a customer normally has lower load on one particular weekday, that day will appear as a reduction eligible for payment under the current CBL methodology although no deliberate load reducing actions were taken in response to real time price signals. There are no adjustments for load levels that are a function of weather. In a mild week following a week of extreme temperatures and high load levels, a customer can submit settlements without taking any load reducing action and it will appear as a reduction eligible for payment because metered load is below CBL. There is no requirement in the DSR Program to periodically review CBLs to ensure that they are representative of customer load patterns. The only trigger for a CBL review in the program is a participation level greater than 70 percent in a rolling 30 weekday period.

The MMU has analyzed all settlement data submitted in the economic load response program from the period July 1 through November 1, 2008, to assess the revised CBL calculation.[86] While the revised CBL showed significant improvements in representing load patterns, the revised CBL methodology is still inadequate as a basis for defining and determining load reductions which are compensated under the PJM demand side programs. The tariff changes effective June 13, 2008, provide for a thirty day period to review activity in the Economic Load Response Program, after which, “the Office of the Interconnection may refer the matter to the PJM MMU and/or the FERC Office of Enforcement if the review indicates the relevant Economic Load Response Participant and/or relevant electric distribution company or LSE is engaging in activity that is inconsistent with the PJM Interchange Energy Market rules governing Economic Load Response Participants.”[87] PJM has not referred any participants or registrations to the MMU.

Determining the accuracy of a CBL is a difficult task. More data is required than the metered load associated with settlement and the CBL used to determine the reduction amount. However, that is the only data currently available to PJM at the time of settlement review. Complete historical data is required in order to determine whether the CBL is representative of normal load patterns. The

85 An alternative CBL can be developed if agreed upon by both the relevant LSE/EDC and the CSP.

86 Since behind the meter generation customers do not require a CBL, they were excluded from this analysis.

87 Section 3.3A.7

small number of hours of settlement data is not adequate. Prior to November 2008, many CSPs and customers routinely submitted settlements data in excess of what was needed to perform the settlement function. While this placed an administrative burden on PJM and the relevant LSEs/EDCs, one unintended result was that PJM had more complete load data for many customers.

Analysis of Settlements

The revised PJM settlement review process includes screens that will result in reduced submissions of excess settlement data.[88] While this is a positive change for the program, it limits the hourly metered load data available to PJM and thus limits the ability to assess whether a customer's CBL is representative. The MMU has evaluated CBL calculations for the period between the implementation of the CBL revisions and the implementation of the PJM Activity Review Process, when these data were still available.

Daily settlement submissions prior to November 2008 typically contained all 24 hours of data per day. In the period from July 1, 2008 through October 31, 2008, there were 12,067 daily settlements submitted, of which, 7,577, or 62.8 percent, included 24 hours of data. Of those 7,577 settlement days, 2,571 or 33.9 percent, showed a CBL greater than metered load for all 24 hours of the settlement day (Table 2-96). These settlements account for 41.9 percent of all economic payments for the period.

Table 2-96 Settlements showing consecutive 24 hour reductions as a percent of total settlements submitted for the period July 1, 2008 through October 31, 2008

	Settlement Days	Percent of Total Settlements	CSP Credits	Percent of Total Credit
24 consecutive hours CBL > Metered Load	2,571	21.3%	$3,165,418	41.9%
All other Settlements	9,496	78.7%	$4,381,443	58.1%
Total	12,067	100.0%	$7,546,861	100.0%

It is extremely implausible that any customer, let alone this proportion of customers, would take load reduction actions for 24 consecutive hours in response to real time price signals. It is also extremely implausible that an accurate CBL would result in metered load less than base line load for every hour of the day. It is more likely that the CBL is biased upward because it is based on usage from prior days with higher load. Under these circumstances, it is impossible to determine whether the customer took any load reducing actions, from the settlement data. It is the MMU's recommendation that any settlement submitted with a consecutive 24 hour period of CBL greater than metered load should initiate a CBL review by PJM and that a customer should be required to provide documentation of load reduction actions taken prior to acceptance of such settlements.

The PJM Activity Review Process has significantly reduced the occurrence of 24 hour settlement submissions and therefore the frequency of 24 consecutive hours where the CBL is greater than metered load. However, there are still instances of requests for settlements passing the daily activity review screen while including 24 consecutive hours of reduction and these settlements are paid without any documentation of load reducing activities in response to real time price signals.

88 Specifically, the normal operations screen and the requirement that notification hours match settlement hours have resulted in a reduction of the submission of excess settlement data.

In the period November 1, 2008 through December 31, 2008, there were 3,027 settlement days submitted, of which, 638 or 21.1 percent contained all 24 hours of data. Of those 638 24-hour settlement days, 304, or 47.6 percent, show a CBL greater than metered load for all 24 hours. Of those 304 settlements, 151 were denied by PJM, while the remaining 153 were approved and account for $23,757 or 18.4 percent of Economic Program Credits for the period. While the frequency of consecutive 24 hour settlements has been significantly reduced, the proportion of those settlements that show a reduction for all 24 hours is higher at 47.6 than in the prior period when it was 33.9 percent.

In addition to submitting settlement claims for 24 consecutive hour periods, customers frequently submitted settlements for consecutive days. Prior to November 2008, many customers submitted settlement data for a large proportion of all available hours in a given month.

While the behavior is questionable, the resultant data permits a detailed analysis of customer behavior during this period. During the period July 1, 2008 through October 31, 2008, of the 223,830 settlement hours submitted, 184,627, or 82.5 percent, showed a CBL greater than the hourly metered load. Table 2-97 shows the number of actual settlement hours submitted as a percent of total hours in the period for the ten customers with the highest number of settlement hours from July 1, 2008 through October 31, 2008. Under the current CBL calculation, Customer A claimed to have reduced load for 75.5 percent of all available hours, peak and off peak, during the 123 day period. The top seven customers show CBL greater than metered load for more than 50 percent of the hours in the 123 day period. These settlements account for $1.1 Million or 14.9 percent of total CSP credits paid to load-reducing customers for the period.

The new PJM "normal operations" screen specifically targets this type of behavior and the frequency of consecutive daily settlement submission has dropped significantly since November 2008.

It is extremely implausible that any customer, let alone this proportion of customers, would take load reduction actions in response to real time price signals for more than 50 percent of the hours in a period covering approximately four months. It is also extremely implausible that an accurate CBL would result in metered load less than base line load for more than 50 percent of the hours in a period covering approximately four months. It is more likely that the CBL is biased upward because it is based on usage from prior days with higher load. The data also appear to show that even after the CBL revisions effective June 13, 2008, an upwardly biased CBL can result. Under these circumstances, it is impossible to determine whether the customer took any load reducing actions based only on the submitted settlement data.

Table 2-97 Ten highest submitting customers' data summary from the period July 1, 2008 through October 31, 2008

	Hours in Period	Hours Submitted	Percent of hours submitted	Hours CBL > metered load	Percent CBL> metered load of submitted	Percent CBL> metered load of all period hours	CSP Credits
Customer A	2,952	2,319	78.6%	2,228	96.1%	75.5%	$83,710
Customer B	2,952	2,230	75.5%	2,092	93.8%	70.9%	$739,166
Customer C	2,952	2,036	69.0%	1,886	92.6%	63.9%	$19,707
Customer D	2,952	2,030	68.8%	1,831	90.2%	62.0%	$101,495
Customer E	2,952	2,018	68.4%	1,804	89.4%	61.1%	$13,556
Customer F	2,952	1,954	66.2%	1,878	96.1%	63.6%	$8,983
Customer G	2,952	1,805	61.1%	1,611	89.3%	54.6%	$11,894
Customer H	2,952	1,796	60.8%	1,458	81.2%	49.4%	$5,660
Customer I	2,952	1,774	60.1%	1,630	91.9%	55.2%	$131,134
Customer J	2,952	1,773	60.1%	1,278	72.1%	43.3%	$8,133
Summary	29,520	19,735	66.9%	17,696	89.7%	59.9%	$1,123,440

Activity Review Process

Effective November 3, 2008, PJM began a new activity review process for settlements in the Economic Demand Side Response Program.[89] The activity review process includes a daily screen and a "normal operations" screen for identifying inappropriate behavior. In addition, the activity review process specifically defines the acceptable criteria for LSE/EDC denial of settlements. LSE/EDCs can no longer deny settlements based on whether the customer's CBL calculations reasonably represent load or on a determination that a load reduction action was not in response to price. While it is reasonable to limit the authority of LSE/EDCs in the review of demand side settlements as the LSE/EDCs have economic incentives to deny settlements, LSE/EDCs should be able to initiate PJM settlement reviews.

The daily screen provides that PJM will deny a daily settlement when any of the following criteria are met: (1) no advanced notification for settlements; (2) settlement hours do not match notification hours; (3) settlement is worth less than $5 in value; or (4) 75 percent or more of settlement hours show a retail generation and transmission rate higher than LMP.

The daily screen does indirectly address an issue with the CBL calculation, the ineligibility of "event days" for inclusion in CBL. When a high CBL results from high load days, a customer or CSP could submit settlements on daily basis to block lower load days from CBL eligibility, creating an upward bias in measured CBL. When a customer submits low value settlements for the purpose of blocking the inclusion of low load days from the CBL, the daily review process will deny them if they fail one of the four identified screens. But, PJM will not review daily settlements to assess responsiveness to price or accuracy of the CBL.

89 <http://www.pjm.com/Media/committees-groups/committees/drsc/20081031-item-04-dsr-activity-review-proc.pdf>

PJM's "normal operations" screen involves a review of all participation when a customer submits settlements for 70 percent (21 days) of available days in a rolling 30 weekday period. The review includes: (1) analysis of notifications and settlements; (2) review of registration contract; (3) required CSP submission of detailed description of load reduction activities; (4) written verification from end-use customer regarding DSR activity on specific days; and (5) optional on-site review. During this review, all new settlement requests will be denied pending the outcome of the review. Depending on the conclusion of the activity review, the registration may be terminated and the CSP may be referred to the FERC Office of Enforcement and/or the MMU, pursuant to the tariff.

Conclusions

Table 2-98 shows the number of customers and revenue by settlement days for the period July 1, 2008 through October 31, 2008. The Table shows the number of customers and the amount of revenue that would have been affected by the new normal operations screen for the period. The period included 123 days and the customers were grouped by their maximum number of settlement days for any 30 rolling weekday period. If the normal operations screen had been active for the period, 122 customers or 33.8 percent of active customers would have sufficient activity to warrant a review. These customers account for $6.9 Million or 91.4 percent of total program credits for the period.

Table 2-98 Distribution of customers and credits at various levels of settlement days in rolling 30 weekday basis

Settlement days in 30 rolling weekday period	Customers	Percent Customer	Percent Customer Cumulative	Credits	Percent Credit	Percent Credit Cumulative	Credit per Customer
1	22	6.4%	6.5%	$7,530	0.1%	0.1%	$342
2	20	5.8%	12.4%	$18,616	0.2%	0.3%	$931
3	8	2.3%	14.7%	$41,598	0.6%	0.9%	$5,200
4	6	1.7%	16.8%	$67,413	0.9%	1.8%	$11,236
5	12	3.5%	19.7%	$9,993	0.1%	1.9%	$833
6	6	1.7%	21.2%	$29,450	0.4%	2.3%	$4,908
7	5	1.5%	22.4%	$1,467	0.0%	2.3%	$293
8	6	1.7%	24.1%	$3,708	0.0%	2.4%	$618
9	6	1.7%	25.9%	$1,266	0.0%	2.4%	$211
10	8	2.3%	28.2%	$14,929	0.2%	2.6%	$1,866
11	11	3.2%	31.5%	$48,108	0.6%	3.2%	$4,373
12	11	3.2%	34.7%	$13,130	0.2%	3.4%	$1,194
13	12	3.5%	38.2%	$7,880	0.1%	3.5%	$657
14	17	5.0%	43.2%	$39,830	0.5%	4.0%	$2,343
15	13	3.8%	47.1%	$10,880	0.1%	4.2%	$837
16	12	3.5%	50.6%	$29,336	0.4%	4.6%	$2,445
17	12	3.5%	54.1%	$40,092	0.5%	5.1%	$3,341
18	16	4.7%	58.8%	$55,788	0.7%	5.8%	$3,487
19	8	2.3%	61.2%	$74,102	1.0%	6.8%	$9,263
20	10	2.9%	64.1%	$136,075	1.8%	8.6%	$13,607
21	7	2.0%	66.2%	$170,542	2.3%	10.9%	$24,363
22	8	2.3%	68.5%	$191,699	2.5%	13.4%	$23,962
23	9	2.6%	71.2%	$86,369	1.1%	14.6%	$9,597
24	19	5.5%	77.1%	$1,956,292	25.9%	40.5%	$102,963
25	17	5.0%	82.1%	$2,795,841	37.0%	77.5%	$164,461
26	17	5.0%	87.1%	$114,195	1.5%	79.1%	$6,717
27	14	4.1%	91.2%	$52,542	0.7%	79.8%	$3,753
28	11	3.2%	94.4%	$320,519	4.2%	84.0%	$29,138
29	4	1.2%	95.3%	$125,368	1.7%	85.7%	$31,342
30	16	4.7%	100.0%	$1,082,303	14.3%	100.0%	$67,644
Summary	343	100.0%		$7,546,861	100.0%		$22,003

The modifications to the CBL calculations and the new review process are significant improvements to the Economic Program, but the review process is not yet adequate to ensure that other customers are receiving the benefit of actual demand reductions when payments are made under the program. The new review process is not yet developed to the point that it can establish that load reductions are the result of identifiable load reducing actions taken in response to price. There is no explicit or implicit screening mechanism in place to verify that CBL calculations are representative of customer load.

The “normal operations” screen defines an explicit threshold for the proportion of available days submitted for settlement, at or above which the CSP and end use customer must substantiate their submitted demand reductions. It is not clear why it is appropriate to require documentation of load reduction activities above a threshold and require no documentation of load reduction activities below that threshold.

The definition of CBL should continue to be refined to ensure that it reflects the actual normal use of individual customers including normal daily and hourly fluctuations in usage and usage that is a function of measurable weather conditions.

The MMU recommends two ways to further improve the program by increasing the probability that payments are made only for economic and deliberate load reducing activities in response to price.

- Load reduction in response to price must be clearly defined in the business rules and verified in a transparent daily settlement screen.

- The four steps in the normal operations review should be routinely applied to all registrations from the beginning of participation. This would include the ongoing evaluation of whether CBL accurately represents customer load for each customer; analysis of settlements to determine responsiveness to price and; required submission of detailed description of load reduction activities on specific days.

SECTION 3 – ENERGY MARKET, PART 2

The Market Monitoring Unit (MMU) analyzed measures of PJM Energy Market structure, participant conduct and market performance for 2008. As part of the review of market performance, the MMU analyzed the net revenue performance of PJM markets, the characteristics of existing and new capacity in PJM, the definition and existence of scarcity conditions in PJM and the performance of the PJM operating reserve construct.

Overview

Net Revenue

- **Net Revenue Adequacy.** Net revenue is an indicator of generation investment profitability and thus is a measure of overall market performance as well as a measure of the incentive to invest in new generation to serve PJM markets. Net revenue quantifies the contribution to capital cost received by generators from all PJM markets. Although it can be expected that in the long run, in a competitive market, net revenue from all sources will cover the fixed costs of investing in new generating resources, including a competitive return on investment, actual results are expected to vary from year to year. Wholesale energy markets, like other markets, are cyclical. When the markets are long, prices will be lower and when the markets are short, prices will be higher.

  Overall, 2008 net revenue showed mixed results compared to 2007. For the new entrant combustion turbine (CT), all zones showed an increase in net revenue compared to 2007, which in many cases reflects lower energy revenue offset by increased capacity revenue. For the new entrant combined cycle (CC), all zones showed an increase in net revenue compared to 2007, which reflects an increase in energy and capacity market revenue in most eastern zones and an increase in just capacity market revenue in most western zones. For the new entrant coal plant (CP), most zones showed an increase in net revenue compared to 2007, which in many cases reflects lower energy market revenue offset by increased capacity market revenue. The levels of net revenue in 2008 for these new peaking, midmerit and coal-fired baseload power plants vary significantly by location. Higher energy market prices were offset by higher generation costs, and as a result, there were several zones for each technology that showed a decrease in energy market net revenue, despite higher price levels. However, revenues associated with the sale of capacity resources increased for all zones in 2008 as the Reliability Pricing Model (RPM) construct was in effect for a full calendar year. The fixed costs of constructing a combined-cycle generation resource were fully covered in some, but not all, PJM control zones. The fixed costs of constructing a combustion turbine were 99 percent covered by net revenues in AECO and Pepco Control Zones and 93 percent covered in the BGE Control Zone. There were no zones with revenue adequacy for the CP technology despite the full year of RPM capacity payments, as a result of increased fuel costs. The results from 2008 highlight the significance of the RPM construct's contribution to capital cost recovery and to the incentive to invest in new PJM generation resources in years when energy market and ancillary service revenues are inadequate to cover the costs of this investment.

Zonal net revenue reflects differences in locational energy prices and differences in locational capacity prices. The zonal variation in net revenue illustrates the substantial impact of location on economic incentives. While the 2008 net revenue using PJM real-time average locational marginal prices (LMPs) was $50,532 per MW-year for a CT, the zonal maximum net revenue was $122,845 in the Pepco Control Zone and the minimum was $33,727 in the AEP Control Zone.[1] While the PJM average net revenue in 2008 was $103,928 per MW-year for a CC, the zonal maximum net revenue was $219,105 in the Pepco Control Zone and the minimum was $61,141 in the DLCO Control Zone. While the PJM average net revenue in 2008 was $218,144 per MW-year for a CP, the zonal maximum net revenue was $397,620 in the Pepco Control Zone and the minimum was $160,462 in the DAY Control Zone.

Existing and Planned Generation

- **PJM Installed Capacity.** During the period January 1, through December 31, 2008, PJM installed capacity resources rose slightly from 164,277 MW on January 1 to 164,895 MW on December 31.

- **PJM Installed Capacity by Fuel Type.** Of the total installed capacity at the end of 2008, 40.7 percent was coal; 29.3 percent was natural gas; 18.5 percent was nuclear; 6.5 percent was oil; 4.5 percent was hydroelectric; 0.4 percent was solid waste, and 0.1 percent was wind.

- **Generation Fuel Mix.** During 2008, coal provided 55.0 percent, nuclear 34.6 percent, gas 7.3 percent, oil 0.3 percent, hydroelectric 1.7 percent, solid waste 0.7 percent and wind 0.5 percent of total generation.

- **Planned Generation.** If current trends continue, it is expected that older steam units in the east will be replaced by units burning natural gas and the result has potentially significant implications for future congestion, the role of firm and interruptible gas supply and natural gas supply infrastructure.

Scarcity

- **Scarcity Pricing Events in 2008.** PJM did not declare a scarcity event in 2008.

- **Scarcity.** A wholesale energy market will not consistently result in adequate revenues in the absence of a carefully designed and comprehensive approach to scarcity pricing. This is a result, not of offer capping, but of the fundamentals of wholesale power markets which must carry excess capacity in order to meet externally imposed reliability rules.

  Scarcity revenues to generation owners can come entirely from energy markets or they can come from a combination of energy and capacity markets. The RPM capacity market design reflects the recognition that the energy markets, by themselves and in the absence of a carefully

1 Calculated values shown in Section 3, "Energy Market, Part 2," are based on unrounded, underlying data and may differ from calculations based on the rounded values shown in tables.

designed expansion of scarcity pricing, will not result in adequate revenues. The RPM design provides an alternate method for collecting scarcity revenues.

The revenues in the capacity market are scarcity revenues. If the revenues collected in the RPM market are adequate, it is not essential that a scarcity pricing mechanism exist in the energy market. Nonetheless, it would be preferable to have a scarcity pricing mechanism in the energy market because it provides direct, market-based incentives to load and generation, as long as the market rules are designed to ensure that scarcity revenues directly offset RPM revenues to prevent double collection of scarcity revenues.

A hybrid market design can provide scarcity revenues both via scarcity pricing in the energy market and via the capacity market. However, if scarcity revenues are provided in the energy market, there must be an explicit mechanism to remove those revenues from capacity market revenues. This offset must reflect the actual scarcity revenues and not those reflected in forward curves or forecast by analysts from any organization. The absence of such a mechanism is likely to result in an over collection of scarcity revenues as such revenues are episodic and unlikely to be fully reflected in forward curves, even if such curves were based on a liquid market three years forward and reflected locational results, which they do not. The most straightforward way to ensure that such over collection does not occur would be to ensure that capacity resources do not receive scarcity revenues in the energy market in the first place. The settlements process can remove any scarcity revenues from payments to capacity resources and eliminate the need for a complex, uncertain, after the fact procedure for offsetting scarcity revenues in the capacity market.

- **Modifications to Scarcity Pricing.** While PJM's triggers for administrative scarcity pricing are reasonable measures of scarcity conditions, PJM's scarcity pricing rules need refinement. In addition, PJM should consider creating a mechanism for defining new scarcity pricing regions in real time if system conditions warrant.

  The current single scarcity price signal should be replaced by locational signals. Locational scarcity signals could be implemented via reserve requirements modeled as constraints for scarcity regions, with administrative scarcity penalty factors, in the security constrained dispatch. The level of the penalty factor and the reserve target would be determined by the severity level of the scarcity event. This would provide a means to signal scarcity that is consistent with economic dispatch, consistent with locational pricing and consistent with competitive market outcomes.

  Administrative scarcity pricing should include stages, based on system conditions, with progressive impacts on prices. The trigger for each stage should be based on the level of available operating reserve using a dynamically determined and relevant operating reserve requirement and the progressive use of emergency measures. Implemented as scarcity region specific operating reserve constraints in the security constrained dispatch, the severity of scarcity event should be reflected in a set of increasing, administrative penalty factors.

  If implemented using reserve requirement constraints with escalating penalty factors, the scarcity pricing mechanism would eliminate the need to lift offer capping during a scarcity pricing event. Properly set, the penalty factors would increase prices on the system to provide a locational pricing signal reflecting the severity of the shortage. This approach also eliminates the incentive for participants to make non-competitive energy offers in anticipation of scarcity events. Keeping offers consistent during the event would have the added benefit of avoiding the operational issues involved with sudden changes in the economic dispatch order before, during and after a scarcity event.

Credits and Charges for Operating Reserve

- **Operating Reserve Issues.** Day-ahead and real-time operating reserve credits are paid to generation owners under specified conditions in order to ensure that units are not required to operate for the PJM system at a loss. Sometimes referred to as uplift or revenue requirement make whole, operating reserve payments are intended to be one of the incentives to generation owners to offer their energy to the PJM Energy Market at marginal cost and to operate their units at the direction of PJM dispatchers. From the perspective of those participants paying operating reserve charges, these costs are an unpredictable and unhedgeable component of the total cost of energy in PJM. While reasonable operating reserve charges are an appropriate part of the cost of energy, market efficiency would be improved by ensuring that the level of operating reserve charges is as low as possible consistent with the reliable operation of the system and that the allocation of operating reserve charges reflects the reasons that the costs are incurred.

- **Operating Reserve Charges in 2008.** The level of operating reserve credits and corresponding charges decreased in 2008 by 6.5 percent compared to 2007. This was the result of a large decrease in the amount of synchronous condensing operating reserve credits, a smaller decrease in the amount of balancing operating reserve credits and an increase in the amount of day-ahead operating reserve credits.

- **New Operating Reserve Rules in 2008.** New rules governing the payment of operating reserves credits and the allocation of operating reserves charges became effective on December 1, 2008. The new operating reserve rules represent positive steps towards the goals of removing the ability to exercise market power and refining the allocation of operating reserves charges to better reflect causal factors.

Conclusion

Wholesale electric power markets are affected by externally imposed reliability requirements. A regulatory authority external to the market makes a determination as to the acceptable level of reliability which is enforced through a requirement to maintain a target level of installed or unforced capacity. The requirement to maintain a target level of installed capacity can be enforced via a variety of mechanisms, including government construction of generation, full-requirement contracts with developers to construct and operate generation, state utility commission mandates to construct capacity, or capacity markets of various types. Regardless of the enforcement mechanism, the exogenous requirement to construct capacity in excess of what is constructed in response to energy market signals has an impact on energy markets. The reliability requirement results in maintaining a level of capacity in excess of the level that would result from the operation of an energy market alone. The result of that additional capacity is to reduce the level and volatility of energy market prices and to reduce the duration of high energy market prices. This, in turn, reduces net revenue to generation owners which reduces the incentive to invest.

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 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 in well-defined stages with transparent triggers and 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. With a capacity market design that appropriately reflects a direct and explicit offset for scarcity rents in the energy market, 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.

A capacity market is a formal mechanism, with both administrative and market-based components, used to allocate the costs of maintaining the level of capacity required to maintain the reliability target. A capacity market is an explicit mechanism for valuing capacity and is preferable to non market and nontransparent mechanisms for that reason.

While net revenue in PJM has been almost sufficient to cover the costs of new peaking units in some years and was sufficient to cover the costs of a new coal plant in 2005 and close to covering those costs in 2006 in some eastern zones, net revenue prior to the RPM construct was generally below the level required to cover the full costs of new generation investment for several years and below that level on average for all unit types for the entire market period. The fact that investors' expectations have not been realized in every year could be taken as a reflection of cyclical supply-demand fundamentals in PJM markets. However, it is also the case that there have been some units in PJM, needed for reliability, with revenues less than annual going-forward costs, which, if it persists, is a signal to retire. This suggests that market price signals and reliability needs have not been fully synchronized.

The historical level of net revenues in PJM markets is not the result of the $1,000-per-MWh offer cap, of local market power mitigation, or of a basic incompatibility between wholesale electricity markets and competition. Competitive markets can, and do, signal scarcity and surplus conditions through market-clearing prices. Nonetheless, in PJM as in other wholesale electric power markets, the application of reliability standards means that scarcity conditions in the Energy Market occur with reduced frequency. Traditional levels of reliability require units that are only directly used and priced under relatively unusual load conditions. Thus, the Energy Market alone frequently does not directly value the resources needed to provide for reliability, although the contribution of the Energy Market will be more consistent with reliability signals if the Energy Market appropriately provides for scarcity pricing when scarcity does occur.

PJM's RPM is an explicit effort to address these issues. RPM is a Capacity Market design intended to send supplemental signals to the market based on the locational and forward-looking need for generation resources to maintain system reliability in the context of a long-run competitive equilibrium in the Energy Market.

The combination of locational Energy Market and locational Capacity Market signals in 2007 represented a significant change from market performance over prior years. The combined locational prices clearly signaled a need for and an incentive for investment in eastern zones where there is a demonstrated need for new capacity, although the results vary by technology. In 2007, net revenues exceeded the costs of all technologies in the BGE and Pepco Control Zones and net revenues exceeded the costs of CC technology in seven eastern control zones.

In 2008, market results were mixed. The cost of fuel inputs eroded the increased revenue from higher price levels, but that effect was less significant in some constrained eastern control zones. The result is that while the Energy Market Net Revenues alone are insufficient to recover capital costs in any control zone, when combined with RPM Capacity revenue, total net revenue in several eastern zones is sufficient to cover the investment costs of a new entrant combined cycle plant and total net revenue in three eastern zones are approximately sufficient to cover the investment costs of a new entrant combustion turbine.

The net revenue results illustrate some fundamentals of the PJM wholesale power market. CTs are generally the highest incremental cost units and therefore tend to be marginal in the energy market and set prices, when they run. When this occurs, CT energy market net revenues are small and there is little contribution to fixed costs. High demand hours result in less efficient CTs setting prices, which results in higher net revenues for more efficient CTs. There were relatively few high demand days in 2008. Scarcity revenues in the energy market contribute to covering fixed costs, when they occur, but scarcity revenues are not a predictable and systematic source of net revenue. In the PJM design, the balance of the net revenue required to cover the fixed costs of peaking units comes from the Capacity Market. However, when the actual fixed costs of capacity increase rapidly, there is a corresponding lag in Capacity Market prices which will tend to lead to an under recovery of the fixed costs of CTs. That is what occurred in 2008. The fixed costs of a CT in 2008 are substantially higher than the fixed costs of a CT in 2007, but the clearing prices in the Capacity Market reflect the prior, lower costs of a CT that were incorporated in the demand curve for the auctions that determined prices in the 2007/2008 and 2008/2009 RPM auctions.

The net revenue performance of combined cycle units (CCs) was significantly better than that of CTs. CCs, like CTs, burn gas but are more efficient than CTs and therefore as clearing prices set by CTs increase, net revenues from the Energy Market increase for CCs. These inframarginal energy revenues were the source of the higher CC net revenues in 2008.

Coal units (CP) are marginal in the PJM system for a substantial number of hours. When this occurs, CP energy market net revenues are small and there is little contribution to fixed costs. When less efficient coal units are on the margin net revenues are higher for more efficient coal units. Coal units also receive higher net revenues as a result of CTs setting prices based on higher gas costs, when they run.

The ultimate test of a competitive market design is whether it provides incentives to invest that are acted upon by market participants, based on incentives endogenous to the competitive market design and not in reliance on the potential or actual exercise of market power. The net revenue performance of the Real-Time Energy Market, the Day-Ahead Energy Market and the Capacity Market prior to 2007 illustrated that additional market modifications were necessary if PJM were to pass that test. The performance of the markets in 2007 and 2008, especially the Capacity Markets, represented a significant improvement over prior performance. The reaction of investors will determine whether the market design modifications are successful.

Net Revenue

Net revenue is an indicator of generation investment profitability, and thus is a measure of overall market performance as well as a measure of the incentive to invest in new generation to serve PJM markets. Net revenue quantifies the contribution to capital cost received by generators from PJM Energy, Capacity and Ancillary Service Markets and from the provision of black start and reactive services. Although generators receive operating reserve payments as a revenue stream, these payments are not included when the analysis is based on perfect dispatch.[2] Operating reserve payments are included, when the analysis is based on the peak-hour, economic dispatch model on any days when a unit operated at a loss.[3]

Gross Energy Market revenue is the product of the Energy Market price and generation output. Gross revenues are also received from the Capacity and Ancillary Service Markets. Total gross revenue less variable cost equals net revenue. In other words, net revenue is the amount that remains, after variable costs have been subtracted from gross revenue, to cover fixed costs which include a return on investment, depreciation, taxes and fixed operation and maintenance expenses.

The net revenues presented in this section are theoretical as they are based on explicitly stated assumptions about how a unit would operate, rather than on an analysis of actual net revenues for actual units operating in PJM. Energy Market net revenues were developed separately for both the Real-Time and the Day-Ahead Energy Markets.

In a perfectly competitive, energy-only market in long-run equilibrium, net revenue from the energy market would be expected to equal the total of all fixed costs for the marginal unit, including a competitive return on investment. The PJM market design includes other markets intended to contribute to the payment of fixed costs. In PJM, the Energy, Capacity and Ancillary Service Markets are all significant sources of revenue to cover fixed costs of generators, as are payments for the provision of black start and reactive services. Thus, in a perfectly competitive market in long-run equilibrium, with energy, capacity and ancillary service payments, net revenue from all sources would be expected to equal the fixed costs of generation for the marginal unit. Net revenue is a measure of whether generators are receiving competitive returns on invested capital and of whether market prices are high enough to encourage entry of new capacity. In actual wholesale power markets, where equilibrium seldom occurs, net revenue is expected to fluctuate based on actual conditions in all relevant markets.

Theoretical Energy Market Net Revenue

The Real-Time Energy Market revenues in Table 3-1 and the Day-Ahead Energy Market revenues in Table 3-2 reflect net Energy Market revenues from all hours during 1999 to 2008 for the Real-

2 Under the PJM model, operating reserve payments compensate generation owners when units operate at PJM's request when LMP is less than marginal cost over defined hours of operation. Operating reserve does not apply in perfect dispatch because the theoretical unit only operates when LMP is greater than marginal cost.

3 The peak-hour, economic dispatch model is a realistic representation of market outcomes that, in contrast to the perfect dispatch model, considers unit operating limits. The model can result in the dispatch of a unit for a block that yields negative net energy revenue and is made whole by operating reserve payments.

Time Energy Market and during 2000 to 2008 for the Day-Ahead Energy Market when the PJM hourly LMP exceeded the identified marginal cost of generation. The tables include the dollars per installed MW-year that would have been received by a unit in PJM if it had operated whenever system price exceeded the identified marginal cost in dollars per MWh, adjusted for unit forced outages.[4] For example, during 2008, if a unit had marginal costs (fuel plus variable operation and maintenance expense) equal to $30 per MWh, it had an incentive to operate whenever the Real-Time Energy Market LMP exceeded $30 per MWh. If such a unit had operated during all profitable hours in 2008, adjusted for forced outages, it would have received $302,122 per installed MW-year in net revenue from the Real-Time Energy Market alone. For the Day-Ahead Energy Market, the same unit would have received $295,084 per installed MW-year in net revenue from the Day-Ahead Energy Market.[5]

Table 3-1 illustrates the relationship between generator marginal cost and net revenue from the PJM Real-Time Energy Market alone for the years 1999 through 2008.

Table 3-1 PJM Real-Time Energy Market net revenue (By unit marginal cost (Dollars per MWh)): Calendar years 1999 to 2008

Marginal Cost	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
$10	$152,087	$150,774	$186,887	$153,620	$231,927	$263,115	$394,619	$322,668	$388,984	$459,738
$20	$94,690	$89,418	$116,116	$85,661	$159,751	$185,956	$314,917	$242,179	$308,397	$379,750
$30	$72,489	$59,776	$78,368	$51,898	$110,126	$121,218	$241,977	$171,735	$235,215	$302,122
$40	$62,367	$39,519	$56,055	$31,650	$73,828	$74,920	$184,479	$120,014	$177,918	$233,568
$50	$57,080	$25,752	$42,006	$19,776	$47,277	$44,577	$141,078	$83,857	$132,033	$179,669
$60	$54,132	$16,888	$33,340	$13,101	$29,566	$25,328	$107,057	$58,812	$95,768	$138,282
$70	$52,259	$11,750	$27,926	$9,080	$18,001	$13,624	$80,473	$41,608	$67,644	$106,343
$80	$50,959	$8,586	$24,389	$6,623	$10,650	$6,929	$59,903	$29,643	$46,859	$81,666
$90	$49,840	$6,700	$22,080	$5,079	$6,273	$3,494	$44,043	$21,585	$32,467	$62,360
$100	$48,818	$5,640	$20,521	$4,109	$3,770	$1,784	$32,184	$16,188	$23,110	$47,397
$110	$47,863	$4,930	$19,375	$3,507	$2,250	$951	$23,338	$12,653	$16,898	$35,713
$120	$46,926	$4,385	$18,480	$3,063	$1,315	$518	$16,831	$10,283	$12,655	$26,971
$130	$46,007	$3,958	$17,716	$2,758	$723	$260	$12,070	$8,645	$9,795	$20,281
$140	$45,114	$3,609	$17,030	$2,501	$387	$124	$8,528	$7,466	$7,737	$15,222
$150	$44,228	$3,317	$16,421	$2,287	$218	$51	$5,903	$6,667	$6,302	$11,288
$160	$43,374	$3,102	$15,884	$2,115	$142	$24	$3,946	$6,030	$5,202	$8,351
$170	$42,523	$2,923	$15,395	$1,970	$94	$9	$2,554	$5,508	$4,357	$6,196
$180	$41,685	$2,768	$14,944	$1,828	$51	$0	$1,679	$5,083	$3,722	$4,630
$190	$40,856	$2,623	$14,542	$1,700	$23	$0	$1,113	$4,699	$3,219	$3,464
$200	$40,036	$2,488	$14,162	$1,607	$10	$0	$706	$4,347	$2,831	$2,643

4 Real-Time and Day-Ahead Energy Market net revenue calculations reflect a forced outage rate equal to the actual PJM system forced outage rate for each year. Since these tables include a range of marginal cost from $10 to $200, an outage rate by class cannot be utilized because there is no simple mapping of marginal cost to class of generation, e.g. the $100 marginal cost could include steam-oil, gas–fired CC and efficient gas-fired CTs. Class-specific forced outage rates are used for the class-specific net revenue calculations.

5 This unit would not receive Real-Time Energy Market revenues in addition to Day-Ahead Energy Market revenues as any energy scheduled in the Day-Ahead Energy Market would be credited at the day-ahead energy market-clearing price and would not be eligible for Real-Time Energy Market revenues for the same hour of operation.

Table 3-2 illustrates the relationship between generator marginal cost and net revenue from the PJM Day-Ahead Energy Market alone for the years 2000 through 2008.[6]

Table 3-2 PJM Day-Ahead Energy Market net revenue (By unit marginal cost (Dollars per MWh)): Calendar years 2000 to 2008

Marginal Cost	2000	2001	2002	2003	2004	2005	2006	2007	2008
$10	$158,429	$189,366	$154,267	$234,622	$254,455	$392,425	$216,637	$364,734	$456,557
$20	$95,823	$115,372	$83,083	$159,572	$176,265	$311,563	$165,614	$283,295	$375,221
$30	$61,816	$68,718	$44,916	$102,907	$109,583	$235,006	$117,447	$207,702	$295,084
$40	$38,762	$42,283	$25,011	$61,674	$59,650	$173,084	$77,340	$146,320	$221,678
$50	$23,141	$27,936	$15,126	$34,891	$27,638	$125,929	$47,954	$97,297	$161,374
$60	$14,281	$20,375	$9,894	$19,169	$11,152	$90,176	$29,201	$59,674	$115,287
$70	$9,523	$16,304	$6,804	$10,504	$4,039	$63,340	$18,423	$34,135	$80,996
$80	$6,840	$13,933	$4,856	$5,858	$1,375	$43,467	$12,613	$19,326	$56,349
$90	$5,100	$12,540	$3,522	$3,389	$415	$29,224	$9,180	$11,257	$39,159
$100	$3,927	$11,478	$2,570	$1,954	$121	$19,208	$7,037	$6,530	$27,761
$110	$3,244	$10,705	$1,885	$1,150	$42	$12,186	$5,742	$3,730	$20,157
$120	$2,683	$10,098	$1,385	$620	$14	$7,409	$4,873	$2,081	$14,650
$130	$2,299	$9,579	$1,000	$315	$0	$4,361	$4,203	$1,167	$10,633
$140	$2,056	$9,139	$712	$148	$0	$2,397	$3,628	$703	$7,706
$150	$1,884	$8,708	$494	$34	$0	$1,229	$3,136	$421	$5,594
$160	$1,787	$8,312	$354	$0	$0	$574	$2,703	$241	$4,034
$170	$1,701	$7,926	$243	$0	$0	$234	$2,314	$118	$2,929
$180	$1,616	$7,564	$145	$0	$0	$83	$1,991	$51	$2,173
$190	$1,532	$7,232	$78	$0	$0	$31	$1,717	$11	$1,611
$200	$1,447	$6,908	$30	$0	$0	$11	$1,475	$0	$1,209

Figure 3-1 displays the information from Table 3-1, and Figure 3-2 displays the information from Table 3-2. As Figure 3-1 illustrates, the Real-Time Energy Market net revenue curve was higher in 2008 than in 2007 for every level of unit marginal costs up to and including $200 per MWh. For units with marginal costs equal to, or less than, $90, net revenues were higher in 2008 than in any other year since PJM introduced markets in 1999. As Figure 3-2 illustrates, the Day-Ahead Energy Market net revenue curve was higher in 2008 than in 2007 for every marginal cost level up to and including $200. For units with marginal costs equal to, or less than, $130, net revenues were higher in 2008 than in any other year since PJM introduced the Day-Ahead Energy Market in 2000.

The increase in 2008 Real-Time Energy Market net revenue compared to 2007 is the result of changes in the frequency distribution of energy prices. In 2008, prices were greater than, or equal to, $30 per MWh more frequently than in 2007. The 2008 simple average LMP was $66.40 per MWh, a substantial increase compared to $57.58 per MWh in 2007. In 1999, the Real-Time Energy

6 The Day-Ahead Energy Market began on June 1, 2000. For the analysis presented in Table 3-2, Real-Time Energy Market LMP was used from January 1, 2000, to May 31, 2000.

Market LMP was greater than, or equal to, $30 per MWh during 17 percent of all hours. In 2000, this was 29 percent; in 2001, 34 percent; in 2002, 30 percent; in 2003, 51 percent; in 2004, 68 percent; 81 percent in 2005; 74 percent in 2006; 79 percent in 2007, and 92 percent in 2008.

The increase in 2008 compared to 2007 Day-Ahead Energy Market net revenue is also the result of changes in the frequency distribution of energy prices. In 2008, prices were greater than, or equal to, $30 more frequently than in 2007 as the simple average LMP was $66.12 per MWh in 2008 compared to $54.67 per MWh in 2007. In 2000, the Day-Ahead Energy Market LMP was greater than or equal to $30 per MWh during 42 percent of all hours. In 2001, this was 42 percent; in 2002, 33 percent; in 2003, 60 percent; in 2004, 72 percent; in 2005, 86 percent; in 2006, 80 percent; in 2007, 84 percent and in 2008, 96 percent.

The distribution of prices reflects a number of factors including load levels and fuel costs. Load levels in 2008 were close to those in 2007, while fuel costs increased significantly. An efficient CT could have produced energy at an average cost of $30 in 1999, compared to $90 in 2007 and $110 in 2008. An efficient CC could have produced energy at an average cost of $20 in 1999, compared to $55 in 2007 and $70 in 2008. An efficient CP could have produced energy at an average cost of $20 in 1999, but $25 in 2007 and $45 in 2008. Average price levels in 2008 were significantly higher than in 2007 and, as a result, net revenue levels were higher for specific marginal cost levels, as shown in Figure 3-1 and Figure 3-2. However, these higher average price levels reflect higher costs associated with operating base-load, mid-merit and peaking generation resources, and Energy Market net revenues for a new entrant CT, CC and CP were mixed in 2008 despite higher PJM price levels. From 2007 to 2008, the average prices of natural gas and delivered coal increased more rapidly than did the PJM RTO average LMP. The result is that average PJM prices in 2008 were higher than they were in 2007, while natural gas-fired units and coal-fired units experienced relatively higher marginal costs compared to 2007, meaning lower energy net revenue in many control zones for 2008.

Figure 3-1 PJM Real-Time Energy Market net revenue (By unit marginal cost): Calendar years 1999 to 2008

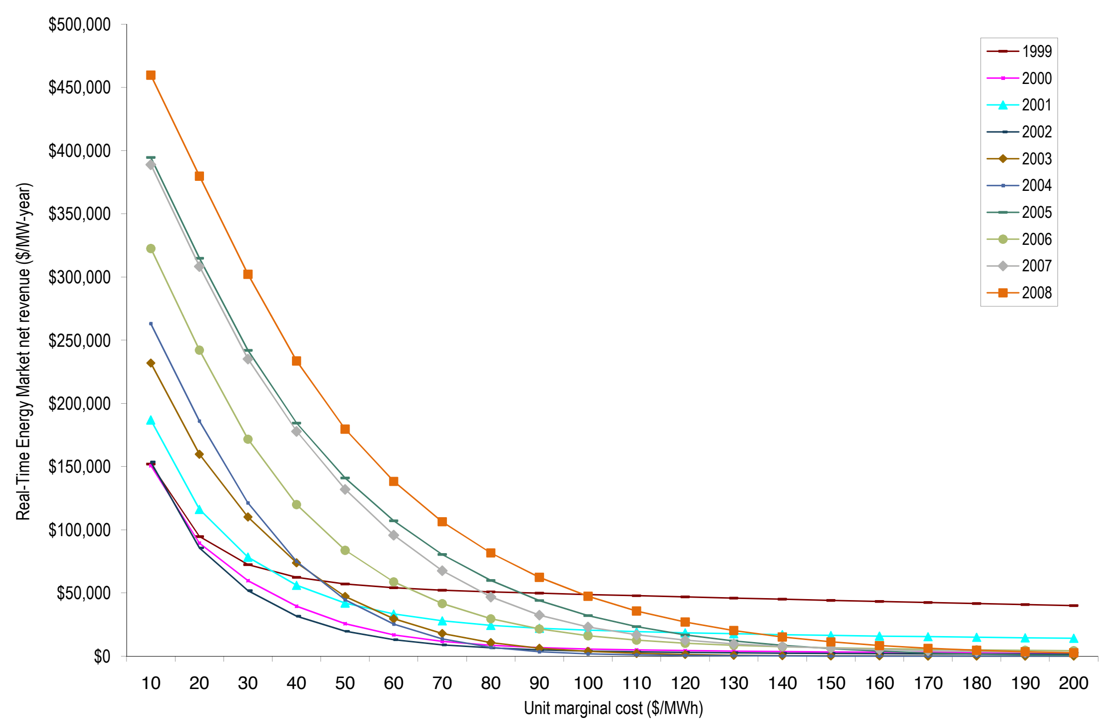
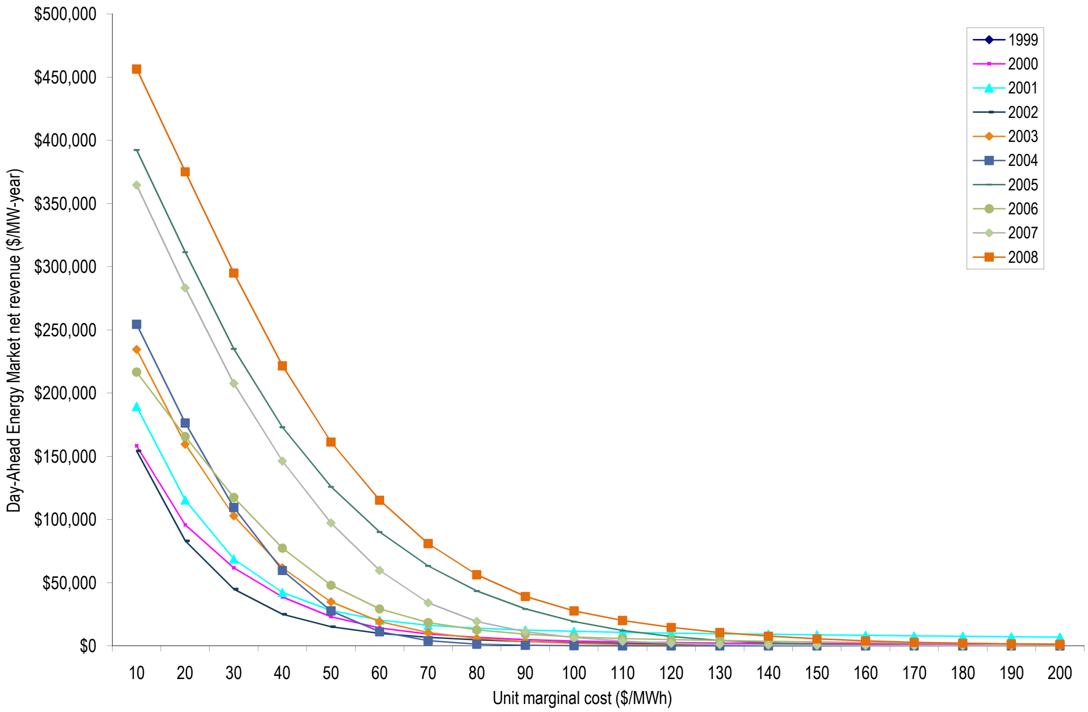


Figure 3-2 PJM Day-Ahead Energy Market net revenue (By unit marginal cost): Calendar years 2000 to 2008



Differences in the shape and position of Real-Time and Day-Ahead Energy Market net revenue curves result from different distributions of Energy Market prices in each year. These differences illustrate, among other things, the significance of a relatively small number of high-priced hours to the profitability of high marginal cost units.[7]

The theoretical net revenues displayed in Table 3-1 and Table 3-2 are calculated under perfect dispatch assumptions and therefore represent an upper bound of the direct contribution to generator fixed costs from the Energy Market. All other things constant, these Energy Market net revenues show how the frequency distribution of price levels in a given year affects the amount of revenue a generator would have received at the specified levels of marginal cost.

The Energy Market net revenues shown in Table 3-1 and Table 3-2 do not consider operating constraints that may affect actual net revenue of an individual plant. Such operating constraints are less likely to affect the net revenue calculations for CTs, given their operational flexibility and the operating reserve revenue guarantee. For a CC steam plant, a two-hour hot status notification plus startup time for a summer weekday could prevent a unit from running during two positive net revenue hours in the afternoon peak and two more positive net revenue hours in the evening peak separated by two negative net revenue hours, or could result in reduced net revenues from the negative net revenue hours.[8] The actual impact depends on the relationship between LMP and the operating cost of the unit. Similarly, a CP steam plant with an eight-hour cold status notification

7 See the *2008 State of the Market Report*, Volume II, Section 2, "Energy Market, Part 1," at "Load and LMP" and Appendix C, "Energy Market" for detailed data on prices and their annual distribution.

8 A two-hour hot start, including a notification period, is consistent with the CC technology.

plus startup time could run overnight during negative net revenue hours although the lower relative operating costs of a steam unit would generally reduce the significance of the issue.[9] Ramp limitations might prevent a CC or steam unit from starting and ramping up to full output in time to operate for all positive net revenue hours.

Conversely, the net revenue measure does not include the potentially significant contribution to fixed cost from the explicit or implicit sale of the option value of physical units or from bilateral agreements to sell output at a price other than the PJM Day-Ahead or Real-Time Energy Market prices, e.g., a forward price.

Capacity Market Net Revenue

Generators receive revenue from the sale of capacity in addition to revenue from the Energy and Ancillary Service Markets. In the PJM market design, the sale of capacity provides an important source of revenues to cover generator fixed costs. The Capacity Credit Market (CCM) design was in effect until June 1, 2007. For the period from January 1, through May 31, 2007, PJM capacity resources received a weighted-average payment from the CCM of $3.21 per MW-day of unforced capacity, a total of $485 per MW for the five-month period, or $1,172 per MW-year on an annualized basis. This is the lowest level of CCM revenues since the opening of the CCM in mid-1999.

On June 1, 2007, with the implementation of the RPM, PJM capacity resources began to receive a daily capacity payment of an amount determined by the first RPM Auction (June 1, 2007, through May 31, 2008) for their corresponding locational delivery area (LDA). For the first RPM Auction, there were three LDAs with three separate prices: RTO, which cleared at $40.80 per MW-day; Eastern Mid-Atlantic Area Council (EMAAC), which cleared at $197.67 per MW-day; and Southwestern Mid-Atlantic Area Council (SWMAAC), which cleared at $188.54 per MW-day. For the period January 1, 2008 through May 31, 2008, this revenue steam totaled $6,202 per MW in the RTO, $30,046 per MW in EMAAC and $28,658 per MW in SWMAAC. The second RPM auction clearing prices, applied from June 1, 2008 through December 31, 2008, were: $111.92 per MW-day for RTO or $23,951 per MW for the remainder of 2008, $148.80 per MW-day for EMAAC or $31,843 per MW for the remainder of 2008 and $210.11 per MW-day in SWMAAC or $44,964 for the remainder of 2008. Calendar year 2008 capacity revenues are a sum of five months or 152 days at the first auction clearing prices and seven months or 214 days at the second auction clearing prices. These revenues are shown by zone and LDA in Table 3-3.[10]

9 An eight-hour cold status notification plus startup is consistent with the CP technology.

10 Capacity revenues in Table 3-3 show total potential revenues available through RPM per installed MW-year and are not adjusted with a forced outage rate. Capacity revenues in Table 3-4 do reflect an adjustment for the system forced outage rate.

Table 3-3 2008 PJM RPM auction-clearing capacity price and capacity revenue by LDA and zone: Effective for January 1, through December 31, 2008

		Delivery Year 2007/2008		Delivery Year 2008/2009		
Zone	LDA	$/MW-Day	$/MW in 2007	$/MW-Day	$/MW in 2008	2008 Total
AECO	EMAAC	$197.67	$30,046	$148.80	$31,843	$61,889
AEP	RTO	$40.80	$6,202	$111.92	$23,951	$30,152
AP	RTO	$40.80	$6,202	$111.92	$23,951	$30,152
BGE	SWMAAC	$188.54	$28,658	$210.11	$44,964	$73,622
ComEd	RTO	$40.80	$6,202	$111.92	$23,951	$30,152
DAY	RTO	$40.80	$6,202	$111.92	$23,951	$30,152
Dominion	RTO	$40.80	$6,202	$111.92	$23,951	$30,152
DLCO	RTO	$40.80	$6,202	$111.92	$23,951	$30,152
DPL	EMAAC	$197.67	$30,046	$148.80	$31,843	$61,889
JCPL	EMAAC	$197.67	$30,046	$148.80	$31,843	$61,889
Met-Ed	RTO	$40.80	$6,202	$111.92	$23,951	$30,152
PECO	EMAAC	$197.67	$30,046	$148.80	$31,843	$61,889
PENELEC	RTO	$40.80	$6,202	$111.92	$23,951	$30,152
Pepco	SWMAAC	$188.54	$28,658	$210.11	$44,964	$73,622
PPL	RTO	$40.80	$6,202	$111.92	$23,951	$30,152
PSEG	EMAAC	$197.67	$30,046	$148.80	$31,843	$61,889
RECO	EMAAC	$197.67	$30,046	$148.80	$31,843	$61,889
PJM	N/A	$88.09	$13,390	$124.58	$26,660	$40,050

Table 3-4 shows zonal capacity revenue for the ten-year period 1999 to 2008.[11] Results for 1999 through 2006 reflect the load-weighted averages from the CCM construct. Results for 2007 combine the CCM values for the January through May period and the RPM Auction values for the June through December period.[12] Capacity revenue for 2008 reflects the first full year under the RPM construct, with five months of the first auction clearing price and seven months of the second auction clearing price.[13] These capacity revenues are adjusted for the yearly, systemwide forced outage rate.[14]

11 In tables with zonal net revenues, data for a transmission zone are displayed for all full calendar years following integration into PJM markets.

12 In Table 3-4, the 2007 column represents an average of all revenue associated with the sale of capacity by zone followed by a weighted-average of capacity revenue for the PJM footprint. The zonal results combine load-weighted averages from both daily and monthly CCM prices for January through May as well as the associated LDA-clearing price for the remaining seven months.

13 The 2007 total revenue associated with capacity for PJM in Table 3-4 similarly combines load-weighted CCM and RPM revenues. The RPM revenue for PJM in 2007 and 2008 is a load-weighted average based on all the LDA-clearing prices in Table 3-3 and the MW associated with each. The result is a load-weighted, average revenue associated with the sale of capacity per MW-year throughout the PJM footprint, not exclusively the RTO LDA.

14 The PJM capacity revenues presented in Table 3-4 differ slightly from those presented in Table 3-10, Table 3-12 and Table 3-14 as capacity revenues by technology type are adjusted for technology-specific outage rates.

Table 3-4 Capacity revenue by PJM zones (Dollars per MW-year): Calendar years 1999 to 2008

Zone	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Average
AECO	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$39,680	$57,323	$19,700
AEP	NA	NA	NA	NA	NA	NA	$2,089	$1,958	$8,551	$27,928	$10,131
AP	NA	NA	NA	NA	$7,633	$6,493	$2,089	$1,958	$8,551	$27,928	$9,109
BGE	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$37,868	$68,190	$20,605
ComEd	NA	NA	NA	NA	NA	NA	$3,607	$1,958	$8,551	$27,928	$10,511
DAY	NA	NA	NA	NA	NA	NA	$2,089	$1,958	$8,551	$27,928	$10,131
Dominion	NA	NA	NA	NA	NA	NA	NA	$1,958	$8,551	$27,928	$12,812
DLCO	NA	NA	NA	NA	NA	NA	$2,089	$1,958	$8,551	$27,928	$10,131
DPL	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$39,680	$57,323	$19,700
JCPL	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$39,680	$57,323	$19,700
Met-Ed	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$8,551	$27,928	$13,647
PECO	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$39,680	$57,323	$19,700
PENELEC	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$8,551	$27,928	$13,647
Pepco	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$37,868	$68,190	$20,605
PPL	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$8,551	$27,928	$13,647
PSEG	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$39,680	$57,323	$19,700
RECO	NA	NA	NA	NA	$5,946	$6,493	$2,089	$1,958	$39,680	$57,323	$18,915
PJM	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$29,966	$37,095	$16,706

Ancillary Service and Operating Reserve Net Revenue

In addition to Capacity and Energy Market revenues, generators can receive revenue from the sale of ancillary services, including those from the Synchronized Reserve and Regulation Markets as well as from black start and reactive services. Aggregate ancillary service revenues, displayed for the years 1999 through 2008 in Table 3-5, were $4,970 per installed MW-year in 2008.[15] While actual, generator-specific ancillary service revenues vary with generator technology, ancillary service revenues are expressed here in terms of a system average per installed MW. New entrant net revenue calculations, addressed later in this section, use more detailed, technology-specific ancillary service estimates.

15 The 2007 value in Table 3-5 is different than the value initially published in the *2007 State of the Market Report*. See <http://www.MonitoringAnalytics.com/reports/PJM_State_of_the_Market/2007/2007-som-volume2-errata.pdf>.

Table 3-5 System average ancillary service revenue: Calendar years 1999 to 2008

	Dollars per Installed MW-Year
1999	$3,444
2000	$4,509
2001	$3,831
2002	$3,500
2003	$3,986
2004	$3,667
2005	$5,135
2006	$3,926
2007	$4,284
2008	$4,970

Generators also receive operating reserve revenues from both the Day-Ahead and Real-Time Energy Markets. Operating reserve payments were about $2,000 per installed MW-year in 2007 and were about $2,100 per installed MW-year in 2008. These payments are designed, in part, to ensure that generators are paid enough to cover their offers, including startup and no-load costs, when scheduled by PJM so that they are not required to run at a loss.

New Entrant Net Revenues

In order to provide a more realistic estimate of the net revenues that would result from investment in new generation resources, a peak-hour, economic dispatch scenario was analyzed. In contrast to the perfect dispatch scenario, economic dispatch uses technology-specific operating constraints in the calculation of a new entrant's operations and potential net revenue in PJM markets. All technology-specific, zonal net revenue calculations included in the new entrant net revenue analysis in this section are based on the economic dispatch scenario.

Analysis of both the Real-Time and Day-Ahead Energy Market net revenues for a new entrant includes three power plant configurations: a natural gas-fired CT, a two-on-one, natural gas-fired CC and a conventional CP, single reheat steam generation plant. The CT plant consists of two GE Frame 7FA CTs, equipped with full inlet air mechanical refrigeration and selective catalytic reduction (SCR) for NOx reduction. The CC plant consists of two GE Frame 7FA CTs with evaporative cooling, two heat recovery steam generators (HRSG) one for each CT and a single steam turbine generator. The HRSG is equipped with duct burners, intermediate pressure steam reheat and selective catalytic reduction (SCR) for NOx reduction. The coal plant is a western Pennsylvania steam CP, equipped with lime injection for SO_2 reduction and low NOx burners in conjunction with over fire air for NOx control.

All net revenue calculations include the use of actual hourly local ambient air temperature[16] and river water cooling temperature[17] and the effect of each, as applicable, on plant heat rates[18] and generator output for each of the three plant configurations.[19] Plant heat rates were calculated for each hour to account for the efficiency changes and corresponding cost changes resulting from ambient air and river condition variations.[20] The effect of ambient air conditions and river water temperature on plant generation capability was calculated hourly. Available capacity is adjusted downward by the actual class average forced outage rate for each generator type in order to obtain the level of unforced capacity available for sale in PJM's Capacity Markets.

NO_x and SO_2 emission allowance costs are included in the hourly plant dispatch cost, where applicable. These costs are included in the PJM definition of marginal cost. NO_x and SO_2 emission allowance costs were obtained from actual historical daily spot cash prices.[21] NO_x emission allowance costs were included only during the annual NO_x attainment period from May 1 through September 30. SO_2 emission allowance costs were calculated for every hour of the year.

A forced outage rate for each class of plant was calculated from PJM data.[22] This class-specific outage rate was then incorporated into all revenue calculations. Additionally, each plant was given a continuous 15 day planned, annual outage in the fall season.

Variable operation and maintenance (VOM) expenses were estimated to be $6.47 per MWh for the CT plant, $2.80 per MWh for the CC plant and $3.00 per MWh for the CP plant. These estimates were provided by a consultant to the MMU and are based on quoted, third-party contract prices.[23] The VOM expenses for the CT and CC plants include accrual of anticipated, routine major overhaul expenses.[24] The delivered fuel cost for natural gas is from published commodity daily cash prices, with a basis adjustment for transportation costs.[25] Coal delivered cost was developed from the published prompt-month price, adjusted for rail transportation cost.[26] The average delivered fuel prices are shown in Table 3-6.

Real-time ancillary service revenues for the provision of synchronized reserve service for all three plant types are set to zero. GE Frame 7FA CTs are typically not configured to provide Tier 2 synchronized reserve in PJM. Steam units do provide Tier 1 synchronized reserve, but the 2008 Tier 1 revenues were minimal. Real-time ancillary service revenues for the provision of regulation service for both the CT and CC plant are also set to zero. Additionally, no black start service capability is assumed for the reference CT plant configuration in either costs or revenues. Real-time ancillary service revenues for the provision of regulation were calculated for the CP plant. The

16 Hourly ambient conditions supplied by Meteorlogix for multiple points in PJM RTO. PJM net revenue calculations include the average of all points in PJM RTO. Zonal net revenue calculations include zone specific ambient air temperatures,

17 Hourly river water temperatures are estimated using local, zone specific ambient air conditions. The relationship between ambient air and local river temperatures is developed using data from the Philadelphia International Airport and the Reedy Island Jetty Gauge station located on the Delaware River. River data obtained from U.S. Department of the Interior, U.S. Geological Survey <http://nwis.waterdata.usgs.gov/pa/nwis/qwdata?site_no=01482800>.

18 These heat rate changes were calculated by Pasteris Energy, Inc., a consultant to the MMU, utilizing GE Energy's GateCycle Power Plant and Simulation Software. Neither GE Energy nor GE has reviewed this report or the calculations and results of the work done by Pasteris Energy, Inc. for the MMU.

19 Pasteris Energy, Inc.

20 All heat rate calculations are expressed in Btu per net kWh. No-load costs are included in the heat rate and subsequently the dispatch price since each unit type is dispatched at full load for every economic hour, but is off for every uneconomic hour. Therefore, there is a single offer point and no offer curve.

21 NO_x and SO_2 emission daily prompt prices obtained from Evolution Markets, Inc.

22 Outage figures obtained from the PJM eGADS database.

23 Pasteris Energy, Inc.

24 Routine combustor inspection, hot gas path and major inspection costs collected through the VOM adder. This figure was established by Pasteris Energy, Inc. and compares favorably with actual operation and maintenance costs from similar PJM generating units.

25 Gas daily cash prices obtained from Platts.

26 Coal prompt prices obtained from Platts.

regulation offer price was the sum of the calculated hourly cost to supply regulation service plus an adder of $7.50, per PJM market rules.[27] This offer price was compared to the hourly clearing price in the PJM Regulation Market. The clearing price includes both the offer price and the lost opportunity cost of the marginal unit in each hour. If the reference CP could provide regulation at a total cost, including the CP opportunity cost, that is less than the regulation-clearing price, the regulation service net revenue equals the market price of regulation minus the cost of CP regulation.

Generators receive revenues for the provision of reactive services based on cost-of-service filings with the United States Federal Energy Regulatory Commission (FERC). The actual reactive service payments filed with and approved by the FERC for each generator class were used to determine the reactive revenues. Reactive service revenues are based on the weighted-average reactive service rate per MW-year calculated from the data in the FERC filings. In 2008, for CTs, the calculated rate is $2,398 per installed MW-year; for CCs, the calculated rate is $3,198 per installed MW-year and for CPs, the calculated rate is $1,783 per installed MW-year.[28]

Table 3-6 Average delivered fuel price in PJM (Dollars per MBtu): Calendar years 1999 to 2008

	Natural Gas	Low Sulfur Coal
1999	$2.62	$1.62
2000	$5.18	$1.39
2001	$4.52	$2.14
2002	$3.81	$1.54
2003	$6.45	$1.76
2004	$6.65	$2.74
2005	$9.73	$2.88
2006	$7.40	$2.68
2007	$7.87	$2.53
2008	$9.95	$4.60

Zonal Real-Time Energy Market net revenue under a peak-hour, economic dispatch scenario for 1999 to 2008 is shown in Table 3-7, Table 3-8 and Table 3-9 for new entrant CT, CC and CP facilities, respectively. The difference in net revenue among zones is a direct result of the locational variation in hourly LMP and delivered fuel costs.[29] The difference in net revenue among the generation technologies is a direct result of the variation in marginal cost associated with each.

27 The adder was not adjusted to reflect the modifications to the regulation market rules that were effective on December 1, 2008.

28 The CT plant reactive revenues are based on 43 recent filings with the FERC for CT reactive costs. The CC plant revenues are based on 27 recent filings with the FERC for CC reactive costs, and the CP plant revenues are based on 18 recent filings with the FERC for CP reactive costs. These figures have been updated from those reported in the *2007 State of the Market Report* to include new generation filings.

29 Zonal net revenues for 2008 reflect the estimated average delivered fuel costs associated with each zone and increased locational fuel cost detail compared to 2007. As a result, changes from 2007 to 2008 zonal energy net revenue may reflect changes in estimated fuel costs in addition to changes in fuel price fundamentals.

Table 3-7 PJM Real-Time Energy Market net revenue for a new entrant gas-fired CT under economic dispatch (Dollars per installed MW-year): Net revenue for calendar years 1999 to 2008

Zone	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Average
AECO	$56,278	$12,077	$40,825	$19,449	$5,274	$6,765	$18,309	$23,165	$41,985	$65,046	$28,917
AEP	NA	NA	NA	NA	NA	NA	$641	$4,638	$5,959	$4,458	$3,924
AP	NA	NA	NA	NA	$1,069	$864	$5,190	$10,695	$17,726	$17,701	$8,874
BGE	$54,770	$7,193	$23,048	$20,049	$4,196	$2,899	$22,293	$31,725	$56,613	$47,525	$27,031
ComEd	NA	NA	NA	NA	NA	NA	$1,747	$7,131	$9,271	$4,886	$5,759
DAY	NA	NA	NA	NA	NA	NA	$793	$4,342	$5,776	$4,672	$3,896
Dominion	NA	NA	NA	NA	NA	NA	NA	$26,830	$43,653	$43,465	$37,983
DLCO	NA	NA	NA	NA	NA	NA	$665	$5,408	$9,805	$7,746	$5,906
DPL	$57,625	$12,712	$49,833	$22,430	$5,587	$2,881	$14,259	$17,265	$34,151	$35,422	$25,217
JCPL	$55,947	$9,803	$37,473	$13,933	$2,982	$14,472	$16,933	$15,932	$37,836	$35,166	$24,048
Met-Ed	$54,998	$8,068	$30,697	$17,372	$3,603	$2,271	$15,174	$17,503	$36,393	$25,498	$21,158
PECO	$56,510	$11,760	$37,989	$14,761	$4,836	$1,600	$16,114	$15,600	$28,560	$27,081	$21,481
PENELEC	$54,997	$7,360	$18,137	$12,117	$1,731	$1,264	$3,117	$6,585	$10,957	$5,953	$12,222
Pepco	$54,556	$7,022	$18,108	$22,024	$4,610	$3,915	$25,840	$37,801	$58,816	$54,838	$28,753
PPL	$55,305	$7,753	$26,748	$12,589	$2,265	$1,120	$12,403	$13,612	$25,472	$21,531	$17,880
PSEG	$56,271	$10,171	$36,818	$13,499	$4,555	$13,163	$16,881	$15,980	$32,405	$28,809	$22,855
RECO	NA	NA	NA	NA	$4,213	$3,749	$12,971	$13,606	$32,295	$23,966	$15,133
PJM	$55,612	$8,498	$30,254	$14,496	$2,763	$919	$6,141	$10,996	$17,933	$12,442	$16,005

Table 3-8 PJM Real-Time Energy Market net revenue for a new entrant gas-fired CC under economic dispatch (Dollars per installed MW-year): Net revenue for calendar years 1999 to 2008

Zone	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Average
AECO	$80,930	$29,354	$68,323	$46,203	$35,658	$52,625	$77,223	$78,489	$107,344	$154,085	$73,023
AEP	NA	NA	NA	NA	NA	NA	$12,533	$21,695	$29,990	$29,194	$23,353
AP	NA	NA	NA	NA	$19,036	$20,163	$35,748	$41,735	$65,495	$68,874	$41,842
BGE	$78,672	$21,290	$42,575	$45,040	$29,165	$33,539	$75,682	$83,645	$131,526	$133,647	$67,478
ComEd	NA	NA	NA	NA	NA	NA	$21,779	$30,731	$42,289	$30,764	$31,391
DAY	NA	NA	NA	NA	NA	NA	$11,872	$19,706	$30,024	$29,754	$22,839
Dominion	NA	NA	NA	NA	NA	NA	NA	$78,267	$110,994	$123,330	$104,197
DLCO	NA	NA	NA	NA	NA	NA	$10,781	$18,897	$32,552	$28,813	$22,761
DPL	$83,748	$34,057	$79,508	$49,163	$33,913	$39,091	$61,167	$61,072	$99,001	$117,134	$65,785
JCPL	$80,716	$25,825	$61,175	$36,979	$26,955	$63,200	$67,269	$56,368	$108,661	$126,738	$65,389
Met-Ed	$79,528	$22,995	$53,339	$41,469	$27,374	$31,279	$57,351	$59,317	$102,856	$99,239	$57,475
PECO	$81,255	$28,010	$61,526	$38,389	$31,489	$34,570	$61,212	$57,349	$89,797	$102,673	$58,627
PENELEC	$79,720	$23,011	$39,473	$42,071	$22,929	$21,460	$26,611	$30,472	$51,289	$44,971	$38,201
Pepco	$78,343	$20,865	$36,952	$46,354	$29,914	$36,202	$82,427	$91,120	$133,305	$144,783	$70,027
PPL	$79,926	$22,122	$48,045	$34,624	$25,278	$24,688	$51,686	$52,858	$85,950	$92,238	$51,742
PSEG	$82,577	$28,650	$62,468	$37,769	$34,549	$63,575	$78,181	$66,446	$105,692	$119,564	$67,947
RECO	NA	NA	NA	NA	$33,679	$44,473	$64,071	$61,510	$103,158	$108,670	$69,260
PJM	$80,546	$24,794	$54,206	$38,625	$27,155	$27,389	$35,608	$44,692	$66,616	$62,039	$46,167

Table 3-9 PJM Real-Time Energy Market net revenue for a new entrant CP under economic dispatch (Dollars per installed MW-year): Net revenue for calendar years 1999 to 2008

Zone	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Average
AECO	$92,532	$113,438	$108,787	$105,966	$168,971	$167,610	$301,137	$228,664	$303,350	$337,789	$192,824
AEP	NA	NA	NA	NA	NA	NA	$142,931	$122,131	$158,510	$152,316	$143,972
AP	NA	NA	NA	NA	$140,178	$114,188	$225,283	$173,387	$243,442	$257,660	$192,356
BGE	$90,218	$99,688	$81,733	$103,811	$163,240	$138,798	$297,298	$243,615	$339,865	$309,846	$186,811
ComEd	NA	NA	NA	NA	NA	NA	$136,055	$117,135	$152,722	$203,863	$152,444
DAY	NA	NA	NA	NA	NA	NA	$132,250	$114,159	$157,981	$130,757	$133,787
Dominion	NA	NA	NA	NA	NA	NA	NA	$235,662	$316,223	$282,137	$278,007
DLCO	NA	NA	NA	NA	NA	NA	$119,344	$102,923	$145,539	$138,614	$126,605
DPL	$96,172	$124,924	$129,746	$109,500	$168,958	$150,777	$280,855	$208,044	$296,729	$320,362	$188,607
JCPL	$92,252	$105,657	$99,367	$94,661	$155,564	$177,105	$284,427	$198,595	$310,102	$315,991	$183,372
Met-Ed	$91,053	$102,018	$92,371	$99,157	$157,131	$135,061	$269,900	$205,508	$299,833	$282,260	$173,429
PECO	$92,923	$112,043	$101,558	$96,113	$163,941	$144,385	$279,306	$203,152	$284,280	$290,745	$176,845
PENELEC	$91,889	$109,408	$84,093	$107,445	$154,295	$114,543	$210,236	$156,723	$222,720	$239,391	$149,074
Pepco	$89,875	$99,351	$75,464	$105,125	$164,995	$142,377	$307,867	$254,964	$344,407	$328,211	$191,264
PPL	$91,447	$100,853	$86,582	$89,955	$152,675	$127,012	$260,567	$196,349	$279,724	$286,355	$167,152
PSEG	$95,195	$121,405	$108,158	$96,439	$174,161	$180,518	$309,870	$219,768	$310,978	$248,728	$186,522
RECO	NA	NA	NA	NA	$176,678	$159,188	$292,449	$213,850	$304,891	$259,424	$234,413
PJM	$92,935	$108,624	$95,361	$96,828	$159,912	$124,497	$222,911	$177,852	$244,419	$179,457	$150,280

New Entrant Combustion Turbine

In the peak-hour, economic dispatch analysis, Real-Time Energy Market net revenue was calculated for a CT plant dispatched by PJM operations. For this dispatch scenario, it was assumed that the CT plant could be dispatched by PJM operations in four distinct blocks of four hours of continuous output for each block from the peak-hour period beginning with the hour ending 0800 EPT through to the hour ending 2300 EPT for any block when the real-time, average LMP was greater than, or equal to, the cost to generate, including the cost for a complete startup and shutdown cycle[30] for at least two hours during each four-hour block.[31] The blocks were dispatched independently, and, if there were not at least two economic hours in any given block, then the CT was not dispatched. The startup costs were used in determining the economic hours in each block, but once the CT was dispatched on a particular day, startup costs were not used to evaluate whether to continue to run the unit in the next consecutive four-hour block. The calculations account for operating reserve

30 Startup and shutdown fuel burns and emission rates were obtained from design data for a new entry plant. Gas daily cash prices were obtained from Platts fuel prices. Emissions allowance costs were included in startup costs where applicable. Per PJM "Manual M-15: Cost Development Guidelines," Revision 7 (August 3, 2006), startup and shutdown station power consumption costs were obtained from the station service rates published quarterly by PJM and netted against the MW produced during startup at the preceding applicable hourly LMP. No-load costs are included in the heat rate.

31 The first block represents the four-hour period starting at hour ending 0800 EPT until hour ending 1100 EPT. The second block represents the four-hour period starting at hour ending 1200 EPT until hour ending 1500 EPT. The third block represents the four-hour period starting at hour ending 1600 EPT until hour ending 1900 EPT, and the fourth block represents the four-hour period starting at hour ending 2000 EPT until the hour ending 2300 EPT.

credits based on PJM rules, as applicable, since the assumed operation is under the direction of PJM operations.[32]

Net revenues for the new entrant CT under peak-hour, economic dispatch are shown in Table 3-10 for the years 1999 through 2008. This table shows the contribution of each market individually to the new entrant CT's total net revenue. The increase in capacity revenue is a result of a full year of RPM revenue.

Table 3-10 Real-time PJM-wide net revenue for a CT under peak-hour, economic dispatch by market (Dollars per installed MW-year): Calendar years 1999 to 2008

	Energy	Capacity	Synchronized	Regulation	Reactive	Total
1999	$55,612	$16,677	$0	$0	$2,248	$74,537
2000	$8,498	$20,200	$0	$0	$2,248	$30,946
2001	$30,254	$30,960	$0	$0	$2,248	$63,462
2002	$14,496	$11,516	$0	$0	$2,248	$28,260
2003	$2,763	$5,554	$0	$0	$2,248	$10,566
2004	$919	$5,376	$0	$0	$2,248	$8,543
2005	$6,141	$2,048	$0	$0	$2,248	$10,437
2006	$10,996	$1,758	$0	$0	$2,194	$14,948
2007	$17,933	$28,442	$0	$0	$2,154	$48,529
2008	$12,442	$35,691	$0	$0	$2,398	$50,532

Table 3-11 shows the total net revenue (the Total column in Table 3-10) for the new entrant CT in each zone.[33] For the ten-year period, the average total net revenue under the peak-hour, economic dispatch scenario was $34,076 per installed MW-year.

32 The calculation of operating reserve payments does not reflect changes to operating reserves rules effective December 1, 2008.
33 New entrant CT zonal net revenue for 2008 reflects the estimated zonal, daily delivered price of natural gas.

Table 3-11 Real-time zonal combined net revenue from all markets for a CT under peak-hour, economic dispatch (Dollars per installed MW-year): Calendar years 1999 to 2008

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Average
AECO	$75,203	$34,525	$74,033	$33,213	$13,077	$14,389	$22,605	$27,117	$81,801	$122,598	$49,856
AEP	NA	NA	NA	NA	NA	NA	$4,936	$8,590	$16,230	$33,727	$15,871
AP	NA	NA	NA	NA	$10,800	$8,487	$9,485	$14,647	$27,996	$46,970	$19,731
BGE	$73,695	$29,641	$56,256	$33,813	$11,998	$10,522	$26,589	$35,678	$94,710	$115,532	$48,843
ComEd	NA	NA	NA	NA	NA	NA	$7,602	$11,083	$19,542	$34,155	$18,096
DAY	NA	NA	NA	NA	NA	NA	$5,089	$8,294	$16,046	$33,941	$15,843
Dominion	NA	NA	NA	NA	NA	NA	NA	$30,782	$53,923	$72,734	$52,480
DLCO	NA	NA	NA	NA	NA	NA	$4,960	$9,360	$20,075	$37,015	$17,853
DPL	$76,550	$35,160	$83,041	$36,193	$13,389	$10,505	$18,554	$21,217	$73,967	$92,974	$46,155
JCPL	$74,871	$32,251	$70,681	$27,697	$10,784	$22,096	$21,229	$19,884	$77,652	$92,718	$44,986
Met-Ed	$73,923	$30,516	$63,905	$31,136	$11,406	$9,894	$19,469	$21,455	$46,663	$54,767	$36,313
PECO	$75,434	$34,208	$71,197	$28,525	$12,638	$9,224	$20,409	$19,552	$68,376	$84,633	$42,420
PENELEC	$73,921	$29,808	$51,345	$25,881	$9,533	$8,887	$7,413	$10,537	$21,227	$35,222	$27,377
Pepco	$73,480	$29,470	$51,316	$35,788	$12,413	$11,539	$30,135	$41,753	$96,912	$122,845	$50,565
PPL	$74,229	$30,201	$59,956	$26,353	$10,068	$8,744	$16,699	$17,564	$35,743	$50,800	$33,036
PSEG	$75,196	$32,618	$70,026	$27,263	$12,357	$20,786	$21,177	$19,933	$72,221	$86,361	$43,794
RECO	NA	NA	NA	NA	$12,016	$11,373	$17,266	$17,558	$72,112	$81,518	$35,307
PJM	$74,537	$30,946	$63,462	$28,260	$10,566	$8,543	$10,437	$14,948	$48,530	$50,532	$34,076

New Entrant Combined Cycle

Under peak-hour, economic dispatch, Energy Market net revenues were calculated for a CC plant dispatched by PJM operations for continuous output from the peak-hour period beginning with the hour ending 0800 EPT and continuing to the hour ending 2300 EPT for any day when the PJM real-time, average LMP was greater than, or equal to, the cost to generate, including the cost for a complete startup and shutdown cycle for at least eight hours during that time period.[34] If there were not eight economic hours in any given day, then the CC was not dispatched. For every hour the plant is dispatched, the applicable LMP is compared to the incremental costs of duct-firing, including fuel and, if applicable, emissions allowance credits.[35] If LMP is greater than or equal to the incremental costs of duct-firing for any hour the plant is operating, the duct burner is dispatched. The calculations account for operating reserve payments based on PJM rules, when applicable, since the assumed operation is under the direction of PJM operations. This dispatch scenario

34 Startup and shutdown fuel burns and emission rates were obtained from design data for a new entry plant. Gas daily cash prices were obtained from Platts fuel prices. Emissions allowance costs were included in startup costs where applicable. Per PJM "Manual M-15: Cost Development Guidelines," Revision 7 (August 3, 2006), startup and shutdown station power consumption costs were obtained from the station service rates published quarterly by PJM settlements and netted against the MW produced during startup at the preceding applicable hourly LMP. No-load costs are included in the heat rate.

35 Duct-firing dispatch rate is developed using same methodology described for unfired dispatch rate, with temperature adjustments to duct-fired heat rate and output provided by Pasteris Energy, Inc.

uses the same variable operation and maintenance cost, outage, fuel cost, emission and plant performance assumptions reflected in the Table 3-8 results.

Net revenues for the new entrant CC under peak-hour, economic dispatch are shown in Table 3-12 for the years 1999 through 2008. This table shows the contribution of each market individually to the new entrant CC's total net revenue. The increase in capacity revenue is a result of a full year of RPM revenue.

Table 3-12 Real-time PJM-wide net revenue for a CC under peak-hour, economic dispatch by market (Dollars per installed MW-year): Calendar years 1999 to 2008

	Energy	Capacity	Synchronized	Regulation	Reactive	Total
1999	$80,546	$16,999	$0	$0	$3,155	$100,700
2000	$24,794	$19,643	$0	$0	$3,155	$47,592
2001	$54,206	$29,309	$0	$0	$3,155	$86,670
2002	$38,625	$10,492	$0	$0	$3,155	$52,272
2003	$27,155	$5,281	$0	$0	$3,155	$35,591
2004	$27,389	$5,241	$0	$0	$3,155	$35,785
2005	$35,608	$2,054	$0	$0	$3,155	$40,817
2006	$44,692	$1,743	$0	$0	$3,094	$49,529
2007	$66,616	$31,098	$0	$0	$3,094	$100,809
2008	$62,039	$38,691	$0	$0	$3,198	$103,928

Table 3-13 shows the total net revenue (the Total column in Table 3-12) for the new entrant CC in each zone. For the ten-year period, the average total net revenue under the peak-hour, economic dispatch scenario was $65,369 per installed MW-year.

Table 3-13 Real-time zonal combined net revenue from all markets for a CC under peak-hour, economic dispatch (Dollars per installed MW-year): Calendar years 1999 to 2008

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Average
AECO	$101,084	$52,152	$100,786	$59,850	$44,094	$61,021	$82,432	$83,326	$151,617	$217,072	$95,343
AEP	NA	NA	NA	NA	NA	NA	$17,742	$26,533	$41,958	$61,521	$36,939
AP	NA	NA	NA	NA	$29,766	$28,560	$40,957	$46,572	$77,463	$101,201	$54,087
BGE	$98,827	$44,088	$75,039	$58,688	$37,601	$41,935	$80,891	$88,482	$173,918	$207,969	$90,744
ComEd	NA	NA	NA	NA	NA	NA	$28,702	$35,568	$54,257	$63,092	$45,405
DAY	NA	NA	NA	NA	NA	NA	$17,081	$24,543	$41,992	$62,081	$36,424
Dominion	NA	NA	NA	NA	NA	NA	NA	$83,104	$122,963	$155,658	$120,575
DLCO	NA	NA	NA	NA	NA	NA	$15,990	$23,734	$44,520	$61,141	$36,346
DPL	$103,903	$56,855	$111,972	$62,811	$42,349	$47,487	$66,376	$65,909	$143,274	$180,121	$88,106
JCPL	$100,871	$48,623	$93,639	$50,626	$35,391	$71,596	$72,478	$61,205	$152,934	$189,725	$87,709
Met-Ed	$99,682	$45,793	$85,803	$55,117	$35,810	$39,675	$62,560	$64,155	$114,824	$131,566	$73,499
PECO	$101,410	$50,808	$93,990	$52,036	$39,925	$42,967	$66,421	$62,187	$134,069	$165,660	$80,947
PENELEC	$99,875	$45,809	$71,937	$55,718	$31,365	$29,856	$31,820	$35,309	$63,257	$77,299	$54,225
Pepco	$98,497	$43,663	$69,416	$60,001	$38,350	$44,598	$87,636	$95,957	$175,698	$219,105	$93,292
PPL	$100,081	$44,920	$80,509	$48,272	$33,714	$33,084	$56,895	$57,695	$97,918	$124,566	$67,765
PSEG	$102,731	$51,448	$94,932	$51,416	$42,985	$71,972	$83,390	$71,284	$149,965	$182,551	$90,267
RECO	NA	NA	NA	NA	$42,115	$52,870	$69,280	$66,348	$147,431	$171,658	$91,617
PJM	$100,700	$47,592	$86,670	$52,272	$35,591	$35,785	$40,817	$49,529	$100,809	$103,928	$65,369

New Entrant Coal Plant

The new entrant CP Real-Time Energy Market net revenues were calculated assuming that the plant had a 24-hour minimum run time and was dispatched by PJM operations for all available plant hours, both reasonable assumptions for a large CP. The calculations account for operating reserve payments based on PJM rules, when applicable, since the assumed operation is under the direction of PJM operations.

Net revenues for the new entrant CP under peak-hour, economic dispatch are shown in Table 3-14 for the years 1999 through 2008. This table shows the contribution of each market individually to the new entrant CP's total net revenue. The increase in capacity revenue is a result of the implementation of RPM. Regulation revenue is calculated for any hours in which the new entrant CP's regulation offer is below the regulation-clearing price.

Table 3-14 Real-time PJM-wide net revenue for a CP under peak-hour, economic dispatch by market (Dollars per installed MW-year): Calendar years 1999 to 2008

	Energy	Capacity	Synchronized	Regulation	Reactive	Total
1999	$92,935	$17,798	$0	$5,596	$1,692	$118,022
2000	$108,624	$20,755	$0	$3,492	$1,692	$134,564
2001	$95,361	$30,862	$0	$1,356	$1,692	$129,271
2002	$96,828	$11,493	$0	$2,118	$1,692	$112,131
2003	$159,912	$5,688	$0	$2,218	$1,692	$169,509
2004	$124,497	$5,537	$0	$1,399	$1,692	$133,124
2005	$222,911	$2,100	$0	$1,727	$1,692	$228,430
2006	$177,852	$1,810	$0	$1,107	$1,692	$182,461
2007	$244,419	$29,343	$0	$1,172	$2,350	$277,284
2008	$179,457	$36,107	$0	$796	$1,783	$218,144

Table 3-15 shows the total net revenue (the Total column 7 in Table 3-14) for the new entrant CP in each zone.[36] For the ten-year period, the average total net revenue under the economic dispatch scenario was $170,294 per installed MW-year.

Table 3-15 Real-time zonal combined net revenue from all markets for a CP under peak-hour, economic dispatch (Dollars per installed MW-year): Calendar years 1999 to 2008

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Average
AECO	$118,254	$137,752	$143,257	$121,785	$179,117	$176,827	$306,995	$233,787	$345,739	$396,564	$216,008
AEP	NA	NA	NA	NA	NA	NA	$150,176	$127,588	$170,532	$182,201	$157,624
AP	NA	NA	NA	NA	$152,458	$123,620	$231,963	$178,701	$255,474	$288,025	$205,040
BGE	$115,926	$124,106	$116,306	$119,714	$173,476	$148,097	$303,218	$248,764	$380,425	$379,157	$210,919
ComEd	NA	NA	NA	NA	NA	NA	$144,924	$122,647	$164,740	$234,487	$166,700
DAY	NA	NA	NA	NA	NA	NA	$139,572	$119,691	$169,421	$160,462	$147,287
Dominion	NA	NA	NA	NA	NA	NA	NA	$240,828	$328,069	$312,361	$293,753
DLCO	NA	NA	NA	NA	NA	NA	$126,378	$108,418	$157,544	$168,837	$140,294
DPL	$121,871	$149,240	$164,219	$125,338	$179,145	$160,037	$287,243	$213,261	$339,158	$379,118	$211,863
JCPL	$117,958	$129,968	$133,853	$110,647	$165,730	$186,317	$290,747	$203,776	$352,520	$374,645	$206,616
Met-Ed	$116,776	$126,376	$126,885	$115,061	$167,368	$144,386	$276,296	$210,720	$311,760	$312,370	$190,800
PECO	$118,636	$136,379	$136,046	$112,096	$174,147	$153,658	$285,681	$208,382	$326,717	$349,522	$200,126
PENELEC	$117,603	$133,724	$118,787	$123,416	$164,692	$123,984	$217,133	$162,124	$234,790	$269,748	$166,600
Pepco	$115,585	$123,766	$110,090	$121,020	$175,224	$151,666	$314,137	$260,110	$384,940	$397,620	$215,416
PPL	$117,166	$125,227	$121,146	$105,991	$162,900	$136,365	$267,023	$201,584	$291,701	$316,263	$184,537
PSEG	$120,910	$145,675	$142,694	$112,410	$184,332	$189,717	$316,131	$224,904	$353,386	$307,268	$209,743
RECO	NA	NA	NA	NA	$186,860	$168,414	$298,796	$219,016	$347,309	$318,225	$256,437
PJM	$118,022	$134,564	$129,271	$112,131	$169,509	$133,124	$228,430	$182,461	$277,284	$218,144	$170,294

36 New Entrant CP zonal net revenue for 2008 incorporates the zone specific, delivered price of coal.

New Entrant Day-Ahead Net Revenues

In order to develop a comprehensive net revenue analysis, Day-Ahead Energy Market net revenues were calculated for the CT, CC and CP technologies for the peak-hour, economic dispatch scenario used for the Real-Time Energy Market analysis.The results for the Day-Ahead Energy Market for each class are presented in Table 3-16, Table 3-17 and Table 3-18, respectively. [37]

Table 3-16 PJM Day-Ahead Energy Market net revenue for a new entrant gas-fired CT under economic dispatch (Dollars per installed MW-year): Calendar years 2000 to 2008

	2000	2001	2002	2003	2004	2005	2006	2007	2008	Average
AECO	$12,077	$29,022	$18,894	$2,634	$1,360	$11,975	$13,446	$20,649	$26,001	$15,118
AEP	NA	NA	NA	NA	NA	$563	$1,218	$2,267	$1,827	$1,469
AP	NA	NA	NA	$595	$0	$3,959	$7,326	$7,244	$6,719	$4,307
BGE	$7,193	$14,772	$14,087	$1,779	$42	$9,857	$13,886	$20,904	$27,271	$12,199
ComEd	NA	NA	NA	NA	NA	$374	$1,709	$4,392	$1,984	$2,115
DAY	NA	NA	NA	NA	NA	$477	$1,104	$2,003	$1,628	$1,303
Dominion	NA	NA	NA	NA	NA	NA	$10,991	$15,078	$22,582	$16,217
DLCO	NA	NA	NA	NA	NA	$308	$854	$1,818	$1,428	$1,102
DPL	$12,712	$35,962	$21,844	$2,419	$95	$7,869	$9,733	$12,438	$19,152	$13,580
JCPL	$9,803	$24,565	$16,658	$1,531	$489	$7,104	$8,263	$16,080	$14,163	$10,962
Met-Ed	$8,068	$19,353	$17,218	$1,273	$50	$8,737	$12,771	$14,559	$12,492	$10,502
PECO	$11,760	$26,271	$17,522	$2,089	$0	$10,129	$8,598	$11,330	$12,688	$11,154
PENELEC	$7,360	$16,870	$15,415	$537	$0	$1,477	$3,461	$3,736	$4,535	$5,932
Pepco	$7,022	$14,469	$13,780	$2,143	$0	$12,988	$18,258	$23,028	$32,677	$13,818
PPL	$7,753	$18,174	$15,151	$993	$0	$7,052	$8,259	$9,586	$10,351	$8,591
PSEG	$10,171	$25,298	$16,750	$258	$7,332	$7,332	$8,127	$12,718	$13,686	$11,297
RECO	NA	NA	NA	$1,346	$11	$5,925	$7,143	$11,711	$11,445	$6,264
PJM	$7,418	$20,390	$13,921	$1,282	$1	$2,996	$5,229	$6,751	$6,623	$7,179

37 The Day-Ahead Energy Market net revenues were calculated utilizing the same fuel, weather and unit operational assumptions as were used for the Real-Time Energy Market net revenue calculations.

Table 3-17 PJM Day-Ahead Energy Market net revenue for a new entrant gas-fired CC under economic dispatch (Dollars per installed MW-year): Calendar years 2000 to 2008

	2000	2001	2002	2003	2004	2005	2006	2007	2008	Average
AECO	$29,354	$63,679	$45,357	$31,788	$43,308	$74,855	$62,589	$83,745	$115,974	$61,183
AEP	NA	NA	NA	NA	NA	$10,462	$12,393	$19,516	$20,140	$15,628
AP	NA	NA	NA	$14,992	$14,077	$29,993	$30,144	$44,880	$50,885	$30,829
BGE	$21,290	$37,791	$34,829	$23,003	$23,810	$60,143	$64,078	$94,045	$118,704	$53,077
ComEd	NA	NA	NA	NA	NA	$9,888	$12,746	$35,333	$24,163	$20,533
DAY	NA	NA	NA	NA	NA	$8,451	$9,671	$19,014	$19,147	$14,071
Dominion	NA	NA	NA	NA	NA	NA	$57,718	$80,321	$101,261	$79,767
DLCO	NA	NA	NA	NA	NA	$7,709	$8,390	$17,819	$15,605	$12,381
DPL	$34,057	$73,455	$48,709	$28,595	$28,534	$59,804	$49,939	$74,526	$101,261	$55,431
JCPL	$25,825	$51,367	$39,102	$23,929	$48,514	$56,951	$42,774	$85,349	$112,307	$54,013
Met-Ed	$22,995	$44,572	$38,810	$22,806	$22,786	$52,522	$50,581	$75,423	$84,379	$46,097
PECO	$28,010	$55,775	$40,411	$27,252	$26,450	$59,822	$47,607	$70,234	$85,673	$49,026
PENELEC	$23,011	$43,234	$47,776	$17,460	$13,209	$23,711	$22,590	$35,002	$39,701	$29,522
Pepco	$20,865	$37,135	$34,523	$24,379	$26,052	$67,659	$71,755	$99,380	$133,227	$57,219
PPL	$22,122	$42,383	$35,750	$19,862	$17,037	$48,895	$43,246	$64,603	$77,511	$41,268
PSEG	$28,650	$57,168	$41,945	$27,192	$47,450	$65,167	$51,543	$87,724	$106,457	$57,033
RECO	NA	NA	NA	$25,148	$31,204	$54,167	$50,064	$85,050	$96,618	$57,042
PJM	$26,132	$48,253	$35,993	$21,865	$18,193	$28,413	$31,670	$44,434	$47,342	$33,588

Table 3-18 PJM Day-Ahead Energy Market net revenue for a new entrant CP under economic dispatch (Dollars per installed MW-year): Calendar years 2000 to 2008

	2000	2001	2002	2003	2004	2005	2006	2007	2008	Average
AECO	$113,438	$111,272	$108,715	$174,964	$156,185	$302,113	$215,274	$252,783	$323,135	$195,320
AEP	NA	NA	NA	NA	NA	$140,898	$111,399	$150,551	$149,397	$138,061
AP	NA	NA	NA	$145,314	$108,867	$219,168	$158,105	$223,836	$250,837	$184,355
BGE	$99,688	$83,030	$94,034	$161,419	$127,630	$284,669	$223,199	$304,373	$312,579	$187,847
ComEd	NA	NA	NA	NA	NA	$133,407	$108,663	$149,353	$210,403	$150,457
DAY	NA	NA	NA	NA	NA	$126,886	$98,084	$148,879	$123,738	$124,397
Dominion	NA	NA	NA	NA	NA	NA	$215,727	$289,976	$277,629	$261,111
DLCO	NA	NA	NA	NA	NA	$121,687	$92,737	$137,774	$139,537	$122,934
DPL	$124,924	$128,020	$111,746	$172,871	$141,541	$286,686	$201,807	$278,619	$324,485	$196,744
JCPL	$105,657	$94,134	$99,105	$164,028	$161,584	$278,746	$188,852	$289,222	$320,484	$189,090
Met-Ed	$102,018	$88,922	$99,331	$161,077	$127,001	$269,696	$199,865	$275,949	$286,549	$178,934
PECO	$112,043	$102,119	$101,674	$169,018	$137,889	$284,530	$198,441	$272,984	$297,666	$186,263
PENELEC	$109,408	$89,643	$118,915	$157,282	$108,203	$207,894	$147,998	$208,246	$251,168	$155,417
Pepco	$99,351	$82,420	$93,756	$163,851	$130,908	$295,462	$233,288	$313,215	$333,200	$193,939
PPL	$100,853	$86,022	$93,528	$156,929	$120,447	$263,597	$190,672	$263,141	$291,459	$174,072
PSEG	$121,405	$108,221	$106,049	$173,952	$162,402	$295,693	$207,951	$294,953	$250,151	$191,197
RECO	NA	NA	NA	$172,622	$143,445	$279,769	$207,438	$291,031	$315,939	$235,041
PJM	$116,784	$95,119	$97,493	$162,285	$113,892	$220,824	$167,282	$221,757	$174,191	$152,181

For the nine-year period, the average PJM Day-Ahead Energy Market net revenue under the peak-hour, economic dispatch scenario for the CT plant was $7,179 per installed MW-year. For the CC plant, the nine-year average Day-Ahead Energy Market net revenue under the peak-hour, economic dispatch scenario was $33,588 per installed MW-year. For the CP plant, the eight-year average Day-Ahead Energy Market net revenue under the peak-hour, economic dispatch scenario was $152,181 per installed MW-year.

The energy net revenues for both the Real-Time and Day-Ahead Energy Markets are shown in Table 3-19, Table 3-20 and Table 3-21 for the CT, CC and CP plants, respectively.

On average, the Real-Time Energy Market net revenue was 38 percent higher than the Day-Ahead Market net revenue for the CT plant, 21 percent higher for the CC plant and 3 percent higher for the CP.[38]

Table 3-19 Real-Time and Day-Ahead Energy Market net revenues for a CT under economic dispatch (Dollars per installed MW-year): Calendar years 2000 to 2008

	Real-Time Economic	Day-Ahead Economic	Actual Difference	Percent Difference
2000	$8,498	$7,418	$1,080	13%
2001	$30,254	$20,390	$9,864	33%
2002	$14,496	$13,921	$575	4%
2003	$2,763	$1,282	$1,481	54%
2004	$919	$1	$918	100%
2005	$6,141	$2,996	$3,145	51%
2006	$10,996	$5,229	$5,767	52%
2007	$17,933	$6,751	$11,183	62%
2008	$12,442	$6,623	$5,819	47%
Average	$11,605	$7,179	$4,426	38%

Table 3-20 Real-Time and Day-Ahead Energy Market net revenues for a CC under economic dispatch scenario (Dollars per installed MW-year): Calendar years 2000 to 2008

	Real-Time Economic	Day-Ahead Economic	Actual Difference	Percent Difference
2000	$24,794	$26,132	($1,338)	(5%)
2001	$54,206	$48,253	$5,953	11%
2002	$38,625	$35,993	$2,631	7%
2003	$27,155	$21,865	$5,290	19%
2004	$27,389	$18,193	$9,196	34%
2005	$35,608	$28,413	$7,196	20%
2006	$44,692	$31,670	$13,023	29%
2007	$66,616	$44,434	$22,183	33%
2008	$62,039	$47,342	$14,697	24%
Average	$42,347	$33,588	$8,759	21%

38 The Day-Ahead Energy Market was implemented on June 1, 2000. For the analysis presented in Table 3-19, Table 3-20 and Table 3-21, the Real-Time Energy Market LMP was used from January 1, 2000, to May 31, 2000.

Table 3-21 Real-Time and Day-Ahead Energy Market net revenues for a CP under economic dispatch scenario (Dollars per installed MW-year): Calendar years 2000 to 2008

	Real-Time Economic	Day-Ahead Economic	Actual Difference	Percent Difference
2000	$108,624	$116,784	($8,159)	(8%)
2001	$95,361	$95,119	$242	0%
2002	$96,828	$97,493	($665)	(1%)
2003	$159,912	$162,285	($2,374)	(1%)
2004	$124,497	$113,892	$10,605	9%
2005	$222,911	$220,824	$2,087	1%
2006	$177,852	$167,282	$10,571	6%
2007	$244,419	$221,757	$22,662	9%
2008	$179,457	$174,191	$5,267	3%
Average	$156,651	$152,181	$4,470	3%

Net Revenue Adequacy

To put the 2008 net revenue results in perspective, net revenues are compared to the annual, levelized fixed costs for each technology. The MMU reevaluated the fixed costs for all three new entry plant configurations for 2008.[39] The estimated, 20-year levelized fixed costs[40] are $123,640 per installed MW-year for the new entrant CT plant,[41] $171,361 per installed MW-year for the new entrant CC plant and $492,780 per installed MW-year for the new entrant CP plant.[42] Levelized fixed costs increased significantly for all three technologies. Table 3-22 shows the 20-year levelized costs for each technology for the period 2005 through 2008.[43] The increased costs of constructing generation facilities are the result of a combination of factors, including increased worldwide demand.

In this section, net revenue includes net revenue from the Real-Time Energy Market, from the Capacity Market and from any applicable ancillary service.

Table 3-22 New entrant 20-year levelized fixed costs (By plant type (Dollars per installed MW-year))

	2005	2006	2007	2008
	20-Year Levelized Fixed Cost	20-Year Levelized Fixed Cost	20-Year Levelized Fixed Cost	20-Year Levelized Fixed Cost
CT	$72,207	$80,315	$90,656	$123,640
CC	$93,549	$99,230	$143,600	$171,361
CP	$208,247	$267,792	$359,750	$492,780

39 The MMU began evaluating fixed costs for all three technologies in 2005. In the following tables and figures, the 20-year levelized fixed costs from 2005 are used as a proxy for the preceding years.

40 Annual fixed costs may vary by location. The fixed costs presented here are associated with a location in the EMAAC LDA and are meant to serve as a baseline for comparison .

41 This analysis was performed for the MMU by Pasteris Energy, Inc. The annual costs were based on a 20-year project life, 50/50 debt-to-equity financing with a target internal rate of return (IRR) of 12 percent and a debt rate of 7 percent. For depreciation, the analysis assumed a 15-year modified accelerated cost-recovery schedule (MACRS) for the CT plant and 20-year MACRS for the CC and CP plants. A general annual rate of cost inflation of 2.5 percent was utilized in all calculations.

42 Installed capacity at an average Philadelphia ambient air temperature of 54 degrees F. during the study period of 1999 to 2008.

43 The figures in Table 3-22 represent the annual cost per MW per year if total costs were levelized over the 20-year life cycle of the plant. These fixed costs of construction are specific to the PJM Mid-Atlantic Region.

In 2008, under the economic dispatch scenario, average net revenue from the PJM Real-Time Energy Market, the Capacity Market and the Ancillary Service Markets for a new entrant CT were $50,532 per installed MW-year. The associated operating costs were between $110 and $120 per MWh, based on a design heat rate of 10,500 Btu per kWh, average daily delivered natural gas prices of $9.95 per MBtu and a VOM rate of $6.47 per MWh.[44] The average PJM net revenue in 2008 would not have covered the fixed costs of a new CT. As shown in Table 3-23, the only year when average PJM net revenue was sufficient to cover fixed costs for a new CT was 1999, but zonal net revenues were sufficient to cover the fixed costs for a new CT in some cases.

Table 3-23 CT 20-year levelized fixed cost vs. real-time economic dispatch net revenue (Dollars per installed MW-year): Calendar years 1999 to 2008

	20-Year Levelized Fixed Cost	Economic Dispatch Net Revenue	Economic Dispatch Percent
1999	$72,207	$74,537	103%
2000	$72,207	$30,946	43%
2001	$72,207	$63,462	88%
2002	$72,207	$28,260	39%
2003	$72,207	$10,566	15%
2004	$72,207	$8,543	12%
2005	$72,207	$10,437	14%
2006	$80,315	$14,948	19%
2007	$90,656	$48,530	54%
2008	$123,640	$50,532	41%
Average	$80,006	$34,076	43%

Table 3-24 includes the 20-year levelized fixed cost in 2008 for a new entrant CT, the economic dispatch net revenue for each zone in 2008 and average net revenue and average fixed costs for the period 1999 to 2008. While there are no control zones with net revenue sufficient to cover 100 percent of the 2008 levelized fixed costs, the net revenues in AECO of EMAAC LDA and Pepco control zones of the SWMAAC LDA are at 99 percent of the levelized fixed cost recovery and in BGE of the SWMAAC LDA, the net revenues are 93 percent of levelized fixed cost recovery. Figure 3-3 summarizes the information in Table 3-24, showing the 2008 average net revenue for a new entrant CT, the zonal net revenue for the period 1999 to 2008 and the levelized 2008 fixed cost for a new entrant CT. The extent to which net revenues cover the levelized fixed costs of investment in the CT technology is largely dependent on location, which affects both energy and, with the implementation of the RPM construct, capacity revenue. Figure 3-4 shows zonal net revenue for the new entrant CT by LDA with the applicable yearly levelized fixed costs for the period 1999-2008.

44 The analysis used the daily gas costs and associated production costs for CTs and CCs.

Table 3-24 CT 20-year levelized fixed cost vs. real-time economic dispatch, zonal net revenue (Dollars per installed MW-year): Calendar years 1999 to 2008

	2008			10-Year Average (1999-2008)		
	Net Revenue	20-Year Levelized Cost	Percent Recovered	Net Revenue	20-Year Levelized Cost	Percent Recovered
AECO	$122,598	$123,640	99%	$49,856	$80,006	62%
AEP	$33,727	$123,640	27%	$15,871	$80,006	20%
AP	$46,970	$123,640	38%	$19,731	$80,006	25%
BGE	$115,532	$123,640	93%	$48,843	$80,006	61%
ComEd	$34,155	$123,640	28%	$18,096	$80,006	23%
DAY	$33,941	$123,640	27%	$15,843	$80,006	20%
Dominion	$72,734	$123,640	59%	$52,480	$80,006	66%
DLCO	$37,015	$123,640	30%	$17,853	$80,006	22%
DPL	$92,974	$123,640	75%	$46,155	$80,006	58%
JCPL	$92,718	$123,640	75%	$44,986	$80,006	56%
Met-Ed	$54,767	$123,640	44%	$36,313	$80,006	45%
PECO	$84,633	$123,640	68%	$42,420	$80,006	53%
PENELEC	$35,222	$123,640	28%	$27,378	$80,006	34%
Pepco	$122,845	$123,640	99%	$50,565	$80,006	63%
PPL	$50,800	$123,640	41%	$33,036	$80,006	41%
PSEG	$86,361	$123,640	70%	$43,794	$80,006	55%
RECO	$81,518	$123,640	66%	$35,307	$80,006	44%
PJM	$50,532	$123,640	41%	$34,076	$80,006	43%

Figure 3-3 New entrant CT real-time 2008 net revenue, ten-year average net revenue and 20-year levelized fixed cost as of 2008 (Dollars per installed MW-year): Calendar years 1999 to 2008

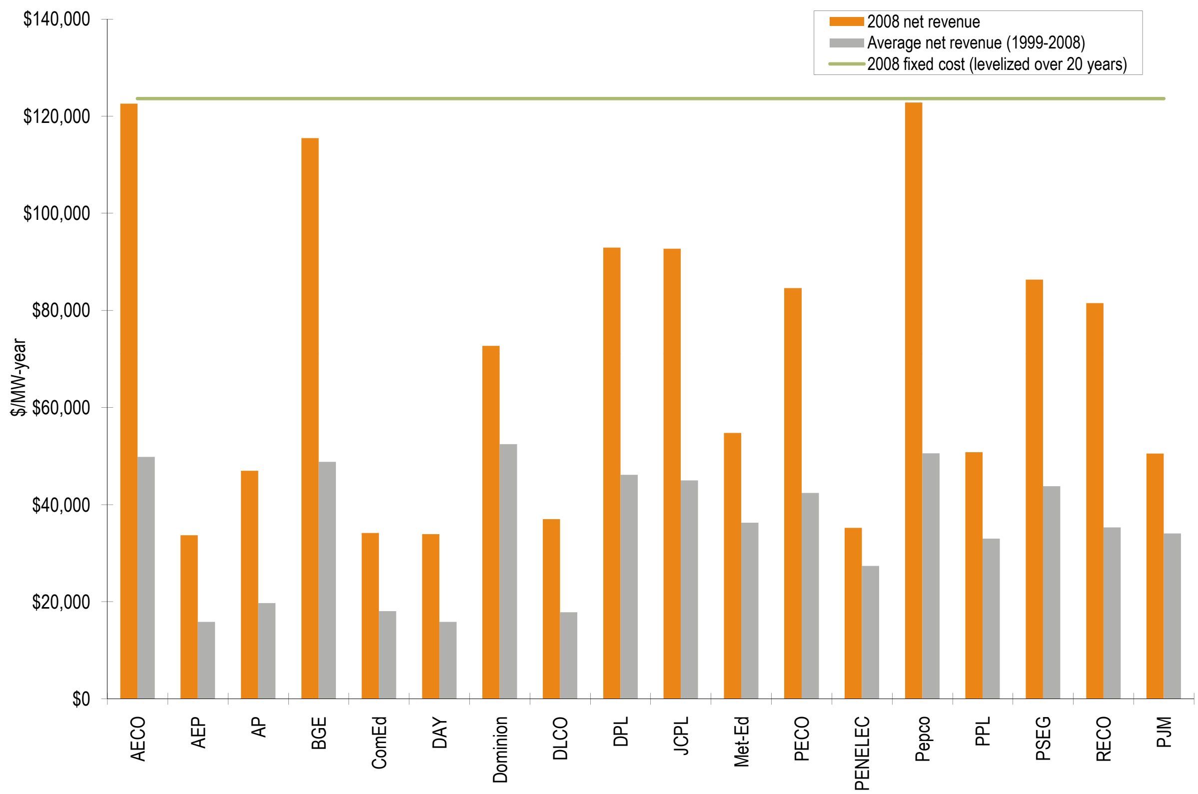
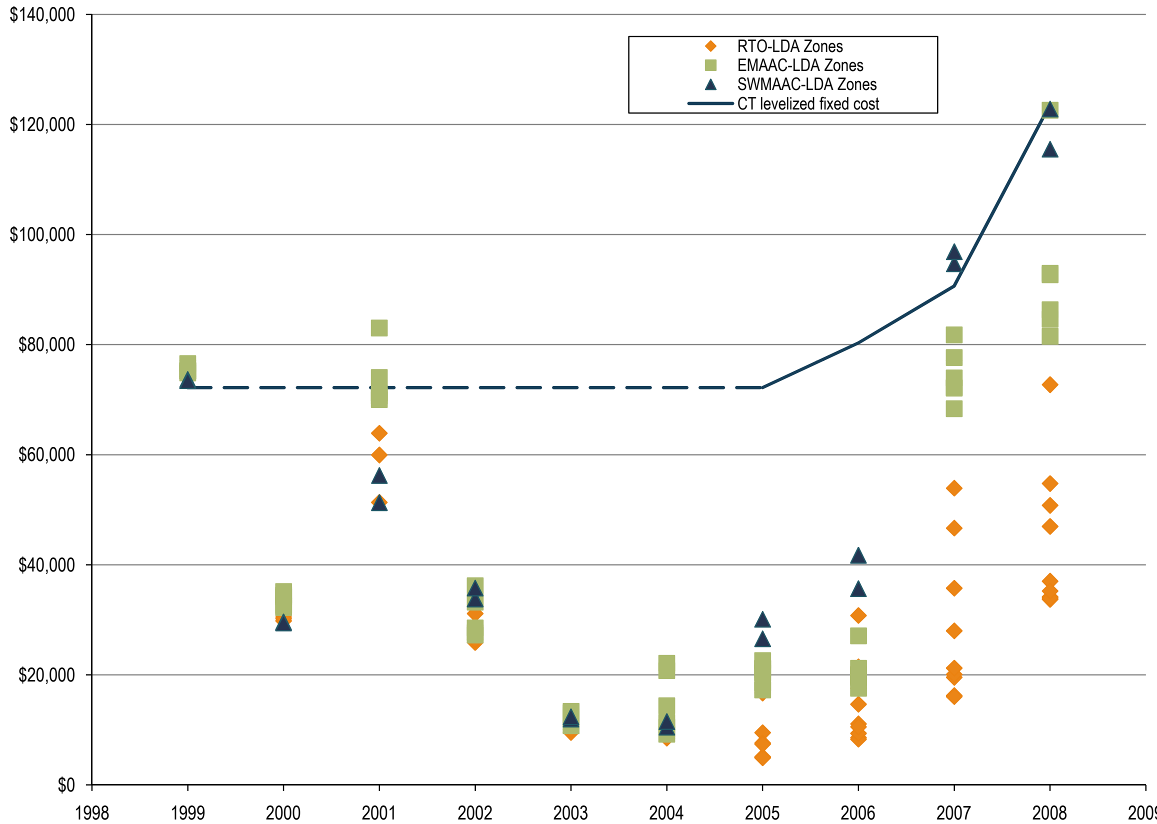


Figure 3-4 New entrant CT real-time net revenue and 20-year levelized fixed cost as of 2008 by LDA (Dollars per installed MW-year): Calendar years 1999 to 2008



In 2008, under the economic dispatch scenario, average net revenue from the PJM Real-Time Energy Market, the Capacity Market and the Ancillary Service Markets for a new entrant CC were $103,928 per installed MW-year. The associated operating costs were between $70 and $80 per MWh, based on a design heat rate of 7,150 Btu per kWh, average daily delivered natural gas prices of $9.95 per MBtu and a VOM rate of $2.80 per MWh. The resulting PJM average net revenue is less than the 20-year levelized fixed cost. Table 3-25 shows the PJM average CC net revenue and associated levelized fixed costs for the period 1999 to 2008. The only year when average PJM net revenue was sufficient to cover the associated 20-year levelized fixed costs for a new entrant CC was 1999, but zonal net revenues were sufficient to cover the fixed costs for a new CC in some cases. Average 2008 net revenue for a CC is the highest since the opening of PJM markets.

Table 3-25 CC 20-year levelized fixed cost vs. real-time economic dispatch net revenue (Dollars per installed MW-year): Calendar years 1999 to 2008

	20-Year Levelized Fixed Cost	Economic Dispatch Net Revenue	Economic Dispatch Percent
1999	$93,549	$100,700	108%
2000	$93,549	$47,592	51%
2001	$93,549	$86,670	93%
2002	$93,549	$52,272	56%
2003	$93,549	$35,591	38%
2004	$93,549	$35,785	38%
2005	$93,549	$40,817	44%
2006	$99,230	$49,529	50%
2007	$143,600	$100,809	70%
2008	$171,361	$103,928	61%
Average	$106,903	$65,369	61%

Table 3-26 compares the 20-year levelized fixed cost in 2008 for a new entrant CC to the economic dispatch net revenue for each zone in 2008, along with average net revenue for the period 1999 to 2008 and average fixed costs. While the average PJM net revenue is not enough to cover the levelized fixed costs, the net revenue for most EMAAC control zones and both SWMAAC control zones is more than sufficient in 2008 to cover the 20-year levelized fixed costs. Figure 3-5 summarizes the information in Table 3-26, showing the 2008 net revenue for a new entrant CC, the average net revenue for the period 1999 to 2008 by zone and the levelized 2008 capital cost for a new entrant CC.[45] For every zone, 2008 net revenues for a CC are greater than the ten-year average as the result of increased capacity payments and higher zonal LMPs. The extent to which net revenues cover the levelized fixed costs of investment in the CC technology is largely dependent on location, which affects both energy and, with the implementation of the RPM construct, capacity revenue. Figure 3-6 shows zonal net revenue for the new entrant CC by LDA with the applicable yearly levelized fixed costs for the period 1999-2008.

45 The fixed costs associated with the EMAAC LDA are meant to serve as a baseline for comparison.

Table 3-26 CC 20-year levelized fixed cost vs. real-time economic dispatch, zonal net revenue (Dollars per installed MW-year): Calendar years 1999 to 2008

	2008			10-Year Average (1999-2008)		
	Net Revenue	20-Year Levelized Cost	Percent Recovered	Net Revenue	20-Year Levelized Cost	Percent Recovered
AECO	$217,072	$171,361	127%	$95,344	$106,903	89%
AEP	$61,521	$171,361	36%	$36,939	$106,903	35%
AP	$101,201	$171,361	59%	$54,086	$106,903	51%
BGE	$207,969	$171,361	121%	$90,744	$106,903	85%
ComEd	$63,092	$171,361	37%	$45,405	$106,903	42%
DAY	$62,081	$171,361	36%	$36,424	$106,903	34%
Dominion	$155,658	$171,361	91%	$120,575	$106,903	113%
DLCO	$61,141	$171,361	36%	$36,346	$106,903	34%
DPL	$180,121	$171,361	105%	$88,106	$106,903	82%
JCPL	$189,725	$171,361	111%	$87,709	$106,903	82%
Met-Ed	$131,566	$171,361	77%	$73,498	$106,903	69%
PECO	$165,660	$171,361	97%	$80,947	$106,903	76%
PENELEC	$77,299	$171,361	45%	$54,225	$106,903	51%
Pepco	$219,105	$171,361	128%	$93,292	$106,903	87%
PPL	$124,566	$171,361	73%	$67,765	$106,903	63%
PSEG	$182,551	$171,361	107%	$90,267	$106,903	84%
RECO	$171,658	$171,361	100%	$91,617	$106,903	86%
PJM	$103,928	$171,361	61%	$65,369	$106,903	61%

Figure 3-5 New entrant CC real-time 2008 net revenue, ten-year average net revenue and 20-year levelized fixed cost as of 2008 (Dollars per installed MW-year): Calendar years 1999 to 2008

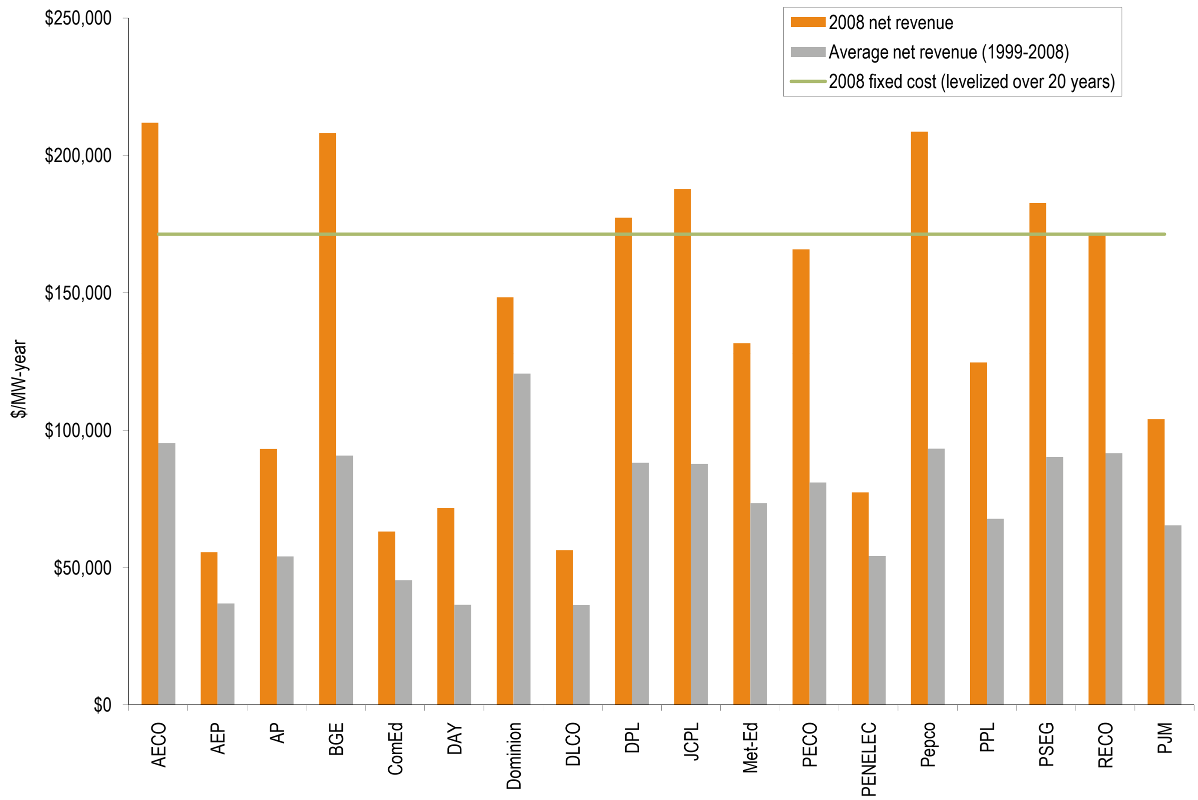
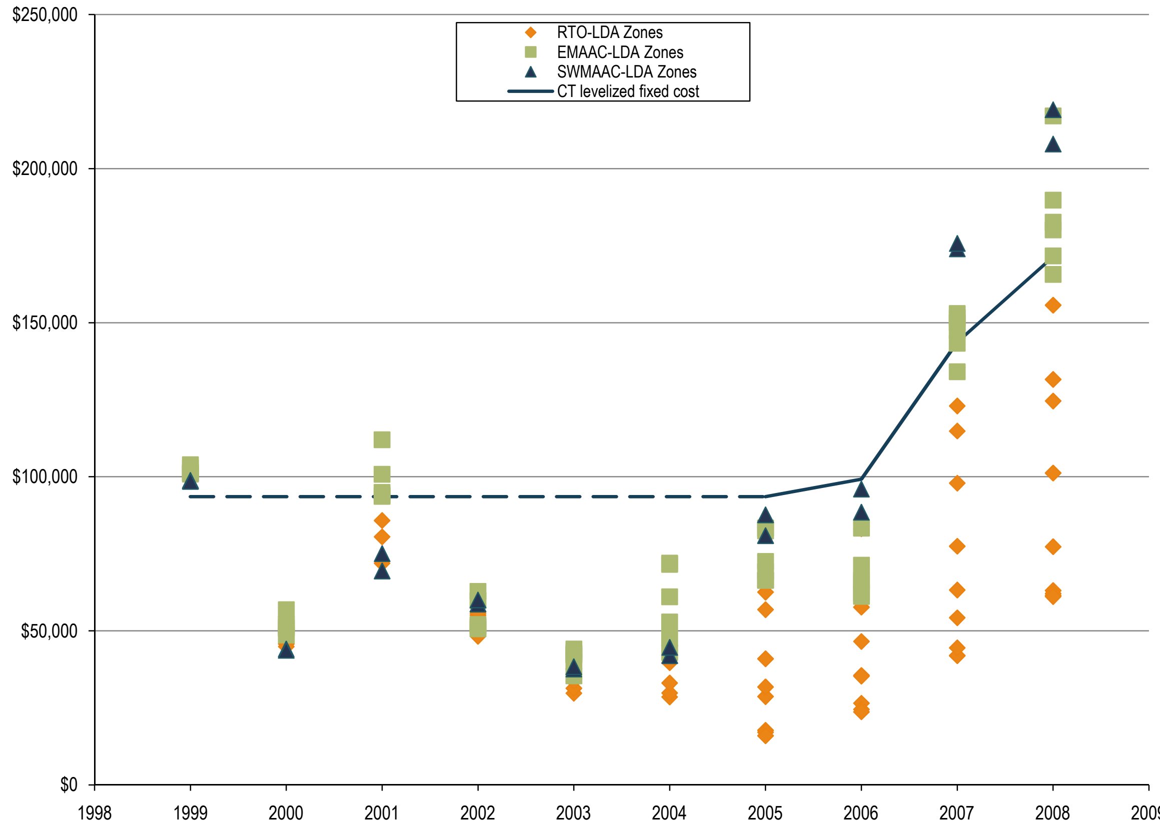


Figure 3-6 New entrant CC real-time net revenue and 20-year levelized fixed cost as of 2008 by LDA (Dollars per installed MW-year): Calendar years 1999 to 2008



In 2008, under the economic dispatch scenario, average PJM net revenue from the Real-Time Energy Market, the Capacity Market and the Ancillary Service Markets for a new entrant CP was $216,929 per installed MW-year. The associated operating costs were between $40 and $50 per MWh, based on a design heat rate of 9,000 Btu per kWh, average delivered coal prices of $4.60 per MBtu and a VOM rate of $3.00 per MWh.[46] Table 3-27 shows the PJM average CP net revenue and associated levelized fixed costs for the period 1999 to 2008. For the period, the resulting PJM average net revenue is less than the 20-year levelized fixed cost. The only year when average PJM net revenue was sufficient to cover the levelized fixed costs for a new entrant CP was 2005, but zonal net revenues were sufficient to cover the fixed costs for a new CP in some cases. Average 2008 net revenue for a CP shows a significant decrease from 2007 reflecting the higher cost of coal.

46 The analysis used the prompt coal costs and associated production costs for CPs.

Table 3-27 CP 20-year levelized fixed cost vs. real-time economic dispatch net revenue (Dollars per installed MW-year): Calendar years 1999 to 2008

	20-Year Levelized Fixed Cost	Economic Dispatch Net Revenue	Economic Dispatch Percent
1999	$208,247	$118,022	57%
2000	$208,247	$134,564	65%
2001	$208,247	$129,271	62%
2002	$208,247	$112,131	54%
2003	$208,247	$169,509	81%
2004	$208,247	$133,124	64%
2005	$208,247	$228,430	110%
2006	$267,792	$182,461	68%
2007	$359,750	$277,284	77%
2008	$492,780	$218,144	44%
Average	$231,697	$164,977	71%

Table 3-28 compares the 20-year levelized fixed cost in 2008 for a new entrant CP to the economic dispatch net revenue for each zone in 2008, along with average net revenue for the period 1999 to 2008 and average fixed costs. There were no control zones with sufficient net revenue to cover the 2008 levelized fixed costs. Figure 3-7 summarizes the information in Table 3-28, showing the 2008 net revenue for a new entrant CP, the average net revenue for the period 1999 to 2008 by zone and the levelized 2008 capital cost for a new entrant CP.[47] For every zone, 2008 energy net revenues for a CP are lower than 2007, which is partially offset by higher capacity revenues.[48] The extent to which net revenues cover the levelized fixed costs of investment in the CP technology is largely dependent on location, which affects both energy and, with the implementation of the RPM construct, capacity revenue. Figure 3-8 shows zonal net revenue for the new entrant CP by LDA with the applicable yearly levelized fixed costs for the period 1999-2008.

47 The fixed costs associated with the EMAAC LDA are meant to serve as a baseline for comparison.
48 Average net revenues were taken for all years a zone was fully integrated into PJM.

Table 3-28 CP 20-year levelized fixed cost vs. real-time economic dispatch, zonal net revenue (Dollars per installed MW-year): Calendar years 1999 to 2008

	2008			10-Year Average (1999-2008)		
	Net Revenue	20-Year Levelized Cost	Percent Recovered	Net Revenue	20-Year Levelized Cost	Percent Recovered
AECO	$396,564	$492,780	80%	$216,008	$231,697	93%
AEP	$182,201	$492,780	37%	$157,624	$231,697	68%
AP	$288,025	$492,780	58%	$205,040	$231,697	88%
BGE	$379,157	$492,780	77%	$210,919	$231,697	91%
ComEd	$234,487	$492,780	48%	$166,700	$231,697	72%
DAY	$160,462	$492,780	33%	$147,287	$231,697	64%
Dominion	$312,361	$492,780	63%	$293,753	$231,697	127%
DLCO	$168,837	$492,780	34%	$140,294	$231,697	61%
DPL	$379,118	$492,780	77%	$211,863	$231,697	91%
JCPL	$374,645	$492,780	76%	$206,616	$231,697	89%
Met-Ed	$312,370	$492,780	63%	$190,800	$231,697	82%
PECO	$349,522	$492,780	71%	$200,126	$231,697	86%
PENELEC	$269,748	$492,780	55%	$166,600	$231,697	72%
Pepco	$397,620	$492,780	81%	$215,416	$231,697	93%
PPL	$316,263	$492,780	64%	$184,537	$231,697	80%
PSEG	$307,268	$492,780	62%	$209,743	$231,697	91%
RECO	$318,225	$492,780	65%	$256,437	$231,697	111%
PJM	$218,144	$492,780	44%	$170,294	$231,697	73%

Figure 3-7 New entrant CP real-time 2008 net revenue, ten-year average net revenue and 20-year levelized fixed cost as of 2008 (Dollars per installed MW-year): Calendar years 1999 to 2008

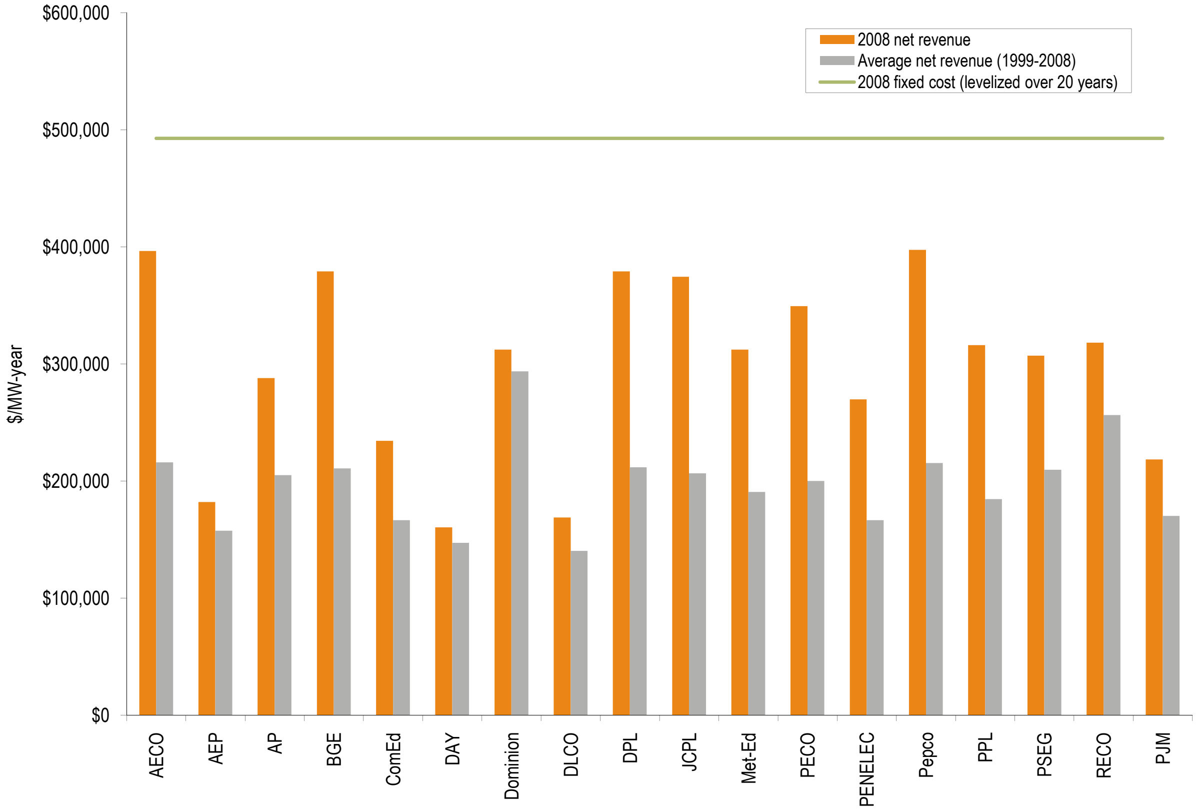
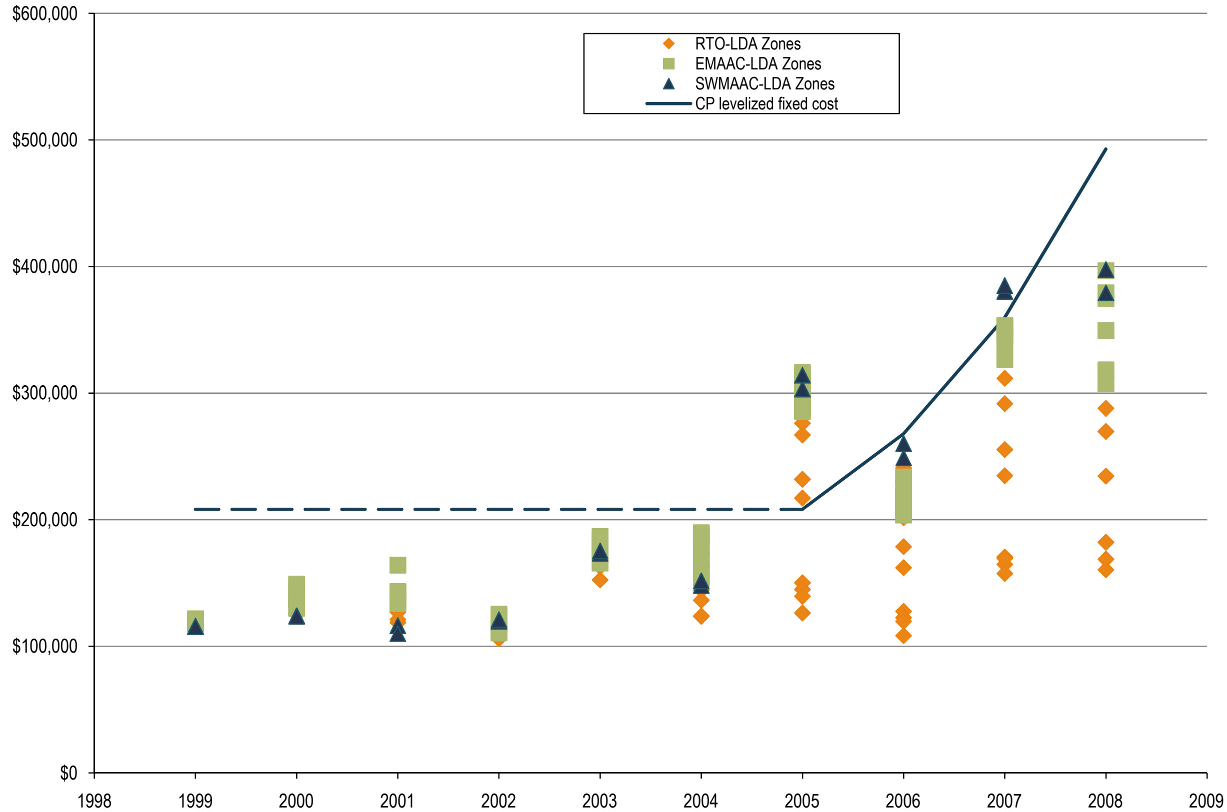


Figure 3-8 New entrant CP real-time net revenue and 20-year levelized fixed cost as of 2008 by LDA (Dollars per installed MW-year): Calendar years 1999 to 2008



Although it can be expected that in the long run, in a competitive market, net revenue from all sources will cover the fixed costs of investing in new generating resources, including a competitive return on investment, actual results are expected to vary from year to year. Wholesale energy markets, like other markets, are cyclical. When the markets are long, prices will be lower and when the markets are short, prices will be higher. Analysis of 2008 net revenue indicates that the degree to which fixed costs of new peaking, midmerit and coal-fired baseload plants are covered depends on the location of the new plant, which affects both Energy Market net revenue and the Capacity Market net revenue resulting from the RPM. Additionally, the net revenue for a new generation resource varied significantly with the input fuel type and the efficiency of the reference technology. As the delivered price of coal increased on average by about 82.1 percent, no control zones showed sufficient revenue to recover 20-year levelized capital costs in 2008.[49] While average natural gas prices increased by 26.4 percent, there were fewer hours of high demand and high price levels. As a result, Energy Market net revenue for a CT in most zones decreased which was partially offset by increased Capacity Market net revenue. While there are no control zones with net revenue sufficient to cover 100 percent of the 2008 levelized fixed costs, the net revenues in AECO of EMAAC LDA and Pepco control zones of the SWMAAC LDA are at 99 percent of the levelized fixed

49 The calculated increase in delivered cost of coal is based on Central Appalachian, low-sulfur coal used in PJM RTO net revenue calculations.

cost recovery and, in BGE of the SWMAAC LDA, the net revenues are 93 percent of levelized fixed cost recovery. Net revenue from the combined cycle technology was sufficient to recover the 20-year levelized fixed costs in a number of zones as a result of locational pricing in both the Energy and Capacity Markets.

The net revenue results illustrate some fundamentals of the PJM wholesale power market. CTs are generally the highest incremental cost units and therefore tend to be marginal in the energy market and set prices, when they run. When this occurs, CT energy market net revenues are small and there is little contribution to fixed costs. High demand hours result in less efficient CTs setting prices, which results in higher net revenues for more efficient CTs. There were relatively few high demand days in 2008. Scarcity revenues in the energy market also contribute to covering fixed costs, when they occur, but scarcity revenues are not a predictable and systematic source of net revenue. In the PJM design, the balance of the net revenue required to cover the fixed costs of peaking units comes from the Capacity Market. However, when the actual fixed costs of capacity increase rapidly, there is a corresponding lag in Capacity Market prices which will tend to lead to an under recovery of the fixed costs of CTs. That is what occurred in 2008. The fixed costs of a CT in 2008 are substantially higher than the fixed costs of a CT in 2007, but the clearing prices in the Capacity Market reflect the prior, lower costs of a CT that were incorporated in the demand curve for the auctions that determined prices in the 2007/2008 and 2008/2009 RPM auctions.

The net revenue performance of combined cycle units (CCs) was significantly better than that of CTs. CCs, like CTs, burn gas but are more efficient than CTs and therefore as clearing prices set by CTs increase, net revenues from the Energy Market increase for CCs. These inframarginal energy revenues were the source of the higher CC net revenues in 2008.

Coal units (CP) are marginal in the PJM system for a substantial number of hours. When this occurs, CP energy market net revenues are small and there is little contribution to fixed costs. When less efficient coal units are on the margin net revenues are higher for more efficient coal units. Coal units also received higher net revenues as a result of CTs setting prices based on higher gas costs, when they ran. But these higher net revenues were offset by higher coal costs.

The returns earned by investors in generating units are a direct function of net revenues. Positive returns may be earned at less than the annualized fixed costs, although the returns are less than the target. A sensitivity analysis was performed to determine the impact of changes in net revenue on the return on investment for a new generating unit. The internal rate of return (IRR) was calculated for a range of 20-year levelized net revenue streams, using 20-year levelized fixed costs from Table 3-22 . Levelized net revenues were modified and the IRR calculated. A $7,500 per MW-year sensitivity was used for the CT; a $10,000 per MW-year sensitivity was used for the CC; and a $30,000 per MW-year sensitivity was used for the CP generator. The results are shown in Table 3-29.[50]

50 This analysis was performed for the MMU by Pasteris Energy, Inc. The annual costs were based on a 20-year project life, 50/50 debt-to-equity financing with a target IRR of 12 percent and a debt rate of 7 percent. For depreciation, the analysis assumed a 15-year modified accelerated cost-recovery schedule (MACRS) for the CT plant and 20-year MACRS for the CC and CP plants. A general annual rate of cost inflation of 2.5 percent was utilized in all calculations.

Table 3-29 Internal rate of return sensitivity for CT, CC and CP generators

	CT		CC		CP	
	20-Year Levelized Net Revenue	20-Year After Tax IRR	20-Year Levelized Net Revenue	20-Year After Tax IRR	20-Year Levelized Net Revenue	20-Year After Tax IRR
Sensitivity 1	$131,140	13.6%	$181,361	13.5%	$522,780	13.8%
Base Case	$123,640	12.0%	$171,361	12.0%	$492,780	12.0%
Sensitivity 2	$116,140	10.3%	$161,361	10.4%	$462,780	10.2%
Sensitivity 3	$108,640	8.6%	$151,361	8.8%	$432,780	8.2%
Sensitivity 4	$101,140	6.7%	$141,361	7.1%	$402,780	6.2%
Sensitivity 5	$93,640	4.7%	$131,361	5.3%	$372,780	3.9%
Sensitivity 6	$86,140	2.3%	$121,361	3.3%	$342,780	1.4%

Existing and Planned Generation

Installed Capacity and Fuel Mix

During calendar year 2008, PJM installed capacity rose slightly from 164,277 MW on January 1 to 164,895 MW on December 31, and the fuel mix also shifted slightly. Installed capacity includes net capacity imports and exports and can vary on a daily basis.

Installed Capacity

On January 1, 2008, PJM installed capacity was 164,277 MW.[51] (See Table 3-30.) Over the next five months, unit retirements, facility reratings plus import and export shifts changed installed capacity to 163,752 MW on May 31, 2008.[52]

Table 3-30 PJM installed capacity (By fuel source): January 1, May 31, June 1, and December 31, 2008

	1-Jan-08		31-May-08		1-Jun-08		31-Dec-08	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Coal	66,378	40.4%	66,334	40.5%	66,155	40.3%	67,065	40.7%
Oil	10,640	6.5%	10,638	6.5%	10,730	6.5%	10,715	6.5%
Gas	47,852	29.1%	47,728	29.1%	48,530	29.6%	48,340	29.3%
Nuclear	30,884	18.8%	30,884	18.9%	30,472	18.6%	30,468	18.5%
Solid waste	712	0.4%	712	0.4%	665	0.4%	665	0.4%
Hydroelectric	7,746	4.7%	7,391	4.5%	7,476	4.6%	7,476	4.5%
Wind	65	0.0%	65	0.0%	151	0.1%	166	0.1%
Total	164,277	100.0%	163,752	100.0%	164,179	100.0%	164,895	100.0%

51 Percents shown in Table 3-30 and Table 3-31 are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.
52 The capacity described in this section is the capability of all PJM capacity resources, as entered into the eRPM system, regardless of whether the capacity cleared in the RPM auctions.

At the beginning of the new planning year on June 1, 2008, installed capacity increased by 427 MW to 164,179 MW, a .26 percent increase in total PJM capacity over the May 31 level.

On December 31, 2008, PJM installed capacity was 164,895 MW.[53]

Energy Production by Fuel Source

In calendar year 2008, coal and nuclear units provided 89.6 percent, gas 7.3 percent, oil 0.3 percent, hydroelectric 1.7 percent, solid waste 0.7 percent and wind 0.5 percent of total generation.[54] (See Table 3-31.)

Table 3-31 PJM generation (By fuel source (GWh)): Calendar year 2008

	GWh	Percent
Coal	404,719.1	55.0%
Gas	53,552.4	7.3%
Hydroelectric	12,341.3	1.7%
Nuclear	254,379.2	34.6%
Oil	1,918.1	0.3%
Solar	0.0	0.0%
Solid Waste	5,020.8	0.7%
Wind	3,313.4	0.5%
Total	735,244.3	100.0%

Planned Generation Additions

Net revenues provide incentives to build new generation to serve PJM markets. While these incentives operate with a significant lag time and are based on expectations of future net revenue, the amount of planned new generation in PJM reflects the market's perception of the incentives provided by the combination of revenues from the PJM Energy, Capacity and Ancillary Service Markets. At the end of 2008, 90,807 MW of capacity were in generation request queues for construction through 2018, compared to an average installed capacity of approximately 164,000 MW in 2008 and a year-end, installed capacity of 164,895 MW. Although it is clear that not all generation in the queues will be built, PJM has added capacity annually since 2000. (See Table 3-32.)

53 Wind-based resources accounted for 166.4 MW of installed capacity in PJM on December 31, 2008. This value represents approximately 13 percent of wind nameplate capability in PJM. PJM administratively reduces the capabilities of all wind generators to 13 percent of nameplate capacity when determining the system installed capacity because wind resources cannot be assumed to be available on peak and cannot respond to dispatch requests. As data become available, unforced capability of wind resources will be calculated using actual data in place of the 87 percent reduction. There are additional wind resources not reflected in this total because they are energy only resources and do not participate in the PJM Capacity Market.

54 Gas includes landfill gas and natural gas.

Table 3-32 Year-to-year capacity additions: Calendar years 2000 to 2008

	MW
2000	505
2001	872
2002	3,841
2003	3,524
2004	1,935
2005	819
2006	471
2007	1,265
2008	2,777

A more detailed examination of the queue data reveals some additional conclusions. The geographic distribution of generation in the queues shows that new capacity is being added disproportionately in the west. The geographic distribution of units by fuel type in the queues, when combined with data on unit age, suggests that reliance on natural gas as a fuel in the east will increase.

PJM Generation Queues

Generation request queues are groups of proposed projects. Queue A was open from February 1997 through January 1998; Queue B was open from February 1998 through January 1999; Queue C was open from February 1999 through July 1999 and Queue D opened in August 1999. After Queue D, a new queue was opened every six months. Queue U was active through January 31, 2008.

Capacity in generation request queues for the 11-year period beginning in 2008 and ending in 2018 increased by 25,853 MW from 64,954 MW in 2007 to 90,807 MW in 2008. (See Table 3-33.)[55, 56] Queued capacity scheduled for service in 2008 decreased from 11,636 MW to 7,037 MW, or 40 percent. Queued capacity scheduled for service in 2009 decreased from 10,377 MW to 9,023 MW, or 13 percent. Capacity in the queues for the years 2009 through 2014 increased in 2008 over 2007. Queued capacity scheduled for service in 2015 decreased from 3,234 MW to 2,436 MW, a decrease of 25 percent. Queued capacity scheduled for service in 2016 decreased from 1,640 MW to 0 MW. Queued capacity scheduled for service in 2018 increased from 0 MW to 1,594 MW.

55 See the *2007 State of the Market Report* (March 11, 2008), pp. 146-147, for the queues in 2007.

56 The 90,807 MW includes generation with scheduled in-service dates in 2008 and units still active in the queue with in-service dates scheduled before 2008, listed at nameplate capacity.

Table 3-33 Queue comparison (MW): Calendar years 2008 vs. 2007

	MW in the Queue 2007	MW in the Queue 2008	Year-to-Year Change (MW)	Year-to-Year Change
2008	11,636	7,037	(4,599)	(40)%
2009	10,377	9,023	(1,354)	(13)%
2010	11,464	18,052	6,588	57%
2011	17,653	17,253	(400)	(2)%
2012	5,520	15,527	10,007	181%
2013	1,660	7,920	6,260	377%
2014	1,770	11,965	10,195	576%
2015	3,234	2,436	(798)	(25)%
2016	1,640	0	(1,640)	(100)%
2018	0	1,594	1,594	NA
Total	64,954	90,807	25,853	40%

Table 3-34 shows the amount of capacity active, in-service, under construction or withdrawn for each queue since the beginning of the Regional Transmission Expansion Plan (RTEP) Process and the total amount of capacity that had been included in each queue.[57]

57 Projects listed as active have been entered in the queue and the next phase can be under construction, in-service or withdrawn. At any time, the total number of projects in the queues is the sum of active projects and under-construction projects.

Table 3-34 Capacity in PJM queues (MW): At December 31, 2008 [58, 59]

Queue	Active	In-Service	Under Construction	Withdrawn	Total
A Expired 31-Jan-98	0	8,933	0	18,287	27,220
B Expired 31-Jan-99	0	4,613	0	15,882	20,495
C Expired 31-Jul-99	0	531	0	4,100	4,631
D Expired 31-Jan-00	0	768	0	7,069	7,836
E Expired 31-Jul-00	0	795	0	17,637	18,433
F Expired 31-Jan-01	0	52	0	3,093	3,145
G Expired 31-Jul-01	0	486	630	22,457	23,573
H Expired 31-Jan-02	0	560	143	8,422	9,124
I Expired 31-Jul-02	0	110	0	4,903	5,013
J Expired 31-Jan-03	0	36	0	862	898
K Expired 31-Jul-03	0	189	20	2,495	2,704
L Expired 31-Jan-04	20	256	165	3,849	4,290
M Expired 31-Jul-04	0	204	293	4,084	4,581
N Expired 31-Jan-05	790	2,168	97	6,648	9,703
O Expired 31-Jul-05	2,589	509	409	3,865	7,372
P Expired 31-Jan-06	4,266	709	1,625	2,242	8,842
Q Expired 31-Jul-06	6,782	669	2,423	5,457	15,331
R Expired 31-Jan-07	10,095	614	106	12,007	22,822
S Expired 31-Jul-07	12,190	530	222	7,967	20,909
T Expired 31-Jan-08	23,564	106	142	2,166	25,978
U Expired 31-Jan-09	24,229	20	8	0	24,256
Total	84,524	22,857	6,283	153,491	267,156

Data presented in Table 3-34 show that 59 percent of total in-service capacity from all the queues was from Queues A and B and an additional 9 percent was from Queues C, D and E.[60]

The data presented in Table 3-35 show that for successful projects there is an average time of 700 days (i.e., 1.9 years) between entering a queue and the in-service date. The data also show that for withdrawn projects, there is an average time of 541 days (i.e., 1.5 years) between entering a queue and exiting. For each status, there is substantial variability around the average results.

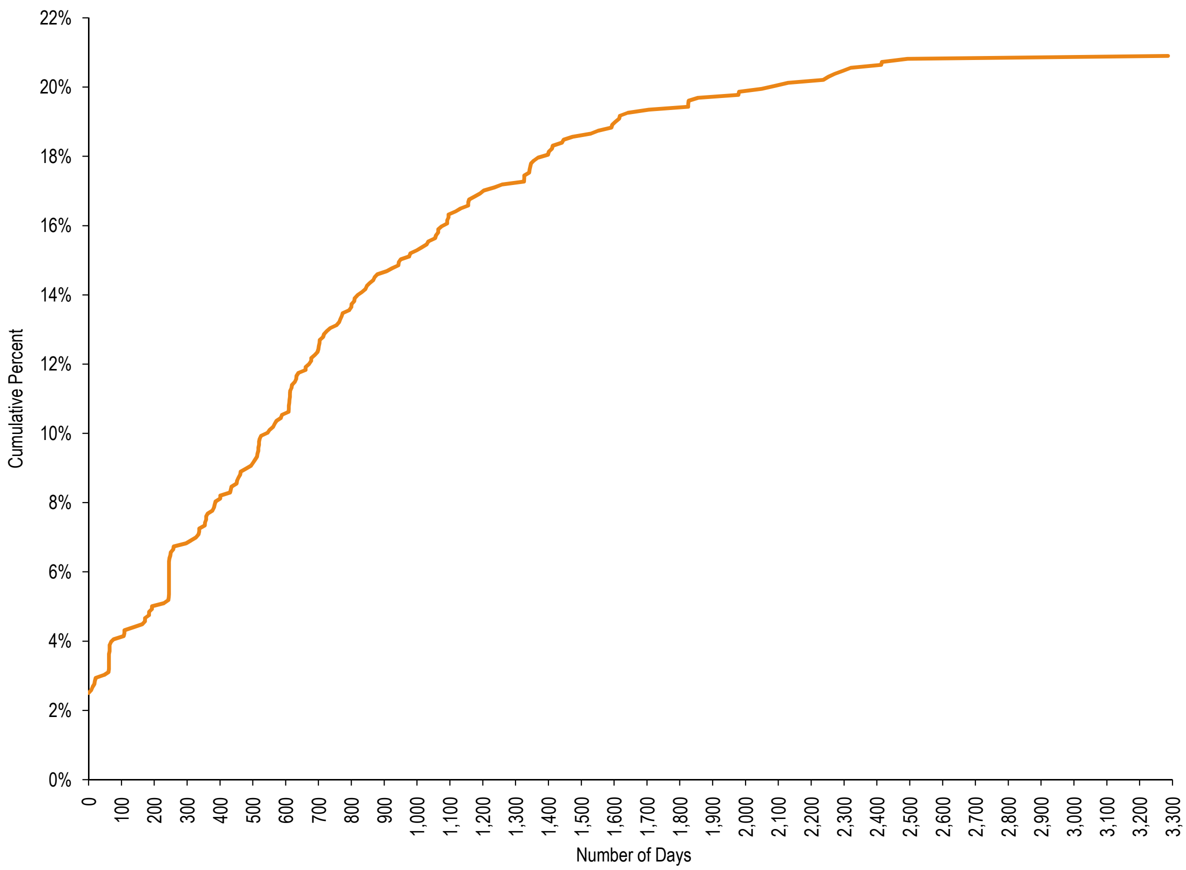
Table 3-35 Average project queue times: At December 31, 2008

Status	Average (Days)	Standard Deviation	Minimum	Maximum
In-Service	700	626	0	3287
Under Construction	1,132	984	0	4370
Withdrawn	541	565	0	2710
Active	1,069	633	0	3390

58 The *2008 State of the Market Report* contains all projects in the queue including reratings of existing generating units and energy only resources.
59 Projects listed as partially in-service are counted as in-service for the purposes of this analysis.
60 The data for Queue U include projects through December 31, 2008

Figure 3-9 shows the cumulative probability of completion of RTEP projects. The first queue (Queue A) was opened more than 4,000 days ago and the final active project in the A Queue was completed in 2006. The final project was in the queue for 3,287 days and this is the upper limit of Figure 3-9. The data show that about 10.0 percent of all projects in the queue are completed within 546 days and about 20.8 percent of the projects are completed within 3,287 days.

Figure 3-9 RTEP project completion probability as function of days in queue



Distribution of Units in the Queues

Table 3-36 shows the RTEP projects under construction or active as of December 31, 2008, by unit type and control zone. Most (90.2 percent of the MW) of the steam projects (predominantly coal) and most of the wind projects (93.3 percent of the MW) are outside the Eastern MAAC (EMAAC)[61] and Southwestern MAAC (SWMAAC)[62] locational deliverability areas (LDAs).[63] Much (44 percent of the MW) of the combined-cycle projects are in EMAAC and SWMAAC. Wind projects account for approximately 43,784 MW of capacity or 48 percent of the capacity in the queues and CC

61 EMAAC consists of the AECO, DPL, JCPL, PECO and PSEG control zones.
62 SWMAAC consists of the BGE and Pepco control zones.
63 See the *2008 State of the Market Report*, Volume II, Appendix A, "PJM Geography" for a map of PJM LDAs.

projects account for 22,724.1 MW of capacity or 25 percent of the capacity in the queues.[64] Of the total capacity additions, only about 16,847 MW or 18.5 percent are projected to be in zones that are in EMAAC; about 3,536.5 MW or 3.9 percent are projected to be constructed in zones that are in SWMAAC.

Table 3-36 Capacity additions in active or under-construction queues by control zone (MW): At December 31, 2008

	CC	CT	Diesel	Hydro	Nuclear	Steam	Wind	Unknown	Total
AECO	440	956	7	0	0	670	1,416	0	3,489
AEP	1,035	594	185	150	84	3,728	7,130	0	12,906
AP	1,300	606	6	210	0	1,478	2,095	0	5,695
BGE	100	335	4	0	0	0	0	0	439
ComEd	1,300	851	94	0	298	726	27,243	44	30,556
DLCO	0	0	0	87	75	0	0	0	162
DPL	0	284	0	0	0	23	1,500	30	1,837
DAY	0	10	2	0	0	12	847	0	871
Dominion	3,613	998	21	94	1,944	326	230	169	7,395
JCPL	2,750	40	30	1	0	15	0	0	2,836
Met-Ed	2,595	1,032	49	0	24	0	0	0	3,700
ODEC	0	9	0	0	0	0	0	0	9
PECO	3,180	595	0	0	140	21	0	0	3,936
PENELEC	0	161	6	32	0	350	2,697	0	3,245
Pepco	1,195	239	4	0	1,640	0	0	20	3,098
PPL	2,836	112	23	143	1,707	149	626	153	5,748
PSEG	2,380	1,254	67	1,000	43	0	0	0	4,744
RECO	0	6	0	0	0	0	0	0	6
UGI	0	135	0	0	0	0	0	0	135
Total	22,724	8,216	499	1,715	5,955	7,499	43,784	416	90,807

Table 3-37 shows existing generators by unit type and control zone. Existing steam (mainly coal and residual oil) and nuclear capacity are distributed across control zones.

A potentially significant change in the distribution of unit types within the PJM footprint is likely as a combined result of the location of generation resources in the queue (Table 3-36) and the location of units likely to retire. In both the EMAAC and SWMAAC LDAs, the capacity mix is likely to shift to more natural gas-fired CC and combustion turbine (CT) capacity. Elsewhere in the PJM footprint, continued reliance on steam (mainly coal) seems likely.

64 Since wind resources cannot be dispatched on demand, PJM rules previously required that the unforced capacity of wind resources be derated to 20 percent until actual generation data are available. Beginning with Queue U, PJM derates wind resources to 13 percent. Based on the derating of 43,784 MW of wind resources, the 90,807 MW currently active in the queues would be reduced to 55,132 MW.

Table 3-37 Existing PJM capacity 2008 (By zone and unit type (MW))

	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	Wind	Total
AECO	155	528	17	0	0	1,108	8	1,816
AEP	4,272	2,773	0	1,011	2,093	21,015	0	31,164
AP	1,129	264	43	80	0	7,878	81	9,475
BGE	0	872	0	0	1,735	2,897	0	5,504
ComEd	1,790	6,404	0	0	11,448	7,094	734	27,470
DAY	0	1,316	44	0	0	4,805	0	6,165
DLCO	272	45	0	0	1,630	3,524	0	5,471
DPL	1,088	801	88	0	0	1,825	0	3,802
Dominion	2,515	3,226	105	3,321	3,459	8,342	0	20,968
External	0	0	6	0	0	5,645	0	5,652
JCPL	770	1,224	13	400	619	10	0	3,036
Met-Ed	1,370	417	0	19	786	819	0	3,411
PECO	2,497	1,503	6	1,618	4,492	2,022	0	12,138
PENELEC	0	332	35	495	0	6,805	119	7,786
Pepco	1,134	1,317	0	0	0	4,781	0	7,232
PPL	1,674	462	34	568	2,289	5,515	113	10,655
PSEG	2,933	2,993	21	11	3,353	2,279	0	11,590
Total	21,599	24,477	411	7,523	31,904	86,364	1,055	173,334

Table 3-38 shows the age of PJM generators by unit type. If the age profile of steam units in PJM accurately represents the future age profile, significant and disproportionate retirements of steam units will occur within the next 10 to 20 years. While steam units comprise 49.8 percent of all current MW, steam units 40 years of age and older comprise 86.7 percent of all MW 40 years of age and older and nearly 96.7 percent of such MW if hydroelectric is excluded from the total. Approximately 6,461 MW of steam units 40 years of age and older are located in EMAAC and SWMAAC.

Table 3-38 PJM capacity age (MW)

Age (years)	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	Wind	Total
Less than 10	16,061	14,337	98	122	0	1,281	1,055	32,954
10 to 20	4,978	2,977	76	55	3,533	7,109	0	18,729
20 to 30	0	86	56	3,112	14,914	9,090	0	27,258
30 to 40	560	6,173	87	703	13,457	39,267	0	60,247
40 to 50	0	904	91	2,217	0	20,186	0	23,398
50 to 60	0	0	4	354	0	9,267	0	9,625
60 to 70	0	0	0	107	0	164	0	271
70 to 80	0	0	0	553	0	0	0	553
80 to 90	0	0	0	138	0	0	0	138
90 to 100	0	0	0	132	0	0	0	132
100 and over	0	0	0	29	0	0	0	29
Total	21,599	24,477	411	7,523	31,904	86,364	1,055	173,334

There are potentially significant implications for future congestion, the role of firm and interruptible gas supply and natural gas supply infrastructure, if older steam units in the EMAAC and SWMAAC LDAs are replaced by units burning natural gas. Table 3-39 shows that in the EMAAC LDA, gas-consuming unit types dominate the capacity additions, accounting for approximately 70.5 percent of the slated capacity additions. Steam additions (coal) account for about 4.3 percent of the MW and wind projects account for 17.3 percent of the MW in the queue for the EMAAC LDA. It should be noted that the wind capacity in Table 3-39 is reported at nameplate capacity and not reduced to 20 percent of nameplate. Nuclear and gas capacity comprise 99.2 percent of the MW capacity additions in the SWMAAC LDA.

Table 3-39 Capacity additions in active or under-construction queues by LDA (MW): At December 31, 2008

	CC	CT	Diesel	Hydro	Nuclear	Steam	Wind	Unknown	Total
EMAAC	8,750	3,134	104	1,001	183	730	2,916	30	16,847
Non-MAAC	7,248	3,203	309	540	2,401	6,270	37,545	213	57,729
SWMAAC	1,295	574	8	0	1,640	0	0	20	3,537
WMAAC	5,431	1,305	78	175	1,731	499	3,323	153	12,694
Total	22,724	8,216	499	1,715	5,955	7,499	43,784	416	90,807

Table 3-40 shows the effect that the new generation in the queues would have on the existing generation mix, assuming that all non-hydroelectric generators in excess of 40 years of age retire by 2018. In 2018, CC and CT generators would account for 57.3 percent of EMAAC generation, an increase of 12.5 percentage points from 2008 levels. Accounting for the fact that about 1123 MW of steam units over 40 years old are gas-fired, the result would be an increase in the proportion of gas-fired capacity in EMAAC from about 44.8 percent to about 57 percent. This proportion of gas-fired capacity in EMAAC would increase to 60.4 percent if the 80 percent reduction for wind capacity is taken into account for EMAAC, meaning that the effective capacity additions are 14,508 MW.

The exact expected role of gas-fired generation depends largely on projects in the queues. There is a planned addition of 1640 MW of nuclear capacity in SWMAAC.

Without the planned coal-fired capability in EMAAC, new gas-fired capability would represent 74 percent of all new capability in EMAAC and 86 percent when the 80 percent reduction for wind capability is included. In 2018 this would mean that CC and CT generators would comprise 61.4 percent of total capability in EMAAC.

Without the planned nuclear capability in SWMAAC, new gas-fired capability would represent nearly 100 percent of all new capability in the SWMAAC. In 2018 this would mean that CC and CT generators would comprise 43.8 percent of total capability in SWMAAC.

Table 3-40 Comparison of generators 40 years and older with slated capacity additions (MW): Through 2018 [65]

Area	Unit Type	Capacity of Generators 40 Years or Older	Percent of Area Total	Capacity of Generators of All Ages	Percent of Area Total	Additional Capacity through 2018	Estimated Capacity 2018	Percent of Area Total
EMAAC	Combined cycle	0	0.0%	7,443	23.0%	8,750	16,193	36.0%
	Combustion turbine	620	10.3%	7,049	21.8%	3,134	9,563	21.3%
	Diesel	36	0.6%	144	0.4%	104	212	0.5%
	Hydroelectric	1,750	29.2%	2,029	6.3%	1,001	3,030	6.7%
	Nuclear	0	0.0%	8,464	26.1%	183	8,647	19.2%
	Steam	3,593	59.9%	7,244	22.4%	730	4,381	9.7%
	Wind	0	0.0%	8	0.0%	2,916	2,924	6.5%
	Unknown	0	0.0%	0	0.0%	30	30	0.1%
	EMAAC Total	5,999	100.0%	32,381	100.0%	16,847	44,979	100.0%
Non-MAAC	Combined cycle	0	0.0%	9,978	9.4%	7,248	17,226	12.0%
	Combustion turbine	27	0.1%	14,028	13.2%	3,203	17,204	11.9%
	Diesel	39	0.2%	198	0.2%	309	468	0.3%
	Hydroelectric	1,338	6.3%	4,412	4.1%	540	4,952	3.4%
	Nuclear	0	0.0%	18,630	17.5%	2,401	21,031	14.6%
	Steam	19,956	93.4%	58,303	54.8%	6,270	44,617	31.0%
	Wind	0	0.0%	815	0.8%	37,545	38,360	26.6%
	Unknown	0	0.0%	0	0.0%	213	213	0.1%
	Non-MAAC Total	21,360	100.0%	106,365	100.0%	57,729	144,072	100.0%
SWMAAC	Combined cycle	0	0.0%	1,134	8.9%	1,295	2,429	18.2%
	Combustion turbine	59	2.0%	2,189	17.2%	574	2,704	20.3%
	Diesel	0	0.0%	0	0.0%	8	8	0.1%
	Hydroelectric	0	0.0%	0	0.0%	0	0	0.0%
	Nuclear	0	0.0%	1,735	13.6%	1,640	3,375	25.3%
	Steam	2,868	98.0%	7,678	60.3%	0	4,810	36.0%
	Wind	0	0.0%	0	0.0%	0	0	0.0%
	Unknown	0	0.0%	0	0.0%	20	20	0.1%
	SWMAAC Total	2,927	100.0%	12,736	100.0%	3,537	13,346	100.0%
WMAAC	Combined cycle	0	0.0%	3,044	13.9%	5,431	8,475	27.2%
	Combustion turbine	198	5.1%	1,211	5.5%	1,305	2,318	7.4%
	Diesel	20	0.5%	69	0.3%	78	127	0.4%
	Hydroelectric	443	11.5%	1,082	5.0%	175	1,257	4.0%
	Nuclear	0	0.0%	3,075	14.1%	1,731	4,806	15.4%
	Steam	3,200	82.9%	13,139	60.1%	499	10,438	33.5%
	Wind	0	0.0%	232	1.1%	3,323	3,555	11.4%
	Unknown	0	0.0%	0	0.0%	153	153	0.5%
	WMAAC Total	3,861	100.0%	21,852	100.0%	12,694	31,128	100.0%
All Areas	Total	34,147		173,334		90,807	233,525	

65 Percents shown in Table 3-40 are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

Scarcity and Scarcity Pricing

A wholesale energy market will not consistently result in adequate revenues in the absence of a carefully designed and comprehensive approach to scarcity pricing. This is a result, not of offer capping, but of the fundamentals of wholesale power markets which must carry excess capacity in order to meet externally imposed reliability rules.

Scarcity revenues to generation owners can come entirely from energy markets or they can come from a combination of energy and capacity markets. The RPM capacity market design reflects the recognition that the energy markets, by themselves and in the absence of a carefully designed expansion of scarcity pricing, will not result in adequate revenues. The RPM design provides an alternate method for collecting scarcity revenues.

The revenues in the capacity market are scarcity revenues. If the revenues collected in the RPM market are adequate, it is not essential that a scarcity pricing mechanism exist in the energy market. Nonetheless, it would be preferable to have a scarcity pricing mechanism in the energy market because it provides direct, market-based incentives to load and generation, as long as the market rules are designed to ensure that scarcity revenues directly offset RPM revenues to prevent double collection of scarcity revenues.

The energy market can and should be competitive. A competitive market clears based on the marginal cost of the highest cost unit that is producing energy, accounting for the possibility of multiple marginal units in the presence of transmission constraints. There is no reason to build market power into the design of the energy markets. A complete market design will provide adequate revenues via scarcity revenues in an energy only market or via scarcity revenues provided in the form of capacity payments in a hybrid market design.

A hybrid market design can provide scarcity revenues both via scarcity pricing in the energy market and via the capacity market. However, if scarcity revenues are provided in the energy market, there must be an explicit mechanism to remove those revenues from capacity market revenues. This offset must reflect the actual scarcity revenues and not those reflected in forward curves or forecast by analysts from any organization. The absence of such a mechanism is likely to result in an over collection of scarcity revenues as such revenues are episodic and unlikely to be fully reflected in forward curves, even if such curves were based on a liquid market three years forward and reflected locational results, which they do not. The most straightforward way to ensure that such over collection does not occur would be to ensure that capacity resources do not receive scarcity revenues in the energy market in the first place. The settlements process can remove any scarcity revenues from payments to capacity resources and eliminate the need for a complex, uncertain, after the fact procedure for offsetting scarcity revenues in the capacity market.

In 2005, prior to the introduction of the RPM capacity market design, it was recognized that changing market dynamics created by PJM's expanded footprint, along with PJM's continued need for non market emergency mechanisms to maintain system reliability under conditions of scarcity, had created a need for an administrative scarcity pricing mechanism.[66] The scarcity pricing settlement

66 See the *2005 State of the Market Report*, "Scarcity" (March 8, 2006), pp. 145-150.

was an effort to address the revenue adequacy and incentive issues in PJM markets in the absence of a capacity market design that reflected the full costs of capacity.

PJM members entered into a settlement in 2005 that was approved by the FERC and resulted in the implementation of administrative scarcity pricing rules in 2006.[67] August 8, 2007, was the first time that the administrative scarcity pricing rules were triggered. PJM did not declare a scarcity pricing event in 2008.

PJM's current administrative scarcity pricing mechanism was designed to provide an appropriate tradeoff between limiting local market power and allowing market prices to reflect scarcity conditions in the absence of the RPM capacity market design.[68] The administrative rules initiate scarcity pricing when PJM takes specific, non market, emergency administrative actions to maintain system reliability under conditions of high load in defined areas within PJM. These emergency actions include emergency energy purchase request events, maximum emergency generation events, manual load dump events and voltage reduction events. When PJM implements any of the identified emergency procedures, offer capping of units in the affected area is lifted and the LMP of the entire affected area is set equal to the highest-priced offer of a unit dispatched at the time.

PJM's current scarcity pricing rules have been invoked only once. These rules have not and will not have a significant impact on generator revenues. However, that is irrelevant given the development of the RPM capacity market design. With a properly defined revenue offset, the introduction of improved scarcity pricing measures in PJM markets will affect the incentives of a very limited set of PJM resources. Scarcity pricing will generally not affect the incentives of either generation or load that has committed in the Day-Ahead Energy Market. Scarcity pricing will affect the incentives of load at the margin on high load days. Scarcity pricing will affect the incentives of external resources to sell power to PJM markets. Scarcity pricing will affect the incentives of DSR providers and users at the margin. Modifications to scarcity pricing will improve the functioning of PJM markets but they will, if properly designed, not have a large impact on revenues for most generators or charges for most loads.

Scarcity Pricing Issues

Scarcity exists when the total demand for power approaches the generating capability of the system. Scarcity pricing means that market prices reflect the fact that the system is close to its available capacity. Under scarcity conditions, competitive prices may exceed short-run marginal costs. Under the current PJM rules, high prices result from high offers by individual generation owners for specific units when the system is close to its available capacity. These offers give the aggregate energy supply curve its steep upward sloping tail.[69] As demand increases and units with higher offers are required to meet demand, prices increase. This dynamic may be limited if all units with high offers are subject to offer capping for local market power. In that case, an explicit decision to lift offer capping must be based on a determination that scarcity exists in a defined area. Under the scarcity pricing provisions in the tariff, that determination is made when PJM takes identified

67 114 FERC ¶ 61,076 (2006).
68 114 FERC ¶ 61,076 (2006).
69 See the *2008 State of the Market Report*, Volume II, Section 2. at "Market Structure."

emergency actions. Scarcity pricing results, with the scarcity price based on the highest offer of an operating unit.

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 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 in well-defined stages with transparent triggers and 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. With a capacity market design that appropriately reflects scarcity rents in the energy market as an offset to capacity market offers, 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.

The challenge is to translate these basic guidelines about scarcity pricing into a consistent set of market rules. The MMU recommendations regarding scarcity pricing represent a step toward defining market rules.

While PJM's triggers for administrative scarcity pricing are reasonable measures of scarcity conditions, there are indications, based on the MMU analysis of 2007 market results, that PJM's current set of scarcity pricing rules need refinement.[70] While PJM did declare a scarcity pricing event in 2007, prior to that declaration PJM was able to use emergency resources to meet operational goals, declaring a maximum emergency alert, which resulted in the inclusion of maximum emergency generation resources in operational reserve and the calling of emergency demand-response resources, without triggering a scarcity event. Had the use of emergency demand-response resources been a trigger, the scarcity event would have started earlier and ended later than it did in 2007.

It is also not clear that a reliance on emergency steps as a trigger for scarcity, and the simple removal of offer caps based on that trigger, is the most effective and efficient way to recognize and reflect scarcity in a least cost, security constrained dispatch based market.

Definitions and Methodology

Scarcity can be defined to exist when demand, including an operating reserve target, is greater than, or equal to, available supply excluding the impact of non market administrative intervention. Scarcity can exist at varying levels of severity, reflected by the degree to which load plus the reserve requirement exceeds supply, excluding the impact of non market administrative actions. The more emergency resources and actions that are needed to maintain system reliability, the more severe the scarcity event.

70 PJM did not declare a scarcity event in 2008.

Relevant operating reserve targets are an essential component of the definition of scarcity. Operating reserve targets are currently calculated based on the sum of control-zone-specific, 30-minute, day-ahead reserve requirements as defined by PJM.[71]

Operating reserve targets are designed to inform system operators of the resources, in excess of expected peak system requirements, required to maintain reliability during the peak hours. These reserves are not required during off peak hours and system operators may not always maintain the defined level of reserves during high load periods.

For purposes of defining trigger points for scarcity events, the reserve requirements and available resource measures should be defined in a way that is consistent with the nature of system operations. Operating reserve targets should be dynamic, based on current operating conditions and defined for predefined scarcity pricing regions. This is consistent with PJM's current scarcity pricing zones which are defined based on distribution factors to specific constraints.

Using a more dynamic and precise measure of operating reserves requirements, scarcity can be defined to exist when within half hour demand, including a operating reserve target, is greater than, or equal to, total, within-half hour supply excluding the impact of non market administrative intervention. Scarcity can exist at varying levels of severity, reflected by the degree to which the relevant reserve requirement exceeds within-half hour supply, excluding the impact of non market administrative actions. The more emergency resources and actions that are needed to maintain system reliability, the more severe the scarcity event.

Non market, administrative tools available to PJM to ensure that demand does not exceed supply include calling for full emergency load response, recalls of noncapacity-backed exports, loading of maximum emergency generation, voltage reductions, emergency power purchases and manual load dump.[72] Of these steps, the last four are defined in the PJM Tariff as triggers for scarcity pricing events.[73] The use of any of these measures to maintain system integrity in predefined scarcity pricing regions should provide an indication that the affected area of the system is in a state of scarcity.

Four emergency messages trigger administrative scarcity pricing under the PJM Tariff. (See Table 3-41.)[74, 75]

71 See PJM. "Manual 10: Pre-Scheduling Operations," Revision 20 (Effective June 15, 2006), pp. 21-25. See also PJM. "Manual 11: Scheduling Operations," Revision 29 (Effective August 11, 2006), pp. 87-96.

72 See PJM. "Manual 13: Emergency Operations," Revision: 27 (Effective September 5, 2006), p. 29: "The PJM RTO is normally loaded according to bid prices; however, during periods of reserve deficiencies, other measures must be taken to maintain reliability."

73 See PJM. "Open Access Transmission Tariff (OATT)," Sixth Revised Volume No. 1, Third Revised Sheet No. 402A.01 (Effective January 27, 2006).

74 "Maximum emergency generation loaded" covers the first three trigger events: a) Begin to dispatch online generators, which are partially designated as maximum emergency, into emergency output levels; b) Begin to dispatch online generators, which are designated entirely as maximum emergency, above their designated minimum load points, if they are currently online and operating at their minimum load points because of restrictive operating parameters associated with the generators; and c) Begin to dispatch any offline generators that are designated entirely as maximum emergency and that have start times plus notification times less than or equal to 30 minutes.

75 114 FERC ¶ 61,076 (2006).

Table 3-41 Scarcity-related emergency messages

Emergency Message	Description
Max emergency gen loaded	The purpose is to increase generation above the normal economic limit.
Voltage reduction	A request to reduce distribution level voltage by 5%, which provides load relief.
Emergency energy purchase	This is a request by PJM for emergency purchases of energy. PJM will select which offers are accepted based on price and expected duration of the need. This request is typically issued at the Max Emergency Generation emergency procedure step.
Manual load dump	The request to disconnect firm customer load (rotating blackouts). This is issued when additional load relief is needed and all other possible procedures have been exhausted. Target: Electricity Distribution Companies

Current Issues with Scarcity Implementation

There is a choice between using market signals and administrative actions to maintain the balance between supply and demand when the market is tight. Reliance on administrative actions means that there is no clear, price based signal that the system requires the use of emergency resources. In the short run, prices that reflect the shortage of resources signal the need for resources and may result in immediate responses on the supply and demand sides. In the long run, prices provide signals regarding the need for additional generation, demand-response and transmission resources in the scarcity regions.

Reliance on the use of emergency administrative steps to indicate scarcity means that the system is in a condition of scarcity prior to it being declared under the current rules. The current administrative scarcity pricing rules result in a non-locational signal within the scarcity pricing regions. Under the current rules, a scarcity pricing event sets prices for all generators in the defined area at the same level, equal to the highest accepted offer within a scarcity pricing region. This provides a signal that is inconsistent with economic dispatch and inconsistent with locational pricing. Further, the scarcity price signal under the current rules will not necessarily reflect the severity of the scarcity event, as the price level in a scarcity event does not reflect the severity of the shortage or the types of emergency actions taken to maintain system integrity during the scarcity event.

This suggests that the administrative definition of scarcity should include several stages of scarcity, each with an associated administrative price, rather than the single step now in the Tariff. Further, scarcity pricing should be nodal in nature. Nodal scarcity price signals would provide signals consistent with economic dispatch and locational pricing during the event

Proposed Scarcity Pricing Approach

The MMU recommends that the current scarcity rule, as provided in the PJM Tariff, be reviewed and enhanced to ensure competitive prices by introducing:

- **Locational Price Signals.** The current single scarcity price signal should be replaced by locational signals. Locational scarcity signals could be implemented via reserve requirements modeled as constraints for scarcity regions, with administrative scarcity penalty factors, in the security constrained dispatch. The level of the penalty factor and the reserve target would be determined by the severity level of the scarcity event. This would provide a means to signal scarcity that is consistent with economic dispatch, consistent with locational pricing and consistent with competitive market outcomes.

- **Stages of Scarcity Pricing.** Administrative scarcity pricing should include stages, based on system conditions, with progressive impacts on prices. The trigger for each stage should be based on the level of available operating reserve using a dynamically determined and relevant operating reserve requirement and the progressive use of emergency measures. Implemented as scarcity region specific operating reserve constraints in the security constrained dispatch, the severity of scarcity event should be reflected in a set of increasing, administrative penalty factors.

  The level of operating reserves results in PJM implementing emergency measures. The level of the penalty factor would be a function of both the level of operating reserves and the number and nature of emergency administrative steps taken to maintain system integrity. For example, the initial penalty factor associated with the violating the operating reserve constraint could come into play whenever there were insufficient operating reserves to meet the operating reserve constraint in a given thirty minute period. Subsequent escalation of the scarcity condition would be reflected in the system and in prices by tightening the reserve requirement constraint and increasing the penalty factor associated with the reserve requirement constraint, with each emergency measure taken in a defined scarcity pricing region. So the calling of a maximum emergency generation alert that allows maximum emergency capacity to be counted toward operating reserve requirements, the calling of emergency demand response, the recall of non capacity-backed exports, the loading of maximum emergency generation, voltage reductions, emergency power purchases and manual load dumps in one or more contiguous transmission zones could all cause an increase in the penalty factor. The increase in the reserve requirement constraint with emergency actions would offset the effect of the administrative step in reducing demand or expanding supply beyond economic levels.

- **Offer capping.** If implemented using reserve requirement constraints with escalating penalty factors, the scarcity pricing mechanism would eliminate the need to lift offer capping during a scarcity pricing event. Properly set, the penalty factors would increase prices on the system to provide a locational pricing signal reflecting the severity of the shortage. This approach also eliminates the incentive for participants to make non-competitive energy offers in anticipation of scarcity events. Keeping offers consistent during the event would have the added benefit of avoiding the operational issues involved with sudden changes in the economic dispatch order before, during and after a scarcity event.

Operating Reserve

Day-ahead and real-time operating reserve credits are paid to generation owners under specified conditions in order to ensure that units are not required to operate for the PJM system at a loss. Sometimes referred to as uplift or revenue requirement make whole, these payments are intended to be one of the incentives to generation owners to offer their energy to the PJM Energy Market at marginal cost and to operate their units at the direction of PJM dispatchers. These credits are paid by PJM market participants as operating reserve charges.

From the perspective of those participants paying operating reserve charges, these costs are an unpredictable and unhedgeable component of the total cost of energy in PJM. While reasonable operating reserve charges are an appropriate part of the cost of energy, market efficiency would be improved by ensuring that the level of operating reserve charges is as low as possible consistent with the reliable operation of the system and that the allocation of operating reserve charges reflects the reasons that the costs are incurred.

The level of operating reserve credits and corresponding charges decreased in 2008 by 6.5 percent compared to 2007. This was the result of a large decrease in the amount of synchronous condensing operating reserve credits, a smaller decrease in the amount of balancing operating reserve credits and an increase in the amount of day-ahead operating reserve credits.

The level of operating reserve credits paid to specific units depends on the level of the unit's energy offer, the unit's operating parameters as well as the decisions of PJM operators. Operating reserve credits result in part from decisions by PJM operators, who follow reliability requirements and market rules, to start units or to keep units operating even when hourly LMP is less than the offer price including energy, startup and no-load offers. PJM continues internal processes to review and measure daily operating reserve performance, to analyze issues and resolve them in a timely manner, to make better information more readily available to dispatchers and to emphasize the impact of dispatcher decisions on operating reserve charge levels.

The MMU has previously concluded that some modifications to PJM rules governing operating reserve credits to generators would be appropriate. Such modifications should aim to ensure that credits paid to market participants and corresponding charges paid by market participants are consistent with incentives for efficient market outcomes and to eliminate gaming incentives and the ability to exercise market power. Such modifications should address both the level of and the appropriate allocation of operating reserve charges, accounting where appropriate and possible for causal factors including location. The new operating reserve rules represent positive steps towards these goals.

On November 15, 2007, after a lengthy membership process, the PJM Members Committee (MC) approved proposed revisions to Schedule 1 of the PJM Operating Agreement and to the operating reserve business rules to enhance the efficiency of the operating reserve process by modifying the rules governing balancing operating reserves. PJM filed these changes with the Commission on September 24, 2008. PJM explained to the FERC that it delayed filing, "in order to synchronize the timing of this filing to occur after the completion of the development of the required technical and billing software changes to PJM's MSET system, which … did not occur until August 1, 2008."[76] The Commission approved PJM's filing, which became effective on December 1, 2008, but required that PJM make a compliance filing to incorporate specified business rules in the tariff.[77]

PJM submitted its compliance filing on December 24, 2008, but, in addition to the business rules that the Commission specified, also included rules related to parameter limited schedules. The compliance filing went beyond the simple steps needed for compliance and included additional revisions that differed from the rules filed by PJM and agreed to by the stakeholders. Approval of these proposed additional revisions would undermine PJM's market power mitigation as it applies

76 PJM transmittal letter in Docket No. ER08-1569-000 at 2 (September 24, 2008).
77 PJM Interconnection, L.L.C., 125 FERC ¶ 61,244 at P 40 (2008).

to operating parameter limits. On January 21, 2009, the MMU filed a protest with the FERC raising both procedural and substantive objections to PJM's approach for compliance.[78] PJM and others filed responses on February 5 and 6, 2009, and the MMU filed a response on February 17, 2009.[79] At this time, a decision from the Commission is pending.

New rules governing the payment of operating reserves credits and the allocation of operating reserves charges became effective on December 1, 2008. The new Operating Reserve Construct will be referenced as the new rules and the prior Operating Reserve Construct will be referred to as the old rules.

PJM's December 1 filing included the following salient changes to the operating reserve business rules:

- **Segmented Make-Whole Payments.** Resources will be made whole separately for the blocks of hours they operate at PJM direction. There will a maximum of two segments per calendar day, per unit. The first segment will be the greater of the day-ahead schedule or minimum run time (minimum downtime for demand resources); the second segment will be the remainder of the unit run for that calendar day.[80]

- **Parameter-Limited Schedules.** When a unit needed for operating reserve has local market power as defined by the three pivotal supplier test, units will be required to use operating parameters consistent with competitive offers. These parameters are defined by unit characteristics and included in a matrix posted by the MMU. PJM also developed business rules approved November 15, 2007, by the Members Committee that, among other things, established a process to evaluate unit-specific exceptions to the values included in the matrix.[81]

- **Generator Deviations.** PJM will use ramp-limited desired MW to determine generator deviations from desired dispatch. Pool-scheduled generators deemed to be following dispatch will not be assessed balancing operating reserve deviations.[82]

- **Netting Generator Deviations.** Generators that deviate from real-time dispatch will be able to offset deviations by using another generator at the same bus. Both generators must be owned or offered by a single PJM market participant and must have identical electrical impacts on the transmission system.[83]

- **Locational Netting of Deviation Calculations.** Demand deviations will be calculated by comparing all day-ahead demand transactions within a single transmission zone, hub, or interface against the real time demand transactions within that same transmission zone, hub,

78 Protest of the Independent Market Monitor for PJM filed in Docket No. ER08-1569-001. The Market Monitor posts a copy of this document on its Website at: <http://www.monitoringanalytics.com/reports/Reports/2009/IMM%20Protest%20re%20Operating%20Reserves%20ER08-1569.pdf>.

79 See, e.g., Motion for Leave to Answer and Answer of PJM Interconnection, L.L.C. to the Protest of the Independent Market Monitor for PJM filed in Docket No. ER08-1569-001. PJM posts this on its Website at <http://www.pjm.com/Media/documents/ferc/2009-filings/20090206-er08-1569-000.pdf>; Motion for Leave to Answer and Answer of the Independent Market Monitor for PJM filed in Docket No. ER08-1569-001 (February 6, 2009). The Market Monitor posts this on its Website at: <http://www.monitoringanalytics.com/Reports/2009/IMM%20Answer%20to%20Answers%20ER08-1569.pdf>.

80 PJM "Operating Reserve Revised Business Rules v6": Segmented Make Whole Payments at <<http://www.pjm.com/markets-and-operations/energy/~/media/markets-ops/energy/op-reserves/operating-reserve-revised-business-rules-v6.ashx>.

81 PJM "Operating Reserve Revised Business Rules v6": Minimum Generator Operating Parameters – Parameter Limited Schedule at <<http://www.pjm.com/markets-and-operations/energy/~/media/markets-ops/energy/op-reserves/operating-reserve-revised-business-rules-v6.ashx>.

82 PJM "Operating Reserve Revised Business Rules v6": Ramp-limited RT Desired MW to determine deviations at <<http://www.pjm.com/markets-and-operations/energy/~/media/markets-ops/energy/op-reserves/operating-reserve-revised-business-rules-v6.ashx>.

83 PJM "Operating Reserve Revised Business Rules v6": Supplier Netting at <<http://www.pjm.com/markets-and-operations/energy/~/media/markets-ops/energy/op-reserves/operating-reserve-revised-business-rules-v6.ashx>.

or interface. Supply deviations will be calculated by comparing all day-ahead transactions within a single transmission zone, hub, or interface against the real time transactions within that same transmission zone, hub, or interface. Generator deviations will be calculated on a unit-specific basis, except for the netting provisions. Deviations that occur within a single zone will be associated with a region and will be charged the regional balancing operating reserve rate.[84]

- **Balancing Operating Reserve Charge Allocation.** PJM will determine whether operating reserve credits are earned for reasons associated with reliability or with real-time deviations from day-ahead results. PJM will make this determination in both the reliability analysis stage and the real-time stage. Reliability related credits are allocated to be recovered from charges to real-time load plus exports and deviations related credits are allocated to be recovered from charges to deviations.[85]

- **Regional Balancing Operating Reserve Charge Allocation.** PJM will identify operating reserves credits that are associated with controlling local constraints, identified as constraints on transmission lines rated at less than or equal to 345kv. Local constraints will be identified as in the Western or the Eastern Region. The resultant operating reserve credits will be allocated as charges to all real-time deviations and real time load within a region, resulting in a Regional Adder rate for Reliability and a Regional Adder rate for Deviations.[86]

Credit and Charge Categories

Operating reserve credits include day-ahead, synchronous condensing and balancing operating reserve categories**.** Total operating reserve credits paid to PJM participants equal the total operating reserve charges paid by PJM participants. Table 3-42 shows the categories of credits and charges and their relationship. The bottom half of this table also shows how credits are allocated under the new operating reserve construct. Table 3-43 shows the different types of deviations.

84 PJM "Operating Reserve Revised Business Rules v6": Netting Deviation Calculations at <http://www.pjm.com/markets-and-operations/energy/~/media/markets-ops/energy/op-reserves/operating-reserve-revised-business-rules-v6.ashx>.

85 PJM "Operating Reserve Revised Business Rules v6": Balancing Operating Reserve Cost Allocation at <http://www.pjm.com/markets-and-operations/energy/~/media/markets-ops/energy/op-reserves/operating-reserve-revised-business-rules-v6.ashx>.

86 PJM "Operating Reserve Revised Business Rules v6": Regional Balancing Operating Reserve Charge Allocation at <http://www.pjm.com/markets-and-operations/energy/~/media/markets-ops/energy/op-reserves/operating-reserve-revised-business-rules-v6.ashx>.

Table 3-42 Operating reserve credits and charges

Credits Received		Charges Paid
Day ahead:		Day-ahead demand
Day-Ahead Energy Market	→	Decrement bids
Day-ahead import transactions		Day-ahead export transactions
Synchronous condensing		Real-time load
	→	Real-time export transactions
Balancing:		
Balancing energy market		Real-time deviations
Lost opportunity cost	→	from day-ahead schedules
Real-time import transactions		
Balancing Energy Market Credits Received		**Balancing Energy Market Charges Paid**
Reliability Analysis (RTO, East, West)		Real-time load
Reliability Credits	→	Real-time export transactions
Deviation Credits	→	Real-time deviations
		from day-ahead schedules
Real-Time Market (RTO, East, West)		Real-time load
Reliability Credits	→	Real-time export transactions
Deviation Credits	→	Real-time deviations
		from day-ahead schedules

Table 3-43 Operating reserve deviations

Deviations		
Day ahead		Real time
Day-ahead decrement bids	Demand (Withdrawal)	Real-time load
Day-ahead load	(RTO, East, West)	Real-time sales
Day-ahead sales		Real-time export transactions
Day-ahead export transactions		
Day-ahead increment offers	Supply (Injection)	Real-time purchases
Day-ahead purchases	(RTO, East, West)	Real-time import transactions
Day-ahead import transactions		
Day-ahead scheduled generation	Generator (Unit)	Real-time generation

Day-Ahead Credits and Charges

Day-ahead operating reserve credits consist of Day-Ahead Energy Market and day-ahead import transaction credits. The rules governing these credits and associated charges were not modified in the new rules.

The day-ahead operating reserve charges that result from paying total day-ahead operating reserve credits are allocated daily to PJM members in proportion to the sum of their cleared day-ahead demand, decrement bids and day-ahead exports. Table 3-45 shows monthly day-ahead operating reserve charges for calendar years 2007 and 2008.

Synchronous Condensing Credits and Charges

Synchronous condensing credits are provided to eligible synchronous condensers for real-time condensing and energy use costs if PJM dispatches them for purposes other than synchronized reserve, post-contingency constraint control or reactive services.[87] The rules governing these credits and associated charges were not modified in the new rules.

The operating reserve charges that result from paying operating reserve credits for synchronous condensing are allocated daily to PJM members in proportion to the sum of their real-time load and real-time export transactions. Table 3-45 shows monthly synchronous condensing charges for calendar years 2007 and 2008.

Balancing Credits and Charges

Balancing operating reserve credits consist of balancing energy market credits, lost opportunity cost credits, and real-time import transaction credits. Balancing operating reserve credits are paid to generation resources that operate at PJM's request if market revenues are less than the resource's offer. Lost opportunity cost credits are paid to generation resources when their output is reduced by PJM for reliability purposes from their economic or self-scheduled output level. Balancing operating reserve credits are paid to real-time import transactions, if market revenues are less than the offer. Balancing operating reserve credits are also paid to cancelled pool-scheduled resources, to resources providing quick start reserve and to resources performing annual, scheduled black start tests.

Under the old rules, operating reserve charges that result from paying balancing operating reserve credits are allocated daily to PJM members in proportion to their real-time hourly deviations from cleared quantities in the Day-Ahead Market. Table 3-45 shows monthly balancing operating reserve charges for calendar years 2007 and 2008. Under the new rules, only credits identified as related to deviations are allocated to deviations. Credits identified for reliability purposes are allocated to real-time load plus exports. Deviations fall into three categories, demand, supply and generator deviations, and are calculated on an hourly net basis. Each type of deviation is calculated separately and a PJM member may have deviations in all three categories.

87 PJM. "Manual 28: Operating Agreement Accounting," Revision 39 (January 1, 2008).

- **Demand.** Hourly deviations in the demand category equal the absolute value of the difference between: a) the sum of cleared decrement bids plus cleared, day-ahead load plus day-ahead exports scheduled through the Enhanced Energy Scheduler (EES);[88] and b) the sum of real-time load plus real-time sales scheduled through eSchedules[89] plus real-time exports scheduled through the EES. Under the old rules, demand deviations were calculated over the entire RTO. Under the new rules, deviations are calculated within a single transmission zone, hub, or interface.

- **Supply.** Hourly deviations in the supply category equal the absolute value of the difference between: a) the sum of the cleared increment offers plus day-ahead imports scheduled through EES; and b) the sum of the real-time bilateral transactions scheduled through eSchedules plus real-time imports scheduled through EES. Under the old rules, demand deviations were calculated over the entire RTO. Under the new rules, deviations are calculated within a single transmission zone, hub, or interface.

- **Generator.** Hourly deviations in the generator category equal the absolute value of the difference between: a) a unit's cleared, day-ahead generation; and b) a unit's hourly, integrated real-time generation. More specifically, a unit has calculated deviations for an hour if the hourly integrated real-time output is not within 5 percent of the hourly day-ahead schedule; the hourly integrated real-time output is not within 10 percent of the hourly integrated desired output; or the unit is not eligible to set LMP for at least one five-minute interval during an hour. Deviations continue to be calculated for individual units, except where netting at a bus is permitted.

Credit and Charge Results

Overall Results

Table 3-44 shows total operating reserve credits from 1999 through 2008, a period when significant market changes occurred.[90, 91] Total operating reserve credits decreased by 6.5 percent in 2008. Table 3-44 shows the ratio of total operating reserve credits to the total value of PJM billings.[92] This ratio decreased from 1.5 percent in 2007 to 1.3 in 2008. The ratio in 2008 is the lowest it has been since 1999. The overall results for 2008 are presented for December in a manner consistent with the calculations under the old rules to permit comparisons. The December charges are also shown in the categories defined under the new rules.

88 The Enhanced Energy Scheduler is a PJM application used by participants to schedule import and export transactions.

89 PJM's eSchedules is an application used by participants for internal bilateral transactions.

90 Table 3-44 includes all categories of credits as defined in Table 3-42 and includes all PJM Settlements billing adjustments. Billing data can be modified by PJM Settlements at any time to reflect changes in the evaluation of operating reserves. The billing data reflected in this report were the current figures on February 26th, 2008.

91 An Energy Market that clears based on market-based generator offers was initiated on April 1, 1999. The 1999 total includes Energy Market operating reserve credits for three months based on generators' cost-based offers and for nine months based on generators' market-based offers. The Day-Ahead Energy Market opened on June 1, 2000. Operating reserve credits for 1999 and the first five months of 2000 include only those credits paid in the balancing energy market. Since June 1, 2000, operating reserve credits have included credits for both day-ahead and balancing.

92 See the *2008 State of the Market Report*, Volume II, Section 7, "Congestion," at Table 7-1, "Total annual PJM congestion (Dollars (Millions)): Calendar years 2003 to 2008," for a description of the value of total annual PJM billings during the period indicated.

Table 3-44 Total day-ahead and balancing operating reserve credits: Calendar years 1999 to 2008

	Total Operating Reserve Credits	Annual Credit Change	Operating Reserve as a Percent of Total PJM Billing	Day-Ahead $/MWh	Day-Ahead Change	Balancing $/MWh	Balancing Change
1999	$133,897,428	NA	7.5.%	NA	NA	NA	NA
2000	$216,985,147	62.1%	9.6%	0.3412	NA	0.5346	NA
2001	$290,867,269	34.0%	8.7%	0.2746	(19.5%)	1.0700	100.2%
2002	$237,102,574	(18.5%)	5.0%	0.1635	(40.4%)	0.7873	(26.4%)
2003	$289,510,257	22.1%	4.2%	0.2261	38.2%	1.1971	52.0%
2004	$414,891,790	43.3%	4.8%	0.2300	1.7%	1.2362	3.3%
2005	$682,781,889	64.6%	3.0%	0.0762	(66.9%)	2.7580	123.1%
2006	$322,315,152	(52.8%)	1.5%	0.0781	2.6%	1.3315	(51.7%)
2007	$459,124,502	42.4%	1.5%	0.0570	(27.0%)	2.3310	75.1%
2008	$429,253,836	(6.5%)	1.3%	0.0844	48.0%	2.1132	(9.3%)

Table 3-44 shows the average operating reserve credits per MWh (or the charge rate) for each full year since the introduction of the Day-Ahead Energy Market.[93] The day-ahead operating reserve rate increased $0.0274 per MWh or 48.0 percent from $0.0570 per MWh in 2007 to $0.0844 per MWh in 2008. The balancing operating reserve rate decreased $0.2178 per MWh, or 9.3 percent, from $2.3310 per MWh in 2007 to $2.1132 per MWh in 2008.

Table 3-45 compares monthly operating reserve charges by category for calendar years 2007 and 2008. The overall decrease of 6.5 percent in 2008 is comprised of a 41.3 percent increase in day-ahead operating reserve charges, an 84.7 percent decrease in synchronous condensing charges and a 2.3 percent decrease in balancing operating reserve charges.

Total operating reserve charges in 2008 were $429,253,836, down from the total of $459,124,502 in 2007, which was primarily the result of the decrease of $31,721,586 in synchronous reserve charges. The share of day-ahead operating reserve charges to total operating reserve charges increased by 5.2 percentage points to 16.2 percent, the share of synchronous condensing charges decreased 7 percentage points to 1.3 percent, and the share of balancing charges increased 1.8 percentage points to 82.4 percent.

As of December 1, 2008, balancing charges are allocated to six separate categories. (See Table 3-47.) These categories are RTO reliability charges, East Region reliability charges, West Region reliability charges, RTO deviation charges, East Region deviation charges and West Region deviation charges. The balancing charges in Table 3-45 for December are the sum of the six categories, plus lost opportunity cost charges ($2,840,091), cancellation charges ($46,727) and all other local constraint balancing charges ($2,883).

93 In Table 3-44, "Total day-ahead and balancing operating reserve credits: Calendar years 1999 to 2008," numbers are based on data from PJM market settlements department that include manual adjustments. The data in Table 3-45, Table 3-50, Table 3-55 and Figure 3-11 are based on the PJM market settlements database and do not include manual adjustments.

Table 3-45 Monthly operating reserve charges: Calendar years 2007 and 2008

	2007			2008		
	Day-Ahead	Synchronous Condensing	Balancing	Day-Ahead	Synchronous Condensing	Balancing
Jan	$5,627,466	$2,001,215	$18,524,772	$4,126,221	$456,972	$39,935,491
Feb	$5,739,401	$2,670,396	$34,259,749	$3,731,017	$200,456	$23,165,838
Mar	$4,611,047	$1,300,459	$23,317,961	$2,904,498	$249,900	$18,916,241
Apr	$5,981,246	$1,208,114	$17,472,454	$4,213,578	$209,366	$22,559,577
May	$6,305,138	$1,584,887	$16,198,291	$10,873,205	$202,397	$22,970,363
Jun	$3,905,778	$2,706,483	$32,779,988	$7,064,877	$575,927	$65,597,311
Jul	$2,221,518	$4,374,349	$31,682,112	$7,038,834	$874,234	$48,041,415
Aug	$1,909,243	$7,495,702	$61,410,545	$6,140,554	$143,857	$26,212,547
Sep	$2,896,590	$5,046,901	$42,197,260	$4,581,147	$405,308	$27,809,898
Oct	$1,970,822	$5,024,503	$29,581,616	$6,705,261	$794,271	$16,054,255
Nov	$3,715,092	$3,332,124	$21,265,389	$5,069,462	$635,697	$21,097,016
Dec	$4,404,038	$721,130	$33,454,922	$7,175,436	$996,292	$21,525,117
Total	$49,287,379	$37,466,264	$362,145,059	$69,624,091	$5,744,678	$353,885,070
Share of Annual Charges	11.0%	8.3%	80.7%	16.2%	1.3%	82.4%

Deviations

Under the old operating reserve construct, balancing operating reserve charges were assigned to total real-time deviations from day-ahead schedules. Under the new rules, only a subset of defined balancing reserve charges are assigned to deviations and deviations are separated into RTO and regional categories. Table 3-46 shows monthly real-time deviations for demand, supply and generator categories for 2007 and 2008. Total deviations summed across the demand, supply, and generator categories were higher in 2008 than 2007. From 2007 to 2008, the share of total deviations in the demand category decreased by .8 percentage points, in the supply category increased by 4.0 percentage points and in the generator category decreased by .6 percentage points.

As of December 1, 2008, new rules governing the calculation of generator deviations were implemented. Under the old rules, a generator was considered to deviate if the unit was operating at an actual output that was more than 10 percent from the PJM desired MW, or if they were operating at an output that was 5 percent, or 5 MW from their day-ahead schedule. Under the new rules, the ramp limited desired (RLD) MW is used instead to determine the unit's desired MW. This RLD MW is the achievable MW based on the UDS ramp rate.

Under the new rules, credits related to deviations and reliability are assigned to the RTO or to the Eastern or Western Region as shown in Table 3-47. For each region, credits related to reliability are allocated to real-time load plus exports, while credits related to deviations are allocated to real-time deviations. The deviations shown for December in Table 3-46 are the sum of deviations for all the regions.

Table 3-46 Monthly balancing operating reserve deviations (MWh): Calendar years 2007 and 2008

	2007 Deviations			2008 Deviations		
	Demand (MWh)	Supply (MWh)	Generator (MWh)	Demand (MWh)	Supply (MWh)	Generator (MWh)
Jan	7,514,621	2,906,334	2,340,413	8,172,164	3,297,121	2,572,113
Feb	6,233,800	2,962,485	2,243,011	6,728,062	3,046,290	2,546,510
Mar	6,358,269	2,550,649	2,376,102	6,392,821	2,520,387	2,405,061
Apr	6,234,452	2,491,365	2,309,824	5,951,654	3,127,726	2,224,157
May	5,835,288	2,701,154	2,574,414	6,624,696	3,787,650	2,699,616
Jun	7,893,872	3,928,908	2,570,994	8,117,669	3,179,999	2,644,016
Jul	7,976,794	3,369,275	2,646,549	9,237,956	3,914,230	2,213,828
Aug	8,302,998	3,262,800	3,301,138	8,296,485	4,000,974	2,275,294
Sep	6,743,208	2,400,749	2,189,309	7,360,536	3,691,646	2,577,095
Oct	6,418,244	2,631,321	2,352,370	6,792,603	3,538,950	2,404,069
Nov	6,249,638	2,407,343	2,156,888	6,561,634	3,586,432	2,267,083
Dec	7,018,333	2,896,010	2,805,085	8,399,099	4,898,506	1,775,964
Total	82,779,517	34,508,392	29,866,097	88,635,377	42,589,911	28,604,806
Share of Annual Deviations	56.3%	22.6%	18.5%	55.5%	26.6%	17.9%

Balancing Operating Reserve Charge Rate

The balancing operating reserve rate equals the balancing operating reserve credits divided by the sum of demand, supply and generator deviations. It is calculated on a daily basis. Until December 1, 2008, this was a single rate applied across the entire PJM footprint. Under the new rules, there are six separate rates. Figure 3-10 shows the monthly average balancing operating reserve rates for the past five years. In 2008, the average daily balancing operating reserve rate decreased to $2.1132 per MWh, which was lower than 2007 by $.2178 per MWh. For comparison purposes, the dashed line segment in Figure 3-10 shows the balancing charge rate for December 2008, calculated under the old rules. Table 3-47 shows the actual December averages for each regional rate.

Figure 3-10 Monthly average balancing operating reserve rate: Calendar years 2004 to 2008

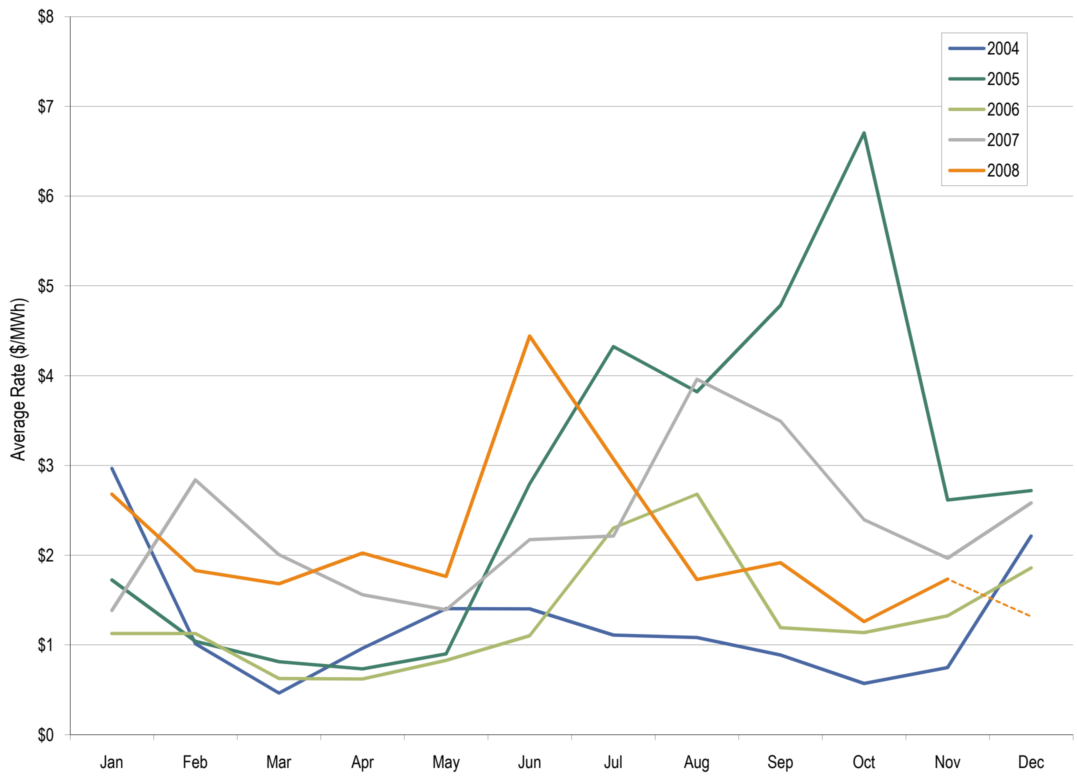


Table 3-47 Credits, deviations, rates, and charges by cost allocation category: Calendar month December 2008

	RTO Reliability	East Reliability	West Reliability	RTO Deviations	East Deviations	West Deviations
Credits ($)	$1,185,277	$24,194	$766,090	$15,989,374	$641,366	$29,114
RT Load and Exports (MWh)	63,904,484	34,102,518	29,801,966	(n/a)	(n/a)	(n/a)
Deviations (MWh)	(n/a)	(n/a)	(n/a)	15,757,287	8,922,102	6,736,430
Rates ($/MWh)	0.018	0.001	0.029	0.956	0.068	0.005
Charges ($)	$1,185,277	$24,194	$766,090	$15,989,374	$641,366	$29,114

Table 3-48 shows the total balancing reserve rate paid in each region. The East Region rate is the sum of the rates for RTO reliability charges, RTO deviation charges, East Region reliability charges and East Region deviation charges. The West Region rate is the sum of the rates for RTO reliability charges, RTO deviation charges, West Region reliability charges and West Region deviation charges. The total balancing rate for December in PJM was $1.3121 per MWh.

Table 3-48 Regional balancing operating reserve rates: December 2008

	Reliability	Deviation
East	0.019	1.025
West	0.047	0.961

Operating Reserve Credits by Category

Figure 3-11 shows that the largest share of total operating reserve credits, 63.3 percent, was paid to resources in the balancing energy market during 2008 and 82.5 percent of total operating reserve credits were in the balancing category, which includes the balancing energy market, real-time transactions, and lost opportunity costs. Figure 3-11 also shows that 16.2 percent of total operating reserve credits was paid to resources in the Day-Ahead Energy Market and that 16.2 percent of total operating reserve credits were in the day-ahead category, which includes the day-ahead energy market and day-ahead transactions. The remaining 1.3 percent of total credits was paid to resources in the synchronous condensing category.

Figure 3-11 Operating reserve credits: Calendar year 2008

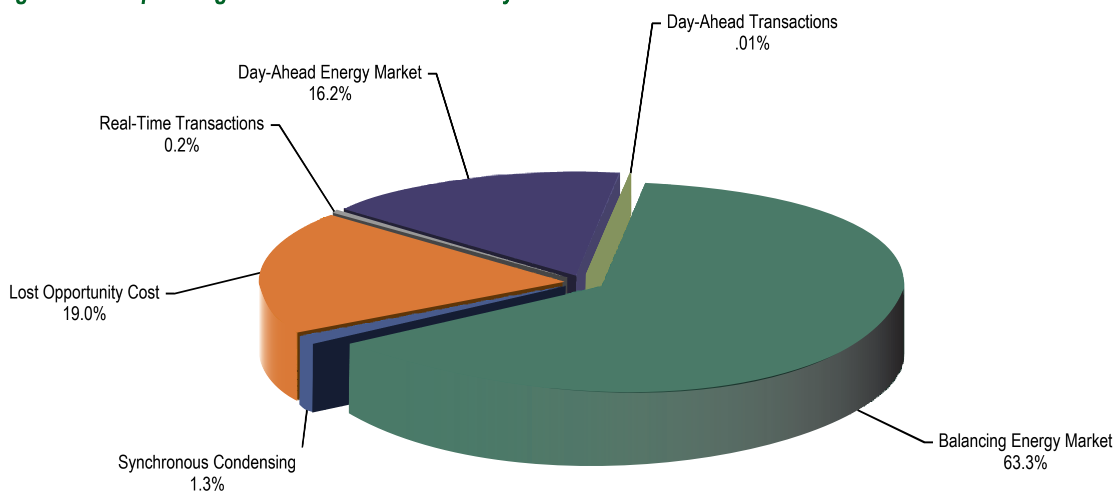


Table 3-49 shows the monthly totals for each type of credit for 2008. The highest monthly operating reserve credits were paid in June, $73,238,115, or 17.1 percent, of the total annual operating reserves. The second highest monthly operating reserve credits were paid in July, $55,954,483, or 13.0 percent, of the total annual operating reserves. June and July had the highest monthly loads in 2008. The four summer months of May, June, July, and August represented 45.6 percent of the total yearly credit share.

Table 3-49 Credits by month (By operating reserve market): Calendar year 2008

	Day-Ahead Generator	Day-Ahead Transactions	Synchronous Condensing	Balancing Generator	Real-Time Transactions	Lost Opportunity Cost	Total
Jan	$4,123,747	$2,474	$456,972	$34,597,759	$0	$5,337,732	$44,518,684
Feb	$3,731,017	$0	$200,457	$20,076,502	$0	$3,089,337	$27,097,312
Mar	$2,904,498	$0	$249,899	$15,657,684	$0	$3,258,557	$22,070,639
Apr	$4,208,697	$4,881	$209,366	$16,091,629	$0	$6,467,948	$26,982,522
May	$10,873,205	$0	$202,397	$17,518,558	$779,649	$4,672,156	$34,045,964
Jun	$7,033,102	$31,774	$575,927	$51,043,907	$0	$14,553,404	$73,238,115
Jul	$7,035,717	$3,117	$874,234	$35,016,411	$47,984	$12,977,019	$55,954,483
Aug	$6,133,170	$7,385	$143,857	$14,788,450	$0	$11,424,097	$32,496,959
Sep	$4,581,146	$0	$405,308	$20,040,461	$0	$7,769,436	$32,796,353
Oct	$6,705,260	$0	$794,271	$11,847,567	$0	$4,206,688	$23,553,787
Nov	$5,069,462	$0	$635,697	$16,259,651	$0	$4,837,365	$26,802,174
Dec	$7,175,436	$0	$996,292	$18,685,027	$0	$2,840,091	$29,696,846
Total	$69,574,458	$49,631	$5,744,678	$271,623,607	$827,633	$81,433,829	$429,253,836

Characteristics of Credits and Charges

Types of Units

Table 3-50 shows the percentage of credits received by each unit type for each type of operating reserves. (Each row sums to 100 percent.) Of the $93,476,181 in credits received by combined-cycle units, 33.1 percent were received in the day-ahead market, 63.9 percent in the balancing energy market and 3.0 percent through lost opportunity cost credits. Combustion turbines received the most operating reserve credits with $215,651,185, 76.7 percent from the balancing generator credits.

Table 3-50 Credits by unit types (By operating reserve market): Calendar year 2008

Unit Type	Day-Ahead Generator	Synchronous Condensing	Balancing Generator	Lost Opportunity Cost	Total
Combined Cycle	33.1%	0.0%	63.9%	3.0%	$93,476,181
Combustion Turbine	1.5%	2.7%	76.7%	19.1%	$215,651,185
Diesel	0.1%	0.0%	23.9%	75.9%	$4,528,081
Hydro	0.0%	0.0%	100.0%	0.0%	$440,922
Nuclear	0.0%	0.0%	0.0%	100.0%	$4,552,301
Steam	32.2%	0.0%	40.9%	26.9%	$109,712,721
Wind Farm	0.0%	0.0%	100.0%	0.0%	$15,182

Table 3-51 shows the percentage of credits for each type of operating reserves received by each unit type. (Each column sums to 100 percent.) Combined-cycle units and conventional steam units were paid 95.2 percent of the day-ahead generator credits. Combustion turbines received 100 percent of the synchronous condensing credits. Combined-cycles and combustion turbines were paid 82.9 percent of the balancing generator credits.

Table 3-51 Credits by operating reserve market (By unit type): Calendar year 2008

Unit Type	Day-Ahead Generator	Synchronous Condensing	Balancing Generator	Lost Opportunity Cost
Combined Cycle	44.5%	0.0%	22.0%	3.4%
Combustion Turbine	4.8%	100.0%	60.9%	50.5%
Diesel	0.0%	0.0%	0.4%	4.2%
Hydro	0.0%	0.0%	0.2%	0.0%
Nuclear	0.0%	0.0%	0.0%	5.6%
Steam	50.7%	0.0%	16.5%	36.3%
Wind Farm	0.0%	0.0%	0.0%	0.0%
Total	$69,574,458	$5,744,678	$271,623,607	$81,433,829

Economic and Noneconomic Generation

Economic generation includes units producing energy at an offer price less than or equal to LMP. Noneconomic generation includes units that are producing energy but at a higher offer price than the LMP. Noneconomic generation includes units assigned by PJM to run and units not assigned by PJM to run or to provide regulation. Regulation generation includes units assigned by PJM to provide regulation. The level of noneconomic generation is an indicator of the level of generation that may require operating reserve credits. However, the data are hourly and some generation that is noneconomic for an hour may receive adequate market revenues during other hours to offset any shortfall.[94]

Table 3-52 shows the percentage of total PJM self-scheduled generation, economic generation, noneconomic generation and regulation generation for 2008. The percentage of self-scheduled generation in all hours decreased 3.0 percentage points since 2007, economic generation increased 0.9 percentage points, noneconomic generation increased 1.6 points and regulation increased 0.6 percentage points.

Table 3-52 PJM self-scheduled, economic, noneconomic and regulation generation receiving operating reserve payments: Calendar year 2008

	All Hours	On Peak	Off Peak
Self-scheduled generation	43.1%	41.7%	46.4%
Economic generation	48.5%	52.9%	37.9%
Noneconomic generation	6.6%	4.6%	11.3%
Regulation generation	1.9%	0.8%	4.4%
Total	100%	100%	100%

94 Self-scheduled units were not included in either economic or noneconomic categories. Self-scheduled units are those units which indicate to PJM that they are self scheduled. Units which are operating, but are not assigned by PJM to run and are not self scheduled, are noneconomic.

Table 3-53 presents the share of self-scheduled, economic, noneconomic and regulation generation by unit type. (Each column adds to 100 percent.) In 2008, steam units represented 93.8 percent of all self-scheduled generation, 92.9 percent of all economic generation and 71.9 percent of noneconomic generation. Noneconomic combustion turbine generation decreased from 8.9 percent in 2007 to 4.7 percent in 2008, while noneconomic steam increased 5.0 percentage points.

Table 3-53 PJM generation by unit type receiving operating reserve payments: Calendar year 2008

	Self-Scheduled Generation	Economic Generation	Noneconomic Generation	Regulation Generation
Combined cycle	3.1%	5.8%	23.3%	9.2%
Combustion turbine	0.2%	0.4%	4.7%	0.3%
Diesel	0.2%	0.0%	0.1%	0.0%
Hydroelectric	2.5%	0.9%	0.0%	0.0%
Steam	93.8%	92.9%	71.9%	90.5%
Wind	0.2%	0.0%	0.0%	0.0%
Total	100%	100%	100%	100%

Table 3-54 presents the share of each unit type by self-scheduled, economic, noneconomic and regulation generation. (Each row adds to 100 percent.) For example, in 2008, 43.8 percent of steam unit generation was self-scheduled, 49.2 percent was economic, 5.2 percent was noneconomic and the remaining 1.8 percent was regulation generation. In 2008, 99.2 percent of wind generation and 72.1 percent of hydroelectric generation was self-scheduled. In 2008, 50 percent of combustion turbine generation was noneconomic, which is consistent with Table 3-51 which shows that a large percentage of balancing generator credits was paid to CTs. Combined-cycle noneconomic generation increased by 5.3 percentage points from 2007 and noneconomic combustion turbine generation increased 7.4 percentage points.

Table 3-54 PJM unit type generation distribution (By unit type receiving operating reserve payments): Calendar year 2008

	Self-Scheduled Generation	Economic Generation	Noneconomic Generation	Regulation Generation	Total
Combined cycle	22.8%	47.9%	26.4%	2.9%	100%
Combustion turbine	14.9%	34.0%	50.0%	1.1%	100%
Diesel	89.7%	6.0%	4.3%	0.0%	100%
Hydroelectric	72.1%	27.9%	0.0%	0.0%	100%
Steam	43.8%	49.2%	5.2%	1.8%	100%
Wind	99.2%	0.8%	0.0%	0.0%	100%

Geography of Balancing Credits and Charges

Table 3-55 compares the share of balancing operating reserve charges paid by generators and balancing operating reserve credits paid to generators in the Mid-Atlantic Region, to the share of charges paid by generators and credits paid by and to generators located within all other PJM control zones. The other control zones include those in the Western Region (the AEP, AP, ComEd, DAY and DLCO control zones) and in the Southern Region (the Dominion Control Zone). The new rules separate balancing operating reserves into Eastern and Western Regions, which are different than this definition. On average, 40.6 percent of balancing generator charges and 39.2 percent of LOC charges were paid by generators in the Mid-Atlantic Region while these generators received 64.9 percent of balancing generator credits and 25.8 percent of LOC credits. Table 3-55 also shows generator credits and charges as shares of total operating reserve credits and charges. On average, generator charges were 14.1 percent of all operating reserve charges and generator credits were 80.8 percent of all operating reserve credits.

Table 3-55 Monthly balancing operating reserve charges and credits to generators (By location): Calendar year 2008

	Mid-Atlantic Region				Other Control Zones					
	Generation Charge	LOC Charge	Generation Credit	LOC Credit	Generation Charge	LOC Charge	Generation Credit	LOC Credit	Generation and LOC Charges Share of Total Operating Reserves Charges	Generation and LOC Credits Share of Total Operating Reserves Credits
Jan	$2,779,405	$416,933	$25,933,909	$1,077,820	$3,465,890	$520,471	$8,663,850	$4,259,912	16.1%	89.7%
Feb	$1,882,858	$272,094	$13,013,407	$553,665	$2,429,882	$357,550	$7,063,095	$2,535,672	18.2%	85.5%
Mar	$1,501,880	$314,764	$11,313,168	$472,558	$1,607,090	$351,973	$4,344,515	$2,785,999	17.1%	85.7%
Apr	$1,025,306	$402,742	$10,070,917	$1,244,823	$1,948,928	$819,405	$6,020,712	$5,223,125	15.6%	83.6%
May	$1,338,311	$353,622	$13,970,992	$2,808,376	$2,242,991	$539,611	$3,547,565	$1,863,780	13.1%	65.2%
Jun	$4,036,002	$1,134,314	$32,013,721	$3,632,667	$5,455,511	$1,534,193	$19,030,186	$10,920,738	16.6%	89.6%
Jul	$2,005,513	$703,884	$19,494,752	$1,787,134	$2,870,811	$1,072,708	$15,521,659	$11,189,885	11.9%	85.8%
Aug	$943,341	$677,883	$7,159,590	$741,681	$1,382,157	$1,004,967	$7,628,860	$10,682,415	12.3%	80.7%
Sep	$1,167,003	$425,155	$11,422,817	$2,211,475	$2,631,141	$998,163	$8,617,645	$5,557,962	15.9%	84.8%
Oct	$791,852	$293,766	$7,500,479	$2,665,500	$1,452,304	$519,462	$4,347,088	$1,541,188	13.0%	68.2%
Nov	$1,097,894	$319,020	$11,503,444	$2,878,009	$1,782,839	$537,532	$4,756,207	$1,959,355	13.9%	78.7%
Dec	$596,709	$85,160	$12,910,690	$966,217	$767,946	$121,728	$5,774,337	$1,873,874	5.3%	72.5%
Average	40.6%	39.2%	64.9%	25.8%	59.4%	60.8%	35.1%	74.2%	14.1%	80.8%

Market Power Issues

The exercise of market power by units that are paid operating reserve credits also contributes to the level of operating reserve charges paid by PJM members. Market power issues are first examined by analyzing the characteristics of the top 10 units receiving operating reserve credits. The top 10 units are relevant, not because these are the only units with the ability to exercise market power, but because operating reserve credits have been so highly concentrated in payments to these units over the last several years. The focus on the top 10 units is illustrative. The market power analysis includes a calculation of the impact on total operating reserve credits of payments to generators associated with markups of price over cost in excess of the competitive level. Unit operating parameters also play a role in the level of operating reserve credits paid to units. The submission of inflexible operating parameters, including artificially long minimum run times, arbitrarily small numbers of starts, daily and hourly economic minimum and economic maximum points that are arbitrarily close or equal, contribute to higher levels of operating reserve credits.

A complete resolution of the market power issue in the payment of operating reserve credits must provide to PJM operators better tools for defining and making optimal economic choices and must define the relevant market, must determine when the market is structurally noncompetitive and must apply mitigation in such situations. The new operating reserve rules represent positive steps towards these goals.

Top 10 Units

A disproportionately large share of operating reserve credits has been paid to a small number of units and companies since 2001. This continued to be the case in 2008. As Table 3-56 shows, the top 10 units receiving total operating reserve credits, which makes up less than 1 percent of all units in PJM's footprint, received 18.78 percent of total operating reserve credits in 2008, a decrease from the 29.75 percent in 2007. The top 20 units received 25.74 percent of total operating reserve credits in 2008 and 39.8 percent in 2007. In 2008, six companies owned the units that received the 10 most total operating reserve credits. In 2007, the top generation owner received 8 percent of the total operating reserve credits paid, and in 2008, the top generation owner received 24.9 percent of the total operating reserve credits.

Table 3-56 Top 10 operating reserve revenue units (By percent of total system): Calendar years 2001 to 2008

	Top 10 Units Credit Share	Percent of Total PJM Units
2001	46.67%	1.81%
2002	32.01%	1.54%
2003	39.28%	1.28%
2004	46.28%	0.90%
2005	27.67%	0.79%
2006	29.72%	0.83%
2007	29.75%	0.84%
2008	18.78%	0.81%

Table 3-57 rank orders the top 10 units receiving total operating reserve credits, and the top 10 organizations receiving total operating reserve credits. The organization ranked number one does not necessarily own the unit that is ranked number one. The unit that received the most total operating reserve credits received $30,261,347 for 2008, or 7.1 of the total operating reserve credits paid to all units. The cumulative distribution column shows that the top 10 units had an 18.8 percent share of the total operating reserve credits in 2008. The top organization had a 24.9 percent share of the total credits, or $106,695,434. The top 10 organizations receiving credits had a cumulative share of 77.0 percent.

Table 3-57 Top 10 units and organizations receiving total operating reserve credits: Calendar year 2008

	Units			Organizations		
Rank	Total Credit	Total Credit Share	Total Credit Cumulative Distribution	Total Credit	Total Credit Share	Total Credit Cumulative Distribution
1	$30,261,347	7.1%	7.1%	$106,695,434	24.9%	24.9%
2	$12,901,176	3.0%	10.1%	$43,552,146	10.2%	35.1%
3	$6,151,524	1.4%	11.5%	$36,049,644	8.4%	43.5%
4	$5,205,118	1.2%	12.7%	$34,340,514	8.0%	51.5%
5	$4,860,844	1.1%	13.9%	$23,358,959	5.5%	56.9%
6	$4,658,680	1.1%	14.9%	$21,919,710	5.1%	62.1%
7	$4,291,570	1.0%	16.0%	$17,022,398	4.0%	66.0%
8	$4,270,922	1.0%	16.9%	$16,040,512	3.7%	69.8%
9	$4,149,643	1.0%	17.9%	$15,767,381	3.7%	73.5%
10	$3,706,280	0.9%	18.8%	$15,309,222	3.6%	77.0%

Table 3-58 rank orders the top 10 units receiving day-ahead operating reserve credits, and the top 10 organizations receiving day-ahead operating reserve credits. The top unit received $12,704,113, or 18.3 percent of the total day-ahead generator credits. The second unit had a 14.3 percent share, which when combined with the top unit was 32.6 percent of the total credits. The top organization received 41.8 percent of the day-ahead credits. The top 10 organizations received 82.7 percent of the day-ahead credits.

Table 3-58 Top 10 units and organizations receiving day-ahead generator credits: Calendar year 2008

	Units			Organizations		
Rank	Day Ahead Generator Credit	Day Ahead Generator Credit Share	Day Ahead Generator Credit Cumulative Distribution	Day Ahead Generator Credit	Day Ahead Generator Credit Share	Day Ahead Generator Credit Cumulative Distribution
1	$12,704,113	18.3%	18.3%	$29,100,202	41.8%	41.8%
2	$9,980,785	14.3%	32.6%	$6,450,891	9.3%	51.1%
3	$2,275,960	3.3%	35.9%	$4,556,031	6.5%	57.6%
4	$1,571,500	2.3%	38.1%	$3,429,155	4.9%	62.6%
5	$1,355,966	1.9%	40.1%	$3,345,546	4.8%	67.4%
6	$1,194,598	1.7%	41.8%	$2,931,890	4.2%	71.6%
7	$942,432	1.4%	43.2%	$2,591,653	3.7%	75.3%
8	$921,523	1.3%	44.5%	$1,821,745	2.6%	77.9%
9	$911,270	1.3%	45.8%	$1,705,059	2.5%	80.4%
10	$907,833	1.3%	47.1%	$1,611,128	2.3%	82.7%

Table 3-59 rank orders the top 10 units receiving synchronous condensing credits, and the top 10 organizations receiving synchronous condensing credits. The top organization received 96.7 percent of synchronous condensing credits.

Table 3-59 Top 10 units and organizations receiving synchronous condensing credits: Calendar year 2008

	Units			Organizations		
Rank	Synchronous Condensing Credit	Synchronous Condensing Credit Share	Synchronous Condensing Credit Cumulative Distribution	Synchronous Condensing Credit	Synchronous Condensing Credit Share	Synchronous Condensing Credit Cumulative Distribution
1	$537,309	9.4%	9.4%	$5,552,603	96.7%	96.7%
2	$520,789	9.1%	18.4%	$98,855	1.7%	98.4%
3	$494,227	8.6%	27.0%	$90,273	1.6%	99.9%
4	$474,565	8.3%	35.3%	$2,947	0.1%	100.0%
5	$434,112	7.6%	42.8%			
6	$398,650	6.9%	49.8%			
7	$394,881	6.9%	56.7%			
8	$392,302	6.8%	63.5%			
9	$188,842	3.3%	66.8%			
10	$184,737	3.2%	70.0%			

Table 3-60 rank orders the top 10 units receiving balancing generator credits, and the top 10 organizations receiving balancing generator credits. The top organization received 24.5 percent of total credits. The top ten organizations received a total of 79.2 percent of all the balancing generator credits.

Table 3-60 Top 10 units and organizations receiving balancing generator credits: Calendar year 2008

	Units			Organizations		
Rank	Balancing Generator Credit	Balancing Generator Credit Share	Balancing Generator Credit Cumulative Distribution	Balancing Generator Credit	Balancing Generator Credit Share	Balancing Generator Credit Cumulative Distribution
1	$17,537,872	6.5%	6.5%	$66,630,281	24.5%	24.5%
2	$5,296,063	1.9%	8.4%	$31,251,549	11.5%	36.0%
3	$4,815,831	1.8%	10.2%	$30,354,894	11.2%	47.2%
4	$4,510,532	1.7%	11.8%	$16,655,422	6.1%	53.3%
5	$4,393,615	1.6%	13.5%	$16,293,608	6.0%	59.3%
6	$3,518,939	1.3%	14.8%	$15,141,998	5.6%	64.9%
7	$3,319,601	1.2%	16.0%	$13,954,992	5.1%	70.0%
8	$3,036,191	1.1%	17.1%	$11,145,693	4.1%	74.1%
9	$2,904,919	1.1%	18.2%	$7,084,880	2.6%	76.7%
10	$2,674,513	1.0%	19.1%	$6,781,275	2.5%	79.2%

Table 3-61 rank orders the top 10 units receiving lost opportunity cost credits, and the top 10 organizations receiving lost opportunity cost credits. The top organization received 29.4 percent of the total lost opportunity cost credits and 89.2 percent were received by the top 10 organizations.

Table 3-61 Top 10 units and organizations receiving lost opportunity cost credits: Calendar year 2008

	Units			Organizations		
Rank	LOC Credit	LOC Credit Share	LOC Credit Cumulative Distribution	LOC Credit	LOC Credit Share	LOC Credit Cumulative Distribution
1	$3,427,138	4.2%	4.2%	$23,912,992	29.4%	29.4%
2	$3,411,938	4.2%	8.4%	$17,013,392	20.9%	50.3%
3	$3,121,215	3.8%	12.2%	$8,645,943	10.6%	60.9%
4	$2,248,038	2.8%	15.0%	$5,412,348	6.6%	67.5%
5	$2,113,906	2.6%	17.6%	$4,304,560	5.3%	72.8%
6	$2,056,261	2.5%	20.1%	$3,891,327	4.8%	77.6%
7	$2,039,438	2.5%	22.6%	$2,953,077	3.6%	81.2%
8	$2,013,224	2.5%	25.1%	$2,672,636	3.3%	84.5%
9	$1,974,982	2.4%	27.5%	$2,248,038	2.8%	87.3%
10	$1,964,603	2.4%	29.9%	$1,576,844	1.9%	89.2%

Figure 3-12 plots the four operating reserve generator categories to show the distribution of the units receiving credits. The vertical axis shows the cumulative percentage of credits that were received, while the horizontal axis shows the cumulative percentage of the units that received those credits. In this figure, 100 percent of units do not represent 100 percent of all PJM units, but 100 percent of all the units that received credits in each category. For example, 90 percent of the lost opportunity cost credits were received by approximately 22 percent of the units that received lost opportunity cost credits.

Figure 3-12 Cumulative distribution of units receiving credits (By operating reserve category): Calendar year 2008

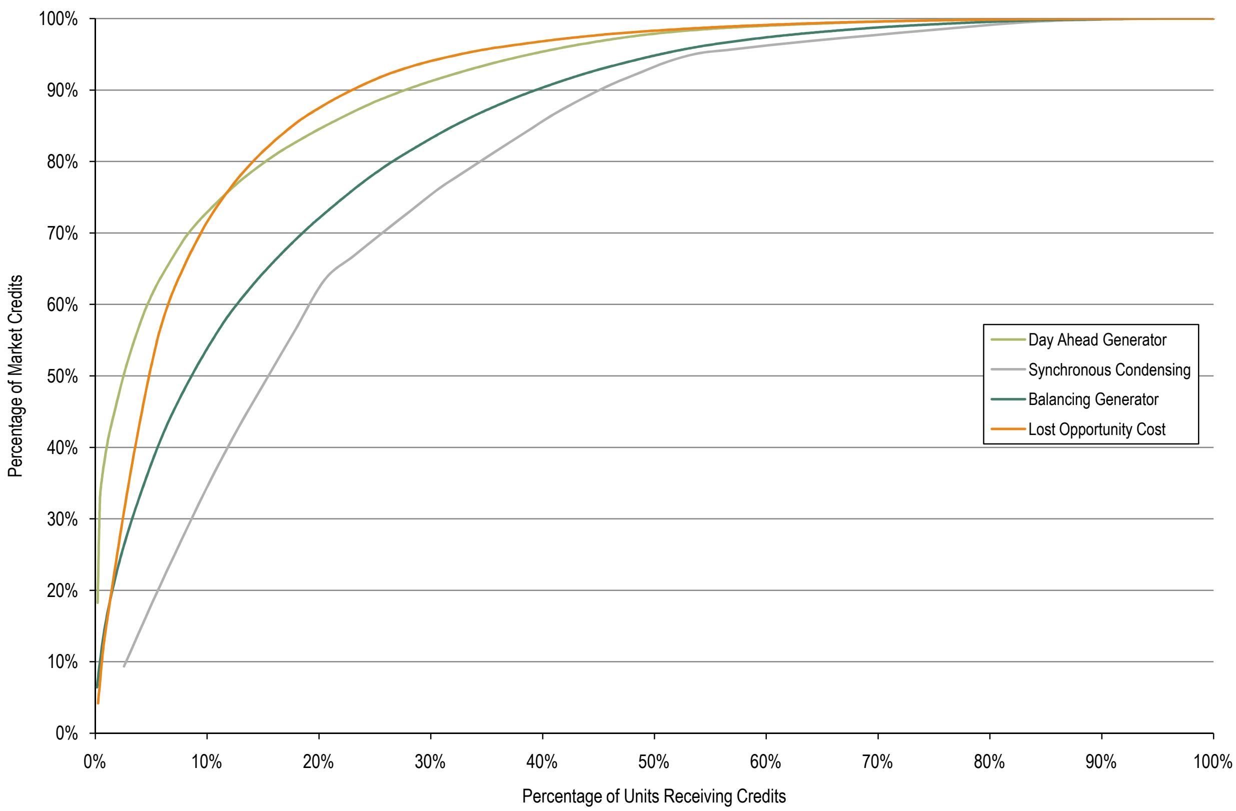
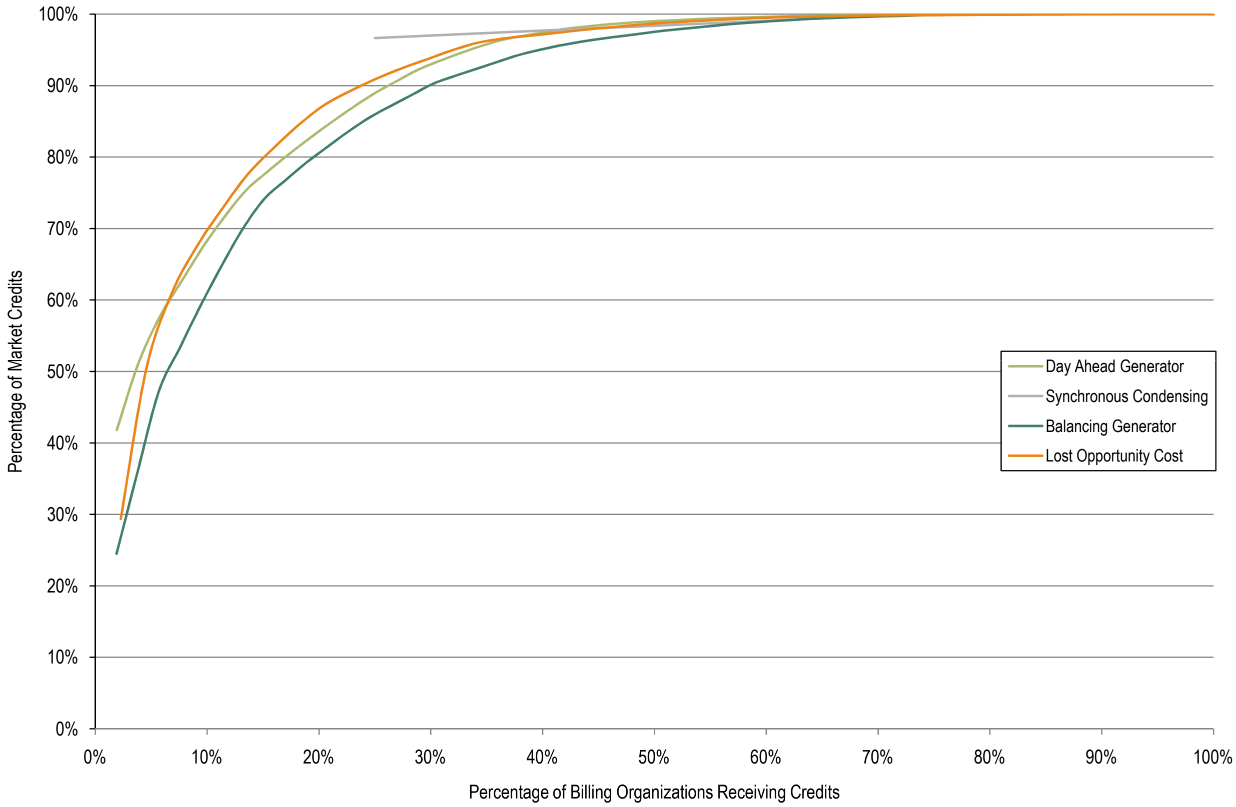


Figure 3-13 shows the distribution of credits among organizations. For example, 96.7 percent of synchronous condensing credits were paid to 25 percent of the organizations that received synchronous condensing credits.

Figure 3-13 Cumulative distribution of billing organizations receiving credits (By operating reserve market): Calendar year 2008



Markup

Unit Markup - Top 10 Units

The MMU analyzed the top 10 units receiving operating reserves credits to determine the contribution that markup makes to operating reserve payments.[95] Table 3-62 shows that the markup for the top 10 units averaged 6.5 percent in 2008, the lowest it has been since 2004 when the average markup for the top 10 units was 3.0 percent. The markup for the top 10 units is a weighted average, weighted by generator output when operating reserve credits are paid.

The generation owner with the largest share of total operating reserve credits received 53.7 percent of Energy Market operating reserve credits paid to the top 10 units and had a weighted average markup of 0.0 percent in 2008. The second generation owner received 16.4 percent of Energy Market operating reserve payments made to the top 10 units and had a weighted-average markup of 25.1

95 Markup is calculated as [(Price – Cost)/Cost] where cost represents the cost-based offer as defined in PJM "Manual 15: Cost Development Guidelines," Revision 9 (January 23, 2009). As a result, the markups here are not directly comparable to those calculated as [(Price – Cost)/Price].

percent and the third generation owner received 11.8 percent of Energy Market operating reserve payments made to the top 10 units and had a weighted-average markup of 5.4 percent in 2008.

For each year 2001 to 2006, and 2008, the top 10 units receiving operating reserve credits were either combined-cycle (CC) technology or conventional steam generation. In 2007, one unit out of the top 10 units receiving operating reserve credits was CT technology, while the rest remained CC technology or conventional steam generation. Steam units represented 22.3 percent of the credits received by the top 10 in 2008 and CC units accounted for 77.7 percent. The weighted average markup for those steam units was -1.4 percent, while combined-cycles had a weighted average markup of 9.0 percent, as seen in Table 3-62.

Table 3-62 Top 10 operating reserve revenue units markup: Calendar years 2001 to 2008

	Top Units' Markup	Steam Percent of Top 10	Steam Markup	Combined Cycle Percent of Top 10	Combined Cycle Markup	Combustion Turbine Percent of Top 10	Combustion Turbine Markup
2001	2.9%	60.2%	2.2%	39.8%	7.4%	0.0%	0.0%
2002	11.3%	54.4%	8.0%	45.6%	20.4%	0.0%	0.0%
2003	16.9%	50.1%	19.4%	49.9%	11.3%	0.0%	0.0%
2004	3.0%	12.2%	0.1%	87.8%	4.9%	0.0%	0.0%
2005	75.4%	20.3%	52.9%	79.7%	81.7%	0.0%	0.0%
2006	20.9%	9.6%	1.8%	90.4%	24.5%	0.0%	0.0%
2007	45.8%	18.2%	28.8%	77.6%	47.1%	4.2%	56.6%
2008	6.5%	22.3%	(1.4%)	77.7%	9.0%	0.0%	NA

Unit Markup - All Units

PJM's offer-capping rules had provided that specific units were exempt from offer capping, based on their date of construction. On May 17, 2008, exempt units became subject to offer capping.[96] Three of the top 10 units receiving total operating reserve credits in 2008 were among these previously exempt units and all were combined-cycles. Table 3-63 shows the average markup for previously exempt and non-exempt units for each unit class for days when those units received operating reserve credits in each category. The table covers the period from January 1, 2008 to May 17, 2008, the day exemptions were ended. Exempt combined-cycle and combustion turbine units that received operating reserves credits in the balancing market had a higher weighted markup than such units receiving day-ahead operating reserve credits.[97]

96 See the *2008 State of the Market Report*, Volume II, Section 2, "Energy Market, Part 1," at "Exempt Unit Markup."

97 No exempt steam units received day-ahead operating reserves in 2008. The -59.1 percent markup of an exempt unit in the balancing market was the result of a single unit that received credits of $11,101.

Table 3-63 Weighted average generator markup (By exemption status): January 1, 2008, through May 16, 2008

	Day-Ahead Market		Balancing Market	
Unit Class	Exempt	Non-Exempt	Exempt	Non-Exempt
All Units	3.6%	12.8%	29.4%	(7.7%)
Combined Cycle	3.2%	8.2%	31.8%	(16.9%)
Combustion Turbine	44.4%	56.1%	51.4%	8.5%
Diesel	14.4%	4.7%	13.3%	(40.5%)
Steam	NA	16.7%	(59.1%)	(7.4%)

Table 3-64 shows the total credits received by both previously exempt and non-exempt units in each market. Non-exempt combustion turbines in the balancing market received the most credits and had a weighted markup of 8.5 percent.

Table 3-64 Day-ahead and balancing market credits (By exemption status): January 1, 2008, through May 16, 2008

	Day-Ahead Market		Balancing Market	
Unit Class	Exempt	Non-Exempt	Exempt	Non-Exempt
All Units	$1,613,871	$16,160,764	$19,058,145	$95,176,249
Combined Cycle	$1,467,279	$10,221,571	$14,059,550	$14,132,198
Combustion Turbine	$144,778	$268,365	$4,653,060	$59,323,130
Diesel	$1,814	$875	$334,435	$1,044,442
Steam	$0	$5,669,954	$11,101	$20,676,479

If exempt combined-cycle units in the balancing market had a zero percent markup rather than 31.8 percent, and all other things were held constant, total balancing credits for exempt combined-cycle units would have lower by $3,392,482.[98] (See Table 3-65.)

Table 3-65 Impact of markup on operating reserve credits (By exemption status and market): January 1, 2008, through May 16, 2008

	Day-Ahead Market		Balancing Market	
Unit Class	Exempt	Non-Exempt	Exempt	Non-Exempt
All Units	$56,150	$1,832,633	$4,324,776	
Combined Cycle	$46,152	$772,201	$3,392,482	
Combustion Turbine	$44,544	$96,414	$1,579,438	$4,660,514
Diesel	$228	$39	$39,314	
Steam		$813,265		

98 There are blank cells in Table 3-65 corresponding to negative mark ups. Total balancing credits were recalculated only for positive markups.

Unit Operating Parameters

Operating reserve credits also result from the submission of artificially restrictive, unit-specific operating parameters. For example, if a unit is needed by PJM for reliability purposes and if that unit, with a price offer equal to its cost offer, has only one permitted start per day although it is capable of three, has a 24-hour minimum run time although its actual minimum run time is four hours and a two-hour start time although its actual start time is 30 minutes, then it receives higher operating reserve payments than if those operating parameters were not in place. Once a unit is turned on for PJM for reliability reasons, operating reserve rules require that PJM pay the unit the difference between market revenues and its offer, including its offered operating parameters. Thus, PJM members have to pay this unit its offer price for 24 hours although if the unit had offered its actual capability to PJM, payments would have been made for only four hours. If a unit sets its economic minimum output level at, or close to, its economic maximum output level, although the actual minimum and maximum output levels have a significant differential, PJM members have to pay the unit its offer price for its inflated offered economic minimum. If the unit had offered its actual economic minimum to PJM, PJM could have reduced the unit's output to that minimum when LMP fell below its offer price, thus reducing operating reserve credits and charges. Restrictive operating parameters can also interact with unit-specific markups to increase operating reserve payments to units.

The new operating reserves rules address the parameter issue by establishing a parameter limited schedule that will help prevent the use of arbitrarily inflexible operating parameters when units have local market power.[99]

99 See PJM "Parameter Limited Schedule Matrix," for parameter levels at <http://www.pjm.com/markets-and-operations/energy/~/media/markets-ops/energy/op-reserves/20080916-parameter-limited-schedule-matrix.ashx>.

SECTION 4 – INTERCHANGE TRANSACTIONS

PJM market participants import energy from, and export energy to, external regions continuously. The transactions involved may fulfill long-term or short-term bilateral contracts or take advantage of short-term price differentials. The external regions include both market and non market balancing authorities.

Overview

Interchange Transaction Activity

- **Aggregate Imports and Exports in the Real-Time Energy Market.** During 2008, PJM was a net exporter of energy in the Real-Time Market for all months except December. In the Real-Time Market, monthly net interchange averaged -1,010 GWh.[1] Gross monthly import volumes averaged 3,962 GWh while gross monthly exports averaged 4,972 GWh.

- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** In 2008, gross imports in the Day-Ahead Energy Market were 90 percent of the Real-Time Market's gross imports (85 percent in 2007) while gross exports in the Day-Ahead Market were 106 percent of the Real-Time Market's gross exports (103 percent in 2007) and net interchange in the Day-Ahead Energy Market exceeded net interchange in the Real-Time Energy Market by 58 percent. In the Day-Ahead Market, monthly net interchange averaged -1,732 GWh. Gross monthly import volumes averaged 3,552 GWh while gross monthly exports averaged 5,284 GWh.

- **Interface Imports and Exports in the Real-Time Market.** In the Real-Time Market in 2008, there were net exports at 16 of PJM's 20 interfaces. The top three net exporting interfaces in the Real-Time Market accounted for 53 percent of the total net exports: PJM/New York Independent System Operator, Inc. (NYIS) with 24 percent, PJM/Neptune (NEPT) with 18 percent, and PJM/Tennessee Valley Authority (TVA) with 11 percent of the net export volume. Four PJM interfaces had net imports, with two importing interfaces accounting for 77 percent of net import volume: PJM/Ohio Valley Electric Corporation (OVEC) with 59 percent and PJM/Michigan Electric Coordinated System (MECS) with 18 percent.

- **Interface Imports and Exports in the Day-Ahead Market.** In the Day-Ahead Market, there were net exports at 16 of PJM's 20 interfaces. The top three net exporting interfaces accounted for 59 percent of the total net exports, PJM/western Alliant Energy Corporation (ALTW) with 26 percent, PJM/Northern Indiana Public Service Company (PJM/NIPS) with 18 percent and PJM/NEPTUNE (NEPT) with 15 percent. There were net imports in the Day-Ahead Market at four of PJM's 20 interfaces. The top two importing interfaces accounted for 92 percent of the total net imports, PJM/OVEC with 75 percent and PJM/Ameren – Illinois (AMIL) with 17 percent.

1 Net interchange is gross import volume less gross export volume. Thus, positive net interchange is equivalent to net imports and negative net interchange is equivalent to net exports.

Interactions with Bordering Areas

- **PJM Interface Pricing with Organized Markets.**

  — **PJM and Midwest ISO Interface Pricing.** During 2008, the relationship between prices at the PJM/MISO Interface and at the MISO/PJM Interface reflected economic fundamentals as did the relationship between interface price differentials and power flows between PJM and the Midwest ISO.

  — **PJM and New York ISO Interface Pricing.** During 2008, the relationship between prices at the PJM/NYIS Interface and at the NYISO/PJM proxy bus reflected economic fundamentals, as did the relationship between interface price differentials and power flows between PJM and NYISO. Both continued to be affected by differences in institutional and operating practices between PJM and NYISO.

- **PJM TLRs.** The number of transmission loading relief procedures (TLRs) issued by PJM increased by 87.5 percent, from 80 in 2007 to 150 in 2008. The increase in TLRs declared by PJM can be attributed to transmission line outages caused by storms and tornados. These outages limited the ability to utilize market signals to manage constraints.

- **Operating Agreements with Bordering Areas.**

  — **PJM and New York Independent System Operator, Inc. Joint Operating Agreement (JOA).**[2] On May 22, 2007, the JOA between PJM and the New York Independent System Operator (NYISO) became effective. This agreement was developed to improve reliability. It also formalizes the process of electronic checkout of schedules, the exchange of interchange schedules to facilitate calculations for available transfer capability (ATC) and standards for interchange revenue metering. While the JOA does not include provisions for market-based congestion management or other market-to-market activity, at the request of PJM, PJM and the NYISO began discussion of a market-based congestion management protocol.

  — **PJM and Midwest ISO Joint Operating Agreement.** The Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C., executed on December 31, 2003, continued in 2008. The market-based congestion management process is reviewed and modified as necessary through the Congestion Management Process (CMP) protocols.[3]

  — **PJM, Midwest ISO and TVA Joint Reliability Coordination Agreement.**[4] The Joint Reliability Coordination Agreement (JRCA) executed on April 22, 2005, provides for comprehensive reliability management among the wholesale electricity markets of the Midwest ISO and PJM and the service territory of TVA. The agreement continued to be in effect through 2008.

2 See PJM. “Joint Operating Agreement Among And Between New York Independent System Operator Inc. And PJM Interconnection, L.L.C.” (May 22, 2007) (Accessed January 16, 2009) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/20071102-nyiso-pjm.ashx> (208 KB).

3 See PJM. “Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.” (November 1, 2007) (Accessed January 16, 2009) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/joa-complete.ashx> (1,534 KB).

4 See PJM. “Congestion Management Process (CMP) Master” (May 1, 2008) (Accessed January 16, 2009) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/20080502-miso-pjm-tva-baseline-cmp.ashx> (432 KB).

— **PJM and Progress Energy Carolinas, Inc. Joint Operating Agreement.**[5] On September 9, 2005, the United States Federal Energy Regulatory Commission (FERC) approved a JOA between PJM and Progress Energy Carolinas, Inc. (PEC), with an effective date of July 30, 2005. The agreement remained in effect through 2008.

— **PJM and Virginia and Carolinas Area (VACAR) South Reliability Coordination Agreement.**[6] On May 23, 2007, PJM and VACAR South (VACAR is a subregion within the NERC Southeastern Electric Reliability Council (SERC) Region) entered into a reliability coordination agreement. It provides for system and outage coordination, emergency procedures and the exchange of data. Provisions are also made for regional studies and recommendations to improve the reliability of interconnected bulk power systems.

- **Interface Pricing Agreements with Individual Companies.** PJM entered into confidential locational interface pricing agreements with Duke Energy Carolinas, Progress Energy Carolinas and North Carolina Municipal Power Agency (NCMPA) in 2007 that provided more advantageous pricing to these companies than the applicable interface pricing rules. Each of these agreements established a locational price for purchases and sales between PJM and the individual company that applies under specified conditions. There are a number of issues with these agreements including that they were not made public until specifically requested by the Market Monitoring Unit (MMU), that the pricing was not available to other participants in similar circumstances, that the pricing was not designed to reflect actual power flows, that the pricing did not reflect full security constrained economic dispatch in the external areas and that the pricing did not reflect appropriate price signals. PJM recognized that the price signals in the agreements were inappropriate and notified the counterparties that PJM would terminate the agreements effective January 31, 2009.

- **Consolidated Edison Company of New York, Inc. (Con Edison) and Public Service Electric and Gas Company (PSE&G) Wheeling Contracts.** During 2008, PJM continued to operate under the terms of the operating protocol developed in 2005.[7] Significant progress was also made on the 19 items identified in the work plan to improve protocol performance in 2008.

- **Neptune Underwater Transmission Line to Long Island, New York.** On July 1, 2007, a 65-mile direct current (DC) transmission line from Sayreville, New Jersey, to Nassau County on Long Island, including undersea and underground cable, was placed in service. This is a merchant 230 kV transmission line with a capacity of 660 MW. The line is bi-directional, but in 2008 power flows were only from PJM to New York. The average hourly flow for 2008 was -572 MW.

5 See PJM. "Joint Operating Agreement (JOA) between Progress Energy Carolinas, Inc. and PJM" (July 29, 2005) (Accessed January 16, 2009) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/20081114-progress-pjm-joa.ashx> (2.98 MB).

6 See PJM. "Adjacent Reliability Coordinator Coordination Agreement" (May 23, 2007) (Accessed January 16, 2009) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/executed-pjm-vacar-rc-agreement.ashx> (528 KB).

7 111 FERC ¶ 61,228 (2005).

Interchange Transaction Issues

- **Spot Import.** Prior to April 1, 2007, PJM did not limit non-firm service imports that were willing to pay congestion, including spot imports, secondary network service imports and bilateral imports using non-firm point-to-point service. However, PJM interpreted its Joint Operating Agreement (JOA) with Midwest ISO (MISO) to require a limitation on cross-border transmission service and energy schedules in order to limit the impact of such transactions on selected external flowgates.[8] The rule caused the availability of spot import service to be limited by ATC on the transmission path. As a result of the rule, requests for service sometimes exceeded the amount of service available to customers. Unlike non-firm point-to-point WPC service, spot import (a network service) is provided at no charge to the market participant offering into the PJM spot market.

  The new spot import rules have incented participant actions to evade the limits and to hoard spot import capability. The MMU recommends that PJM reconsider whether the new approach to limiting spot import service is required or whether a return to the prior policy with an explicit system of managing any related congestion is preferable.

- **Up-To Congestion.** In 2008, market participants requested that PJM increase the maximum value for up-to congestion offers, and to also allow negative offers for these transactions. PJM expressed concerns regarding the mismatch between up-to congestion transactions in the Day-Ahead Market and real-time transactions.[9] In the Day-Ahead Energy Market, an up-to congestion import transaction is submitted and modeled as an injection at the interface and a withdrawal at a specific PJM node. In real time, the power does not flow to the PJM node specified in the day-ahead transaction. This mismatch results in inaccurate pricing and can provide a gaming opportunity. Increasing the offer cap, and allowing negative offers, could potentially increase the cleared volume of up-to congestion transactions, and aggravate the issue.

  On February 21, 2008, the MRC approved PJM's proposed resolution to the request for implementation on March 1, 2008.[10] The proposal allowed for an increased offer cap from \$25 to ± \$50, and explicitly allowed for negative offers. PJM also eliminated certain available sources and sinks in an effort to address the mismatches between the Day-Ahead and Real-Time Markets.

  The MMU recommends that PJM consider eliminating all internal PJM buses for use in up-to congestion bidding. In effect, the use of specific buses is equivalent to creating a scheduled transaction which will not equal the actual corresponding power flow.

8 See "WPC White Paper" (April 20, 2007) (Accessed December 29, 2008) <http://www.pjm.com/~/media/etools/oasis/wpc-white-paper.ashx> (97 KB).
9 See PJM. "Up-to Congestion Transactions. Proposed Interim Changes Pending Development of a Spread Product" (February 21, 2008) (Accessed February 18, 2009) <http://www.pjm.com/~/media/committees-groups/committees/mrc/20080221-item-03-up-to-congestion-transactions.ashx> (38KB).
10 See PJM. "20080221-minutes.pdf" (February 21, 2008) (Accessed January 15, 2009) <http://www.pjm.com/Media/committees-groups/committees/mrc/20080221-minutes.pdf > (61KB).

- **Loop Flows.** Loop flows are measured as the difference between actual and scheduled flows at one or more specific interfaces. Loop flows can arise from transactions scheduled into, out of or around the PJM system on contract paths that do not correspond to the actual physical paths that the energy takes. Although PJM's total scheduled and actual flows differed by 1.7 percent in 2008, greater differences existed at individual interfaces.[11] Loop flows are a significant concern because they have negative impacts on the efficiency of market areas with explicit locational pricing, including impacts on locational prices, on Financial Transmission Right (FTR) revenue adequacy and on system operations, and can be evidence of attempts to game such markets.

  — **Loop Flows at the PJM/MECS and PJM/TVA Interfaces.** As it had in 2007, the PJM/Michigan Electric Coordinated System (MECS) Interface continued to exhibit large imbalances between scheduled and actual power flows (-14,014 GWh in 2008 and -10,813 GWh in 2007), particularly during the overnight hours. The PJM/TVA Interface also exhibited large mismatches between scheduled and actual power flows (4,065 GWh in 2008 and 5,906 GWh in 2007), although these mismatches have declined since the consolidation of the former PJM southeast and southwest pricing points in October 2006. The net difference between scheduled flows and actual flows at the PJM/TVA Interface was imports while the net difference at the PJM/MECS Interface was exports.

  — **Loop Flows at PJM's Southern Interfaces.** The improvement in the difference between scheduled and actual power flows at PJM's southern interfaces (PJM/TVA and PJM/Eastern Kentucky Power Corporation (EKPC) to the west and PJM/eastern portion of Carolina Power & Light Company (CPLE), PJM/western portion of Carolina Power & Light Company (CPLW) and PJM/DUK to the east) observed in late 2006 and during 2007 was sustained in 2008 although the loop flows across the southern interfaces increased in 2008 from 2007. These improvements followed the changes from the Southeast and Southwest interface pricing points to the SOUTHIMP and SOUTHEXP interface pricing points that occurred on October 1, 2006.

11 The *2007 State of the Market Report* reported the difference between scheduled and actual flows as 0.5 percent. The calculation method incorrectly accounted for some dynamic schedules. The recalculated 2007 difference is 1.6 percent.

- **Loop Flows at PJM's Northern Interfaces.** In 2008, new loop flows were created when pricing rules gave participants an incentive to schedule power flows in a manner inconsistent with the associated actual power flows. In 2008, market participants scheduled transactions on a path from the NYISO to PJM through Ontario's Independent Electricity System Operator (IESO) and Midwest ISO systems, rather than reflecting the actual power flows which were primarily directly from NYISO to PJM. The participants faced a price incentive to engage in this behavior. When export transactions were scheduled from NYISO to Ontario, participants paid the lower export price at NYISO's Ontario interface rather than the higher export price at NYISO's PJM interface. The export price differences were more than enough to cover the cost of transmission through Ontario and MISO into PJM. When the export transactions were approved in the NYISO hourly market, the NYISO committed additional generation to support the transactions. The actual flow of energy that resulted was primarily directly from NYISO to PJM across the PJM/NYISO Interface. PJM's interface pricing calculations correctly reflected the actual power flows, but NYISO's interface pricing did not. One result was increased congestion charges in the NYISO system. PJM's interface pricing rules eliminated the incentive to schedule power flows on paths inconsistent with actual power flows in order to take advantage of price differences. In this case, PJM interface pricing rules resulted in PJM paying for the import based on its source in the NYISO and disregarded the scheduled path.

- **Data Required for Full Loop Flow Analysis.** A complete analysis of loop flow across the Eastern Interconnection could enhance overall market efficiency and shed light on the interactions among market and non market areas. This is important because loop flows have negative impacts on the efficiency of market prices in markets with explicit locational pricing and can be evidence of attempts to game such markets. Loop flows also have poorly understood impacts on non market areas. More broadly, a complete analysis of loop flow could advance the overall transparency of electricity transactions. The term non market area is a misnomer in the sense that all electricity transactions are part of the broad energy market in the Eastern Interconnection. There are areas with transparent markets, and there are areas with less transparent markets, but these areas together comprise a market, and overall market efficiency would benefit from the increased transparency that would derive from a better understanding of loop flow.

  The MMU recommends that PJM and the Midwest ISO reiterate their initial recommendation to create an energy schedule tag archive, as this would provide the transparency necessary for a complete loop flow analysis. The data required for a meaningful loop flow analysis include tag data, market flow impact data, actual flowgate flows data and balancing authority ACE data for the Eastern Interconnection. The MMU recommends that the RTOs request action, and that both NERC and FERC consider taking the action required to make these data available to the RTOs and market monitors to make a full market analysis possible.

Conclusion

Transactions between PJM and multiple balancing authorities in the Eastern Interconnection are part of a single energy market. While some of these balancing authorities are termed market areas and some are termed non market areas, all electricity transactions are part of a single energy market. Nonetheless, there are significant differences between market and non market areas. Market areas, like PJM, include essential features such as locational marginal pricing, financial hedging tools (FTRs and Auction Revenue Rights (ARRs) in PJM) and transparent, least cost, security constrained economic dispatch for all available generation. Non market areas do not include these features. The market areas are extremely transparent and the non market areas are nontransparent.

The MMU analyzed the transactions between PJM and neighboring balancing authorities for 2008, including evolving transaction patterns, economics and issues. While PJM market participants historically imported and exported energy primarily in the Real-Time Energy Market, that is no longer the case. PJM continued to be a net exporter of energy and a large share of both import and export activity occurred at a small number of interfaces. Three interfaces accounted for 53 percent of the total real-time net exports and two interfaces accounted for 77 percent of the real-time net import volume. Three interfaces accounted for 59 percent of the total day-ahead net exports and two interfaces accounted for 92 percent of the day-ahead net import volume.

As the data show, there is a substantial level of transactions between PJM and the contiguous balancing authorities. The transactions with other market areas are largely driven by the market fundamentals within each area and between market areas. However, there is room to improve current market-to-market coordination to ensure that these areas together more closely approach the outcomes and opportunities of a single, transparent market. The transactions with non market areas are driven by a mix of incentives, including market fundamentals, but are more difficult to manage because of the inherent inconsistency between the contract path approach taken in non market areas and the explicit locational price approach in market areas. A significant issue is the ability of non market transactions to impose uncompensated costs on market areas in the absence of transparency and appropriate market signals. The reverse can also occur. For interactions with both market and non market areas, the goal should be to increase the role of market forces consistent with actual power flows and more closely approach the outcomes and opportunities of a single, transparent market.

In order to manage interactions with other market areas, PJM has entered into formal agreements with a number of balancing authorities. The redispatch agreement between PJM and the Midwest ISO is a model for such agreements and is being continuously improved. As interactions with external areas are increasingly governed by economic fundamentals, interface prices and volumes reflect supply and demand conditions and the number of required interventions in the market has declined. However, more needs to be done to assure that market signals are used to manage constraints affecting interarea transactions. PJM and NYISO, as neighboring market areas, should develop market-based congestion management protocols as soon as practicable. In addition, PJM should continue its efforts to gain access to the data required to understand loop flows in real-time and to ensure that responsible parties pay their appropriate share of the costs of redispatch.

In order to manage interactions with non market areas, PJM has entered into coordination agreements with other balancing authorities as a first step. In addition, PJM has attempted to address loop flows by creating and modifying interface prices that reflect actual power flows, regardless of contract path. Loop flows are also managed through the use of redispatch and TLR procedures. PJM has entered into dynamic scheduling agreements with generation owners for specific units to permit transparent, market-based signals and responses. PJM has modified the rules governing the use of limited transaction ramp capability between PJM and contiguous balancing authorities to help ensure that transactions are free to respond to market signals and to reduce the ability to game or hoard ramp. PJM also entered into agreements with specific balancing authorities for separate interface pricing that have been questioned with respect to transparency and equal access. PJM needs to ensure that such pricing is transparent and that all participants have access to the defined pricing when in the same position.

Loop flows are measured as the difference between actual and scheduled (contract path) flows at one or more specific interfaces. Loop flows do not exist within markets because power flows are explicitly priced under locational marginal pricing, but markets can create loop flows in external balancing authorities. PJM attempts to manage loop flows by creating interface prices that reflect the actual power flows, regardless of contract path. But this approach cannot be completely successful as long as it is possible to schedule a transaction and be paid based on that schedule, regardless of how the power flows.

PJM continues to face significant loop flows for reasons that continue not to be fully understood as a result of inadequate access to the required data. A complete analysis of loop flow across the Eastern Interconnection could improve overall market efficiency, shed light on the interactions among market and non market areas and permit market based congestion management across the Eastern Interconnection. Loop flows have negative impacts on the efficiency of market prices in markets with explicit locational pricing and can be evidence of attempts to game such markets. Loop flows also have poorly understood impacts on non market areas. The MMU recommends that the RTOs request action, and that both NERC and FERC consider taking the action required to make these data available to the RTOs and market monitors to make a full market analysis possible.

PJM needs to continue to pay careful attention to all the mechanisms used to manage flows at the interfaces between PJM and surrounding areas. PJM manages its interface with external areas, in part, through limitations on the amount of change in net interchange within 15-minute intervals. The change in net interchange is referred to as ramp. Changes in net interchange affect PJM operations and markets as they require increases or decreases in generation to meet load. As a result of the fact that ramp is free but is a valuable resource, there are strong incentives to game the ramp rules. The same is true of spot import service. Up-to congestion service is a market option used to import power to or export power from PJM which can create mismatches between transactions in the Day-Ahead Energy Market and the Real-Time Energy Market that result in inaccurate pricing and can provide a gaming opportunity.

Interchange Transaction Activity

Aggregate Imports and Exports

PJM continued to be a net exporter of power in 2008. (See Figure 4-1, Figure 4-2 and Figure 4-3).[12] During 2008, PJM was a net exporter of energy in the Real-Time Market for all months except December. Total net interchange of -12,124 GWh was less than net interchange of -14,274 GWh

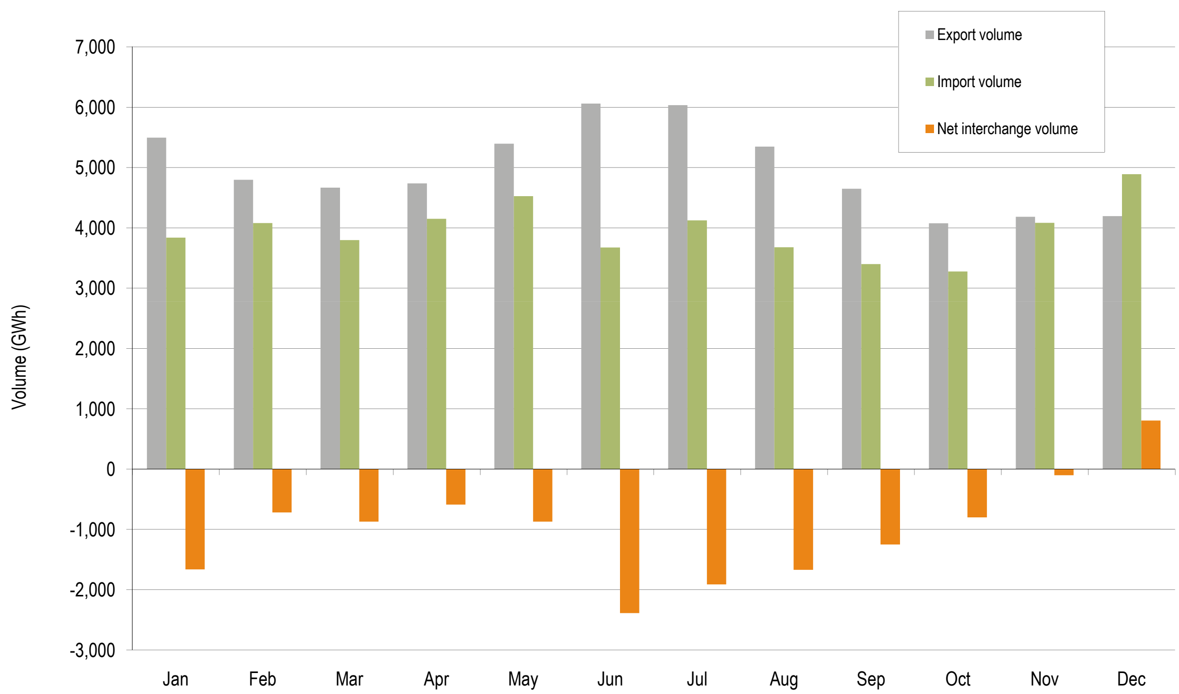
12 Calculated values shown in Section 4, "Interchange Transactions," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

in 2007.[13] The peak month for net interchange was June in 2008, -2,388 GWh; it had been August in 2007, -3,470 GWh. Monthly gross exports averaged 4,972 GWh and monthly gross imports averaged 3,962 GWh, for an average monthly net interchange of -1,010 GWh.

In the Day-Ahead Market, PJM continued to be a net exporter of energy as well. Total net interchange was -20,783 GWh. The peak month for net interchange was June, -2,657 GWh. Monthly gross exports averaged 5,284 GWh and monthly gross imports averaged 3,552 GWh, for an average monthly net interchange of -1,732 GWh.

While PJM market participants historically imported and exported energy primarily in the Real-Time Energy Market, that is no longer the case. (See Figure 4-2.) Transactions in the Day-Ahead Market create financial obligations to deliver in the Real-Time Market and to pay operating reserve charges based on differences between the transaction MW in the Day-Ahead and Real-Time Energy Markets. In 2008, gross imports in the Day-Ahead Energy Market were 90 percent of the Real-Time Market's gross imports (85 percent in 2007) while gross exports in the Day-Ahead Market were 106 percent of the Real-Time Market's gross exports (103 percent in 2007) and net interchange in the Day-Ahead Energy Market exceeded the net interchange in the Real-Time Energy Market by 58 percent.

Figure 4-1 PJM real-time scheduled imports and exports: Calendar year 2008



13 Note: The totals referenced for 2007 do not match those stated in the *2007 State of the Market Report*. The *2007 State of the Market* Report did not include wheeling transactions. Additionally, the totals presented in the *2007 State of the Market Report* for the AMIL interface were not properly accounted for after the merger of the CILC, IP and AMRN control areas.

Figure 4-2 PJM day-ahead scheduled imports and exports: Calendar year 2008

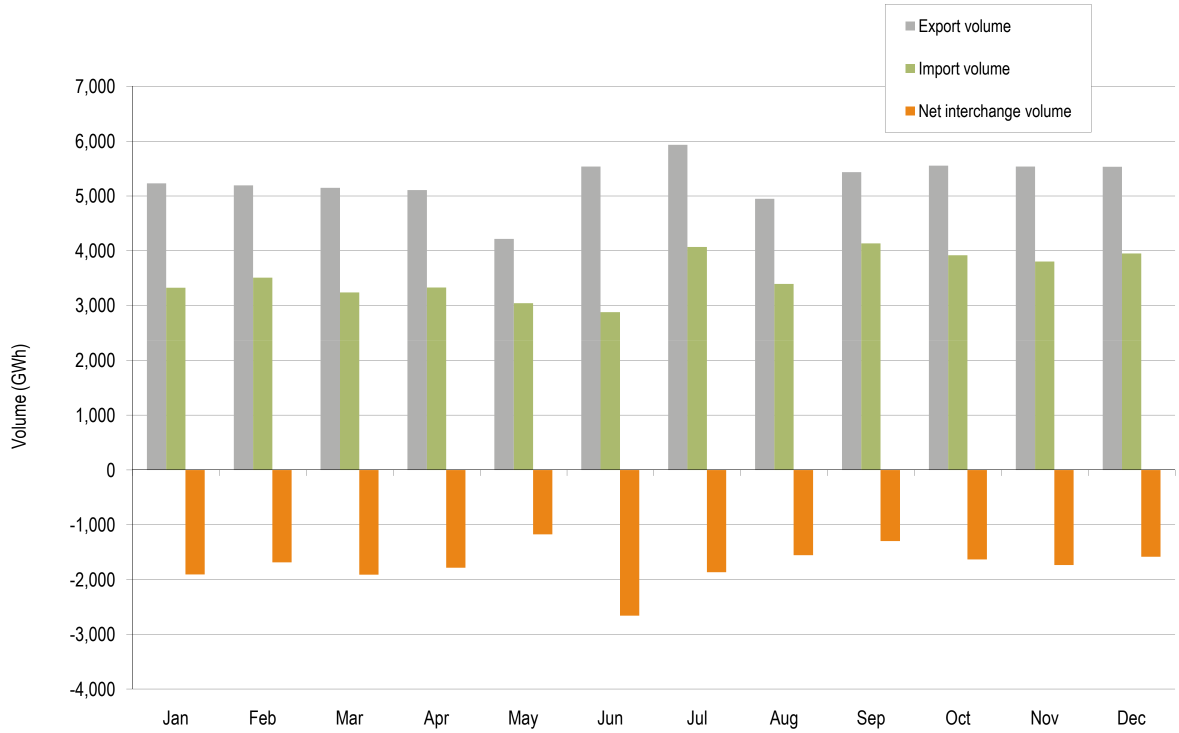
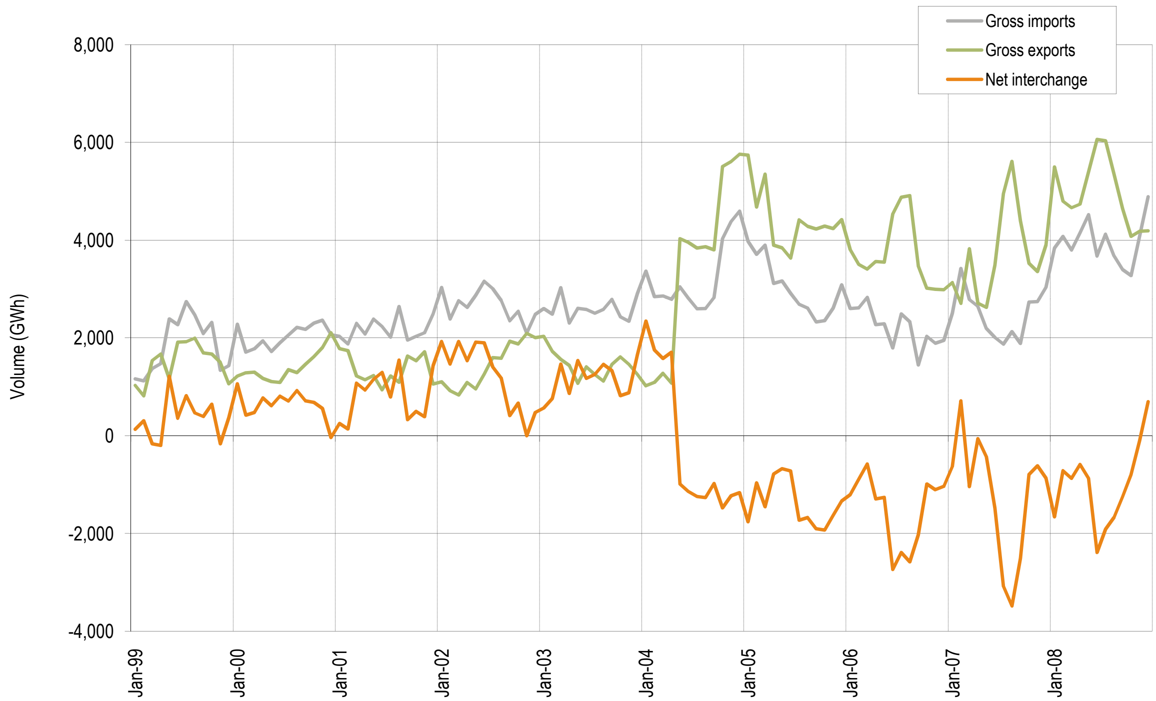


Figure 4-3 shows real-time import and export volume for PJM from 1999 through 2008. PJM became a consistent net exporter of energy in 2004, coincident with the expansion of the PJM footprint, and has continued to be a net exporter since that time. During 2008, imports continued to be lower than exports, with the exception of December. Exports peaked in June, while imports peaked in December.

Figure 4-3 PJM scheduled import and export transaction volume history: Calendar years 1999 to 2008



Interface Imports and Exports

Total imports and exports are comprised of flows at each PJM interface. Net interchange in the Real-Time Market is shown by interface for 2008 in Table 4-1 while gross imports and exports are shown in Table 4-2 and Table 4-3 respectively. Net interchange in the Day-Ahead Market is shown by interface for 2008 in Table 4-4 while gross imports and exports are shown in Table 4-5 and Table 4-6 respectively.

In March of 2007, Ameren (AMRN), Central Illinois Light Company (CILC) and Illinois Power Company (IP) merged to form Ameren-Illinois. As a result, PJM modified its interfaces. The PJM/AMRN, PJM/CILC and PJM/IP Interfaces were retired and a new PJM/Ameren – Illinois (AMIL) interface was created. The *2007 State of the Market Report* included the partial years' totals in the summaries, accounting for 23 total interfaces (20 interfaces at the end of 2007, and the three retired, partial year, interfaces (AMRN, CILC and IP). For 2008, there were no changes to interfaces with PJM.[14]

In 2008, there were net exports in the Real-Time Market at 16 of PJM's 20 interfaces. (See Table 4-7 for active interfaces during 2008.) The top three exporting interfaces accounted for 53 percent of PJM's total net exports, PJM/NYIS with 24 percent, PJM/NEPT with 18 percent and PJM/TVA with 11 percent of the net export volume.

14 See the *2007 State of the Market Report* (March 11, 2008), p. 200, for the active interfaces for calendar year 2007.

In 2008, there were net exports in the Day-Ahead Market at 16 of PJM's 20 interfaces. The top three exporting interfaces accounted for 59 percent of PJM's total net exports, PJM/ALTW with 26 percent, PJM/NIPS with 18 percent and PJM/NEPT with 15 percent.

There were net imports in the Real-Time Market at four of PJM's interfaces. Two net importing interfaces accounted for 77 percent of PJM's net import volume, PJM/OVEC with 59 percent and PJM/MECS with 18 percent of the net import volume.

There were net imports in the Day-Ahead Market at four of PJM's 20 interfaces. The top two net importing interfaces accounted for 92 percent of PJM's total net imports, PJM/OVEC with 75 percent and PJM/AMIL with 17 percent.

Table 4-1 Real-time scheduled net interchange volume by interface (GWh): Calendar year 2008

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
ALTE	(178.8)	(144.9)	(131.7)	(136.0)	(99.2)	(161.6)	(151.7)	(127.2)	(123.8)	(123.1)	(76.7)	(31.7)	(1,486.4)
ALTW	(120.2)	(160.5)	(130.3)	(106.9)	(95.0)	(131.7)	(101.6)	(102.6)	(105.3)	(119.0)	(60.4)	(105.3)	(1,338.8)
AMIL	(28.0)	12.8	(6.3)	8.3	(8.6)	(77.0)	(93.6)	(48.8)	26.7	17.5	7.2	35.6	(154.2)
CIN	181.1	67.7	201.0	469.9	562.2	336.3	(11.3)	132.7	97.3	44.2	90.6	(75.9)	2,095.8
CPLE	(55.2)	151.8	32.6	59.2	(119.3)	(213.4)	(313.7)	(471.6)	(390.2)	(427.7)	(446.7)	107.6	(2,086.6)
CPLW	(74.4)	(69.6)	(33.8)	(57.9)	(69.0)	(60.9)	(73.8)	(74.0)	(71.7)	(76.0)	(73.7)	(74.6)	(809.3)
CWLP	(0.4)	0.0	(4.8)	0.0	0.0	0.0	0.0	0.0	(7.8)	0.0	0.0	0.0	(13.1)
DUK	83.2	574.2	345.2	115.8	75.8	(527.8)	(230.3)	(126.0)	(273.5)	(241.0)	(166.5)	362.5	(8.2)
EKPC	(140.8)	(78.1)	(208.8)	(122.4)	(146.5)	(132.8)	(131.0)	(90.5)	(63.9)	(100.3)	(107.2)	(124.9)	(1,447.2)
FE	(27.9)	17.8	(85.7)	41.9	29.5	(287.6)	(276.6)	(257.0)	(184.2)	(219.4)	(236.3)	(228.9)	(1,714.3)
IPL	(160.7)	(147.6)	(119.6)	(72.4)	9.2	(309.0)	(268.9)	(81.6)	(1.3)	30.5	238.9	94.1	(788.4)
LGEE	78.6	(1.7)	16.4	33.5	103.5	101.6	172.8	130.2	210.8	264.7	314.4	255.2	1,679.9
MEC	(257.6)	(270.4)	(280.1)	(387.3)	(347.1)	(275.1)	(342.4)	(291.4)	136.8	191.3	189.4	184.5	(1,749.4)
MECS	(89.7)	(12.8)	(55.8)	249.6	657.7	536.7	554.6	191.8	172.6	227.8	225.3	354.6	3,012.3
NEPT	(431.0)	(408.7)	(346.7)	(389.6)	(452.5)	(471.7)	(468.2)	(497.4)	(476.0)	(270.9)	(469.4)	(451.3)	(5,133.4)
NIPS	(62.2)	(103.7)	(85.6)	(37.0)	5.1	(87.1)	(85.4)	(83.9)	(27.3)	(60.2)	(50.1)	(56.4)	(733.8)
NYIS	(699.2)	(526.1)	(398.2)	(669.6)	(1,094.7)	(860.9)	(478.1)	(346.0)	(626.6)	(609.2)	(217.1)	(412.0)	(6,937.7)
OVEC	856.5	632.5	728.1	727.0	687.5	768.1	794.6	814.2	763.2	829.7	973.1	976.8	9,551.4
TVA	(431.9)	(133.4)	(207.5)	(237.6)	(514.2)	(401.0)	(336.8)	(268.8)	(256.8)	(97.5)	(180.8)	(57.1)	(3,123.2)
WEC	(101.7)	(116.1)	(98.8)	(74.6)	(55.7)	(133.4)	(69.7)	(70.6)	(47.4)	(60.7)	(53.1)	(57.6)	(939.4)
Total	(1,660.3)	(716.9)	(870.2)	(586.1)	(871.4)	(2,388.2)	(1,911.0)	(1,668.3)	(1,248.4)	(799.3)	(99.0)	695.2	(12,124.0)

Table 4-2 Real-time scheduled gross import volume by interface (GWh): Calendar year 2008

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
ALTE	0.1	0.0	0.0	0.0	1.1	0.0	0.0	0.0	10.2	0.6	0.6	54.6	67.2
ALTW	3.5	2.8	0.5	0.0	0.1	0.8	0.0	0.2	0.2	2.0	0.4	9.5	20.0
AMIL	86.6	96.8	104.7	155.0	129.5	42.0	31.4	47.2	61.8	41.4	28.1	67.7	892.2
CIN	590.3	400.9	609.6	731.4	791.4	637.0	356.3	479.6	315.2	277.4	303.3	257.7	5,750.1
CPLE	207.1	328.1	167.3	255.9	104.1	40.9	22.6	8.3	8.4	9.8	7.8	332.5	1,492.8
CPLW	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.1
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	358.1	679.3	523.4	385.8	347.6	74.4	209.8	188.9	151.5	118.3	201.9	533.5	3,772.5
EKPC	12.4	24.4	3.6	2.9	0.0	6.6	0.8	0.0	1.1	0.2	1.3	0.5	53.8
FE	153.5	200.1	98.9	260.5	294.3	32.6	31.6	40.8	46.3	42.2	22.4	31.6	1,254.8
IPL	0.9	79.0	4.9	20.7	45.4	24.0	4.0	23.8	80.5	70.1	258.8	164.4	776.5
LGEE	98.6	49.1	64.9	70.5	126.2	146.4	172.8	149.8	211.3	268.6	314.4	261.4	1,934.0
MEC	190.9	247.4	58.3	29.6	32.6	56.5	127.5	80.2	394.0	341.6	364.8	506.6	2,430.0
MECS	108.1	235.2	217.6	395.3	756.7	685.0	718.2	327.0	280.9	348.1	338.3	464.2	4,874.6
NEPT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NIPS	29.3	5.0	2.9	8.2	56.7	0.2	18.0	8.9	15.1	14.9	3.2	1.2	163.6
NYIS	1,026.5	991.6	1,131.3	1,039.6	1,091.2	1,085.4	1,530.0	1,429.8	969.5	852.4	1,204.7	1,145.8	13,497.8
OVEC	887.3	661.8	758.3	753.6	711.7	791.2	819.2	814.2	764.0	829.7	973.1	976.8	9,740.9
TVA	85.5	75.5	51.0	36.4	30.6	53.0	84.1	76.5	90.7	62.9	62.3	81.1	789.6
WEC	0.9	3.7	1.2	8.7	7.3	0.2	0.0	6.2	0.0	0.0	0.1	2.5	30.8
Total	3,839.6	4,080.7	3,798.4	4,154.1	4,526.5	3,676.3	4,126.3	3,681.4	3,400.7	3,280.2	4,085.5	4,891.6	47,541.3

Table 4-3 Real-time scheduled gross export volume by interface (GWh): Calendar year 2008

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
ALTE	178.9	144.9	131.7	136.0	100.3	161.6	151.7	127.2	134.0	123.7	77.3	86.3	1,553.6
ALTW	123.7	163.3	130.8	106.9	95.1	132.5	101.6	102.8	105.5	121.0	60.8	114.8	1,358.8
AMIL	114.6	84.0	111.0	146.7	138.1	119.0	125.0	96.0	35.1	23.9	20.9	32.1	1,046.4
CIN	409.2	333.2	408.6	261.5	229.2	300.7	367.6	346.9	217.9	233.2	212.7	333.6	3,654.3
CPLE	262.3	176.3	134.7	196.7	223.4	254.3	336.3	479.9	398.6	437.5	454.5	224.9	3,579.4
CPLW	74.4	69.6	33.8	57.9	69.0	61.0	73.8	74.0	71.7	76.0	73.7	74.6	809.4
CWLP	0.4	0.0	4.8	0.0	0.0	0.0	0.0	0.0	7.8	0.0	0.0	0.0	13.1
DUK	274.9	105.1	178.2	270.0	271.8	602.2	440.1	314.9	425.0	359.3	368.4	171.0	3,780.7
EKPC	153.2	102.5	212.4	125.3	146.5	139.4	131.8	90.5	65.0	100.5	108.5	125.4	1,501.0
FE	181.4	182.3	184.6	218.6	264.8	320.2	308.2	297.8	230.5	261.6	258.7	260.5	2,969.1
IPL	161.6	226.6	124.5	93.1	36.2	333.0	272.9	105.4	81.8	39.6	19.9	70.3	1,564.9
LGEE	20.0	50.8	48.5	37.0	22.7	44.8	0.0	19.6	0.5	3.9	0.0	6.2	254.1
MEC	448.5	517.8	338.4	416.9	379.7	331.6	469.9	371.6	257.2	150.3	175.4	322.1	4,179.4
MECS	197.8	248.0	273.4	145.7	99.0	148.3	163.6	135.2	108.3	120.3	113.0	109.6	1,862.3
NEPT	431.0	408.7	346.7	389.6	452.5	471.7	468.2	497.4	476.0	270.9	469.4	451.3	5,133.4
NIPS	91.5	108.7	88.5	45.2	51.6	87.3	103.4	92.8	42.4	75.1	53.3	57.6	897.4
NYIS	1,725.7	1,517.7	1,529.5	1,709.2	2,185.9	1,946.3	2,008.1	1,775.8	1,596.1	1,461.6	1,421.8	1,557.8	20,435.5
OVEC	30.8	29.3	30.2	26.6	24.2	23.1	24.6	0.0	0.8	0.0	0.0	0.0	189.5
TVA	517.4	208.9	258.5	274.0	544.8	454.0	420.9	345.3	347.5	160.4	243.1	138.2	3,912.8
WEC	102.6	119.8	100.0	83.3	63.0	133.6	69.7	76.8	47.4	60.7	53.2	60.1	970.2
Total	5,499.9	4,797.6	4,668.6	4,740.2	5,397.9	6,064.5	6,037.3	5,349.7	4,649.1	4,079.5	4,184.5	4,196.4	59,665.3

Table 4-4 Day-ahead net interchange volume by interface (GWh): Calendar year 2008

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
ALTE	(197.1)	(121.4)	(148.9)	(117.6)	(15.8)	203.2	409.9	293.3	229.9	(41.4)	(496.1)	(506.4)	(508.4)
ALTW	(918.9)	(944.3)	(1,045.9)	(843.5)	(475.8)	(818.5)	(548.0)	(456.0)	(403.3)	(699.5)	(765.2)	(766.1)	(8,685.0)
AMIL	221.6	273.1	454.3	449.9	173.7	116.0	68.1	33.3	(4.7)	191.0	170.3	115.0	2,261.6
CIN	(148.8)	(172.1)	(238.4)	(197.8)	(44.2)	(180.7)	(223.6)	76.5	(195.4)	(264.3)	(171.4)	(240.9)	(2,001.2)
CPLE	(70.1)	24.0	(63.5)	(55.1)	(13.6)	(106.7)	(99.3)	(84.2)	(97.1)	(52.6)	(36.9)	61.2	(594.0)
CPLW	(186.0)	(174.0)	(88.3)	(150.0)	(180.3)	(154.7)	(186.0)	(186.1)	(180.0)	(186.0)	(183.5)	(183.6)	(2,038.3)
CWLP	(6.8)	(0.4)	(4.8)	0.0	0.0	0.0	0.0	0.0	(0.1)	(0.2)	(0.0)	0.0	(12.3)
DUK	130.9	277.0	109.4	20.6	62.1	(194.8)	(90.5)	(17.3)	(8.7)	(86.9)	(69.0)	106.6	239.3
EKPC	(27.6)	(38.5)	(37.2)	(36.0)	(37.2)	(36.0)	(38.4)	(37.3)	(36.0)	(37.2)	(36.0)	(76.0)	(473.3)
FE	(119.6)	(114.7)	(153.7)	(98.8)	(156.3)	(226.8)	(216.7)	(205.9)	(155.0)	(139.0)	(124.9)	(155.7)	(1,867.0)
IPL	(49.7)	(77.0)	(129.0)	(170.3)	(44.7)	(104.1)	(115.3)	(86.7)	(58.4)	(212.0)	34.5	(58.9)	(1,071.7)
LGEE	(44.6)	(33.2)	(14.0)	(10.3)	1.6	(27.8)	(13.6)	(0.6)	0.0	(0.9)	6.6	2.0	(134.8)
MEC	(154.6)	(126.2)	(120.6)	(255.6)	(233.5)	(282.6)	(283.5)	(278.6)	(154.4)	(132.1)	(144.9)	(91.4)	(2,258.1)
MECS	(91.0)	(262.2)	(405.4)	(334.4)	167.2	(164.7)	55.1	97.4	197.4	99.2	(112.6)	(110.1)	(864.1)
NEPT	(426.2)	(400.3)	(344.0)	(381.5)	(442.1)	(478.0)	(474.7)	(498.1)	(483.7)	(300.6)	(470.0)	(469.8)	(5,169.0)
NIPS	(728.3)	(762.9)	(545.3)	(394.8)	(344.6)	(595.3)	(609.0)	(602.4)	(528.8)	(515.5)	(325.3)	(207.0)	(6,159.4)
NYIS	(31.1)	(129.9)	(74.8)	(134.1)	(236.6)	(162.2)	(205.7)	(329.2)	(52.4)	(15.0)	69.6	(29.6)	(1,331.0)
OVEC	1,052.7	893.6	957.6	894.7	786.0	712.0	787.4	788.7	717.2	773.7	694.0	696.9	9,754.6
TVA	(35.5)	240.7	53.4	57.4	(75.2)	(81.3)	(5.2)	(2.5)	(47.0)	42.3	278.7	387.5	813.2
WEC	(77.1)	(35.5)	(72.0)	(24.3)	(62.9)	(73.8)	(75.9)	(58.8)	(38.5)	(56.8)	(50.9)	(57.6)	(684.3)
Total	(1,907.8)	(1,684.3)	(1,911.0)	(1,781.8)	(1,172.3)	(2,656.9)	(1,864.9)	(1,554.5)	(1,299.0)	(1,633.8)	(1,733.3)	(1,583.9)	(20,783.4)

Table 4-5 Day-ahead gross import volume by interface (GWh): Calendar year 2008

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
ALTE	68.6	26.9	51.4	147.3	194.4	544.5	1,104.2	1,282.8	1,073.2	635.5	290.3	318.1	5,737.3
ALTW	171.2	246.0	314.8	353.2	233.5	83.8	201.1	82.2	109.2	182.8	46.5	25.1	2,049.5
AMIL	238.0	286.8	463.7	460.2	181.1	120.7	72.6	33.4	2.9	195.9	180.0	118.7	2,354.0
CIN	37.5	25.3	22.1	7.0	65.8	57.3	59.9	138.0	51.3	41.3	50.4	89.3	645.3
CPLE	49.9	115.2	32.0	60.3	86.4	21.6	25.5	44.4	30.4	61.5	79.3	167.5	773.9
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.2
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	184.4	302.7	133.5	136.1	118.9	6.9	77.0	63.3	67.0	26.0	79.5	178.1	1,373.4
EKPC	0.0	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.2
FE	28.8	16.1	6.3	43.7	28.3	9.3	20.9	24.3	8.6	45.7	43.1	14.9	289.9
IPL	14.0	127.8	64.8	61.3	54.6	91.3	87.4	76.5	232.1	170.9	291.9	184.1	1,456.7
LGEE	13.6	31.2	12.7	19.2	1.6	1.3	0.4	1.1	0.0	0.0	6.6	2.0	89.7
MEC	46.6	73.8	0.0	0.0	3.4	0.0	48.5	0.0	67.8	0.0	3.7	159.0	402.7
MECS	256.3	164.4	154.6	187.0	311.4	273.9	454.4	536.0	561.0	567.1	386.4	349.7	4,202.2
NEPT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NIPS	92.1	29.7	14.3	11.7	39.6	37.3	6.7	71.1	171.3	227.6	308.3	344.8	1,354.6
NYIS	883.3	762.9	823.4	804.8	805.5	877.9	1,017.1	157.7	1,012.9	888.1	956.4	879.1	9,869.1
OVEC	1,062.9	932.8	998.9	903.2	790.1	742.0	854.8	852.6	744.6	790.4	703.6	707.3	10,083.2
TVA	149.4	290.5	128.7	95.7	127.1	9.7	37.2	26.1	4.5	84.9	377.4	413.6	1,744.8
WEC	30.0	80.8	19.7	39.3	6.1	4.8	2.5	7.2	1.3	4.7	4.4	0.0	200.7
Total	3,326.7	3,513.9	3,240.9	3,330.1	3,047.7	2,882.3	4,070.2	3,396.7	4,138.1	3,922.5	3,807.8	3,951.5	42,628.5

Table 4-6 Day-ahead gross export volume by interface (GWh): Calendar year 2008

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
ALTE	265.7	148.3	200.4	265.0	210.3	341.3	694.3	989.5	843.2	676.9	786.4	824.5	6,245.7
ALTW	1,090.2	1,190.3	1,360.7	1,196.7	709.3	902.3	749.1	538.2	512.5	882.3	811.8	791.2	10,734.5
AMIL	16.3	13.7	9.3	10.4	7.5	4.7	4.5	0.1	7.6	4.9	9.7	3.7	92.4
CIN	186.3	197.4	260.5	204.8	110.0	238.0	283.5	61.5	246.7	305.7	221.9	330.2	2,646.5
CPLE	120.1	91.2	95.5	115.4	100.0	128.3	124.8	128.6	127.5	114.1	116.2	106.3	1,368.0
CPLW	186.0	174.0	88.3	150.0	180.3	154.7	186.0	186.1	180.0	186.0	183.5	183.8	2,038.5
CWLP	6.8	0.4	4.8	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.0	0.0	12.3
DUK	53.5	25.7	24.1	115.5	56.8	201.7	167.5	80.6	75.7	112.9	148.5	71.5	1,134.1
EKPC	27.6	39.6	37.2	36.0	37.2	36.0	38.4	37.3	36.0	37.2	36.0	76.0	474.4
FE	148.4	130.8	160.0	142.5	184.5	236.1	237.6	230.2	163.6	184.7	168.0	170.6	2,156.9
IPL	63.7	204.8	193.8	231.6	99.3	195.4	202.7	163.2	290.5	382.9	257.4	243.0	2,528.4
LGEE	58.2	64.4	26.7	29.5	0.0	29.1	14.0	1.7	0.0	0.9	0.0	0.0	224.5
MEC	201.2	200.0	120.6	255.6	236.9	282.6	332.0	278.6	222.2	132.1	148.6	250.4	2,660.8
MECS	347.2	426.6	560.0	521.4	144.2	438.6	399.3	438.6	363.6	467.9	499.0	459.8	5,066.4
NEPT	426.2	400.3	344.0	381.5	442.1	478.0	474.7	498.1	483.7	300.6	470.0	469.8	5,169.0
NIPS	820.4	792.6	559.6	406.5	384.2	632.6	615.7	673.5	700.1	743.1	633.7	551.8	7,514.0
NYIS	914.4	892.8	898.2	938.9	1,042.2	1,040.1	1,222.8	486.9	1,065.3	903.1	886.8	908.7	11,200.1
OVEC	10.3	39.2	41.3	8.5	4.0	30.0	67.4	63.9	27.4	16.7	9.6	10.4	328.6
TVA	184.9	49.8	75.3	38.3	202.3	91.0	42.4	28.6	51.5	42.6	98.7	26.1	931.6
WEC	107.2	116.3	91.7	63.6	69.0	78.6	78.4	66.0	39.8	61.5	55.3	57.6	885.0
Total	5,234.5	5,198.2	5,151.9	5,111.9	4,220.0	5,539.2	5,935.1	4,951.2	5,437.1	5,556.2	5,541.1	5,535.4	63,411.8

Interface Pricing

Interface pricing points differ from interfaces. (See Table 4-7 for a list of active interfaces in 2008. Figure 4-4 shows the approximate geographic location of the interfaces).

Transactions can be scheduled to an interface based on a contract transmission path, but pricing points are developed and applied based on the estimated electrical impact of the external power source on PJM tie lines, regardless of contract transmission path.[15] PJM establishes prices for transactions with external balancing authorities by assigning interface pricing points to individual balancing authorities based on the Generation Control Area (GCA) and Load Control Area (LCA) as specified on the NERC Tag. Interface pricing points are designed to reflect the way a transaction from or to an external area actually impacts PJM electrically for areas that are both adjacent to, and not adjacent to, PJM. However, this analysis is an approximation given the complexity of the transmission network outside PJM and the dynamic nature of power flows. Transactions between PJM and external balancing authorities need to be priced at the PJM border. A set of external buses is used to create such interface prices. The challenge is to create an interface price, composed

15 See PJM. "LMP Aggregate Definitions" (December 18, 2008) (Accessed January 13, 2009) <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/20081218-aggregate-definitions.ashx> (1MB). PJM periodically updates these definitions on its Web site. See <http://www.pjm.com>.

of external pricing points, that accurately represents flows between PJM and external sources of energy and, therefore, to create price signals that embody underlying economic fundamentals.[16] Table 4-8 presents the interface pricing points used during 2008.

Table 4-7 Active interfaces: Calendar year 2008

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
ALTE	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
ALTW	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
AMIL	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CIN	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CPLE	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CPLW	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CWLP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
DUK	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
EKPC	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
FE	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
IPL	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
LGEE	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
MEC	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
MECS	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NEPT	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NIPS	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NYIS	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
OVEC	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
TVA	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
WEC	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active

16 See the *2007 State of the Market Report*, Volume II, Appendix D, "Interchange Transactions," for a more complete discussion of the development of pricing points.

Figure 4-4 PJM's footprint and its external interfaces

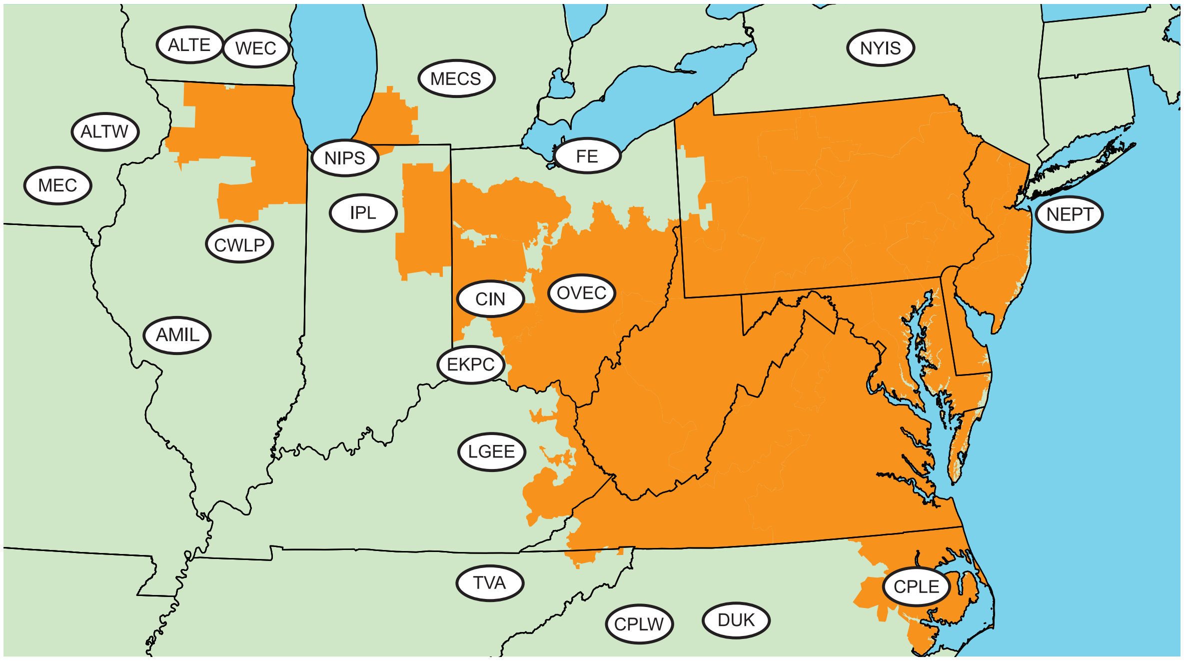


Table 4-8 Active pricing points: Calendar year 2008

PJM 2008 Pricing Points				
MICHFE	MISO	NEPT	NIPSCO	Northwest
NYIS	Ontario IESO	OVEC	SOUTHEXP	SOUTHIMP

Interactions with Bordering Areas

PJM Interface Prices with Organized Markets

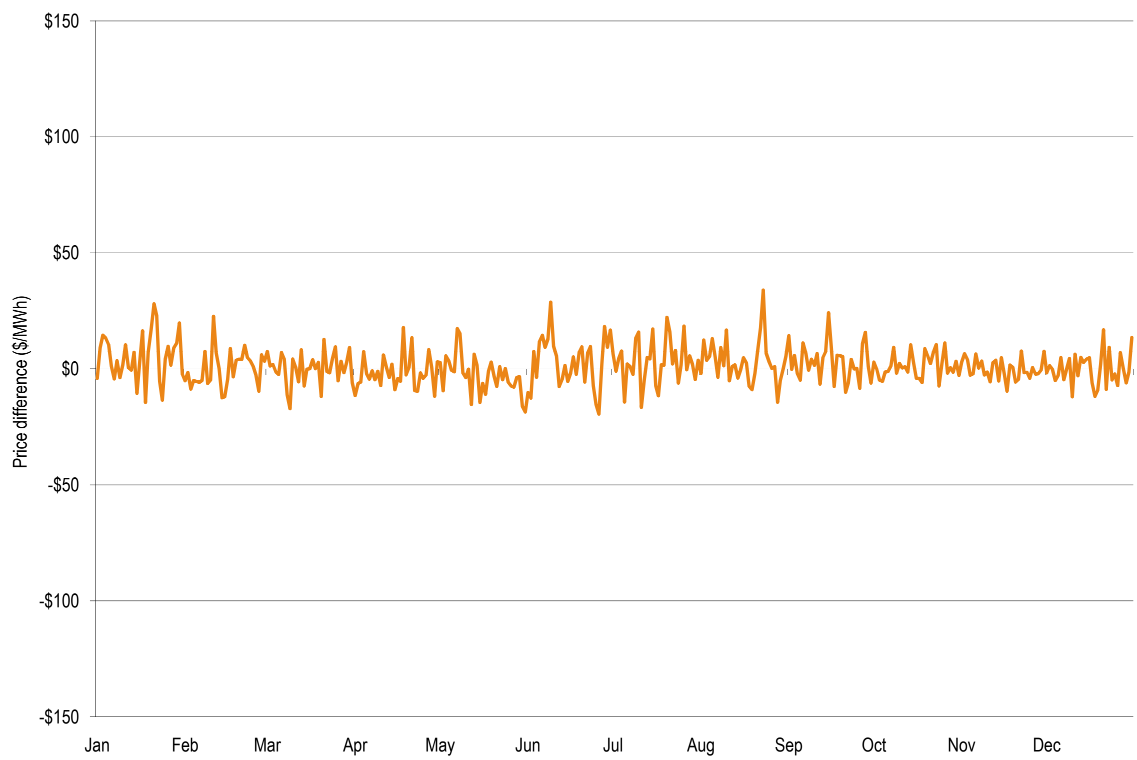
During 2008, Real-Time Market prices at the borders between PJM and the Midwest ISO and between PJM and the NYISO were consistent with competitive forces.

PJM and Midwest ISO Interface Prices

On April 1, 2005, with the introduction of price-based markets, the Midwest ISO created a new interface pricing point with PJM. Both the PJM/MISO and the MISO/PJM pricing points represent the value of power at the relevant border, as determined by each market. In both cases, the interface price is the price at which transactions are settled. For example, a transaction into PJM from Midwest ISO would receive the PJM/MISO price upon entering PJM, while a transaction into Midwest ISO from PJM would receive the MISO/PJM price when entering Midwest ISO. PJM and Midwest ISO use network models to determine these prices and to ensure that the prices are consistent with the underlying electrical flows. PJM uses the LMP at nine buses[17] within Midwest ISO to calculate the PJM/MISO Interface price, while Midwest ISO uses all of the PJM generator buses in its model of the PJM system in its computation of the MISO/PJM Interface price.[18]

The 2008 real-time hourly average interface prices for PJM/MISO and MISO/PJM were $49.80 and $50.97, respectively. The simple average difference between the real-time MISO/PJM interface price and the PJM/MISO Interface price was $1.17 in 2008, 2 percent of the average PJM/MISO price. (See Figure 4-5.) The real-time MISO/PJM interface price was slightly higher on average than the PJM/MISO price in 2008.

Figure 4-5 Real-time daily hourly average price difference (Midwest ISO Interface minus PJM/MISO): Calendar year 2008



The simple average interface price difference does not reflect the underlying hourly variability in prices. There are a number of relevant measures of variability, including the number of times the price differential fluctuates between positive and negative, the standard deviation of individual prices and of price differences and the absolute value of the price differences.

During 2008, the difference between the real-time PJM/MISO Interface price and the real-time MISO/PJM Interface price fluctuated between positive and negative about ten times per day. The standard deviation of the hourly price was $31.61 for the PJM/MISO price and $35.09 for the MISO/

17 See PJM. "LMP Aggregate Definitions" (December 18, 2008) (Accessed January 13, 2009) <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/20081218-aggregate-definitions.ashx> (1MB). PJM periodically updates these definitions on its Web site. See <http://www.pjm.com>.

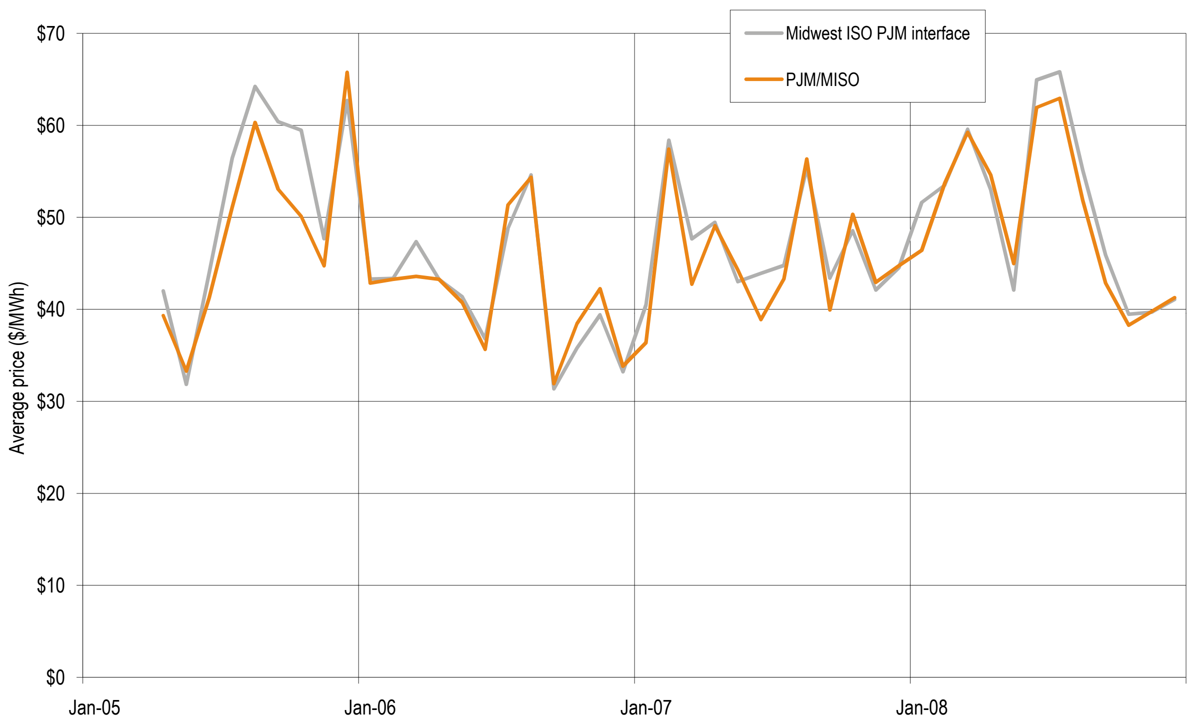
18 Based on information obtained from the Midwest ISO Extranet (January 13, 2009) <http://extranet.midwestiso.org>.

PJM Interface price. The standard deviation of the difference in interface prices was $26.53. The average of the absolute value of the hourly price difference was $16.95. Absolute values reflect price differences regardless of whether they are positive or negative.

Several factors are responsible for the relationship between interface prices. The simple average interface price difference suggests that competitive forces prevent price deviations from persisting, an observation further supported by the frequency with which price differential switches between positive and negative.

In addition, there is a significant correlation between monthly average hourly PJM and Midwest ISO interface prices during the 2008 period. Figure 4-6 shows this correlation between hourly PJM and Midwest ISO interface prices.

Figure 4-6 Real-time monthly hourly average Midwest ISO PJM interface price and the PJM/MISO price: April 2005 to 2008



The difference in real-time PJM and MISO interface prices can also be measured by comparing the LMP for pairs of generating units that are located close together but on opposite sides of the border between PJM and the Midwest ISO and by comparing the LMP for jointly owned units that participate in both markets. The MMU compared two pairs of units and two jointly owned units. The LMP differences were compared over four time periods: calendar year 2006, January through May 2007 (i.e., the pre-marginal loss implementation period), June through December 2007 (i.e., the post-marginal loss implementation period) and calendar year 2008.

Table 4-9 shows that in 2006 all of the unit pairs and jointly owned units had real-time LMP differences larger than the difference at the PJM/MISO Interface. After the implementation of marginal losses in PJM, most units showed decreases in their real-time LMP differences while also moving closer to the difference observed at the interface. While the sample is not adequate to permit general conclusions, the data from these units indicate that actual price differences at the border between PJM and the Midwest ISO have varied from the interface pricing differences. Price differences at Kincaid reflect actual operational issues that make the price adjustment process less continuous.

Table 4-9 Average real-time LMP difference (PJM minus Midwest ISO): January 1, 2006, through December 31, 2008

	2006	2007 (Pre-Marginal Losses)	2007 (Post-Marginal Losses)	2008
Kincaid (PJM) & Coffeen (MISO)	$5.87	$4.31	$5.76	$8.26
Beaver Valley (PJM) & Mansfield (MISO)	$2.28	($2.64)	$0.55	$0.89
Miami Fort (PJM) & (MISO)	$1.95	($1.30)	($0.95)	$1.25
Stuart (PJM) & (MISO)	$2.09	($0.81)	($0.64)	$0.85
PJM/MISO Interface	($0.23)	($1.83)	($0.85)	($0.76)

PJM and NYISO Interface Prices

If interface prices were defined in a comparable manner by PJM and NYISO, if identical rules governed external transactions in PJM and NYISO, if time lags were not built into the rules governing such transactions and if no risks were associated with such transactions, then prices at the interfaces would be expected to be very close and the level of transactions would be expected to be related to any price differentials. The fact that none of these conditions exists is important in explaining the observed relationship between interface prices and inter-ISO power flows, and those price differentials.[19]

PJM operators must verify all requested energy schedules with its neighboring balancing authorities. Only if the neighboring balancing authority agrees with the expected interchange will the transaction flow. If there is a disagreement in the expected interchange for any 15 minute interval, the system operators must work to resolve the difference. It is important that both balancing authorities enter the same values in their Energy Management Systems (EMS) to avoid inadvertent energy from flowing between balancing authorities.

With the exception of the NYISO, all neighboring balancing authorities handle transaction requests the same way as PJM (i.e. via the NERC Tag). This helps facilitate interchange transaction checkouts, as all balancing authorities are receiving the same information. While the NYISO also requires NERC Tags, they utilize their Market Information System (MIS) as their primary scheduling tool. The MIS evaluates all bids and offers each hour, and performs a least cost economic dispatch solution. This evaluation accepts or denies individual transactions in whole or in part. Upon market clearing, the NYISO implements NERC Tag adjustments to match the output of the MIS. PJM and the NYISO can verify interchange transactions once the NYISO Tag adjustments are sent and approved. The results of the adjustments made by the NYISO affect PJM operations, as the

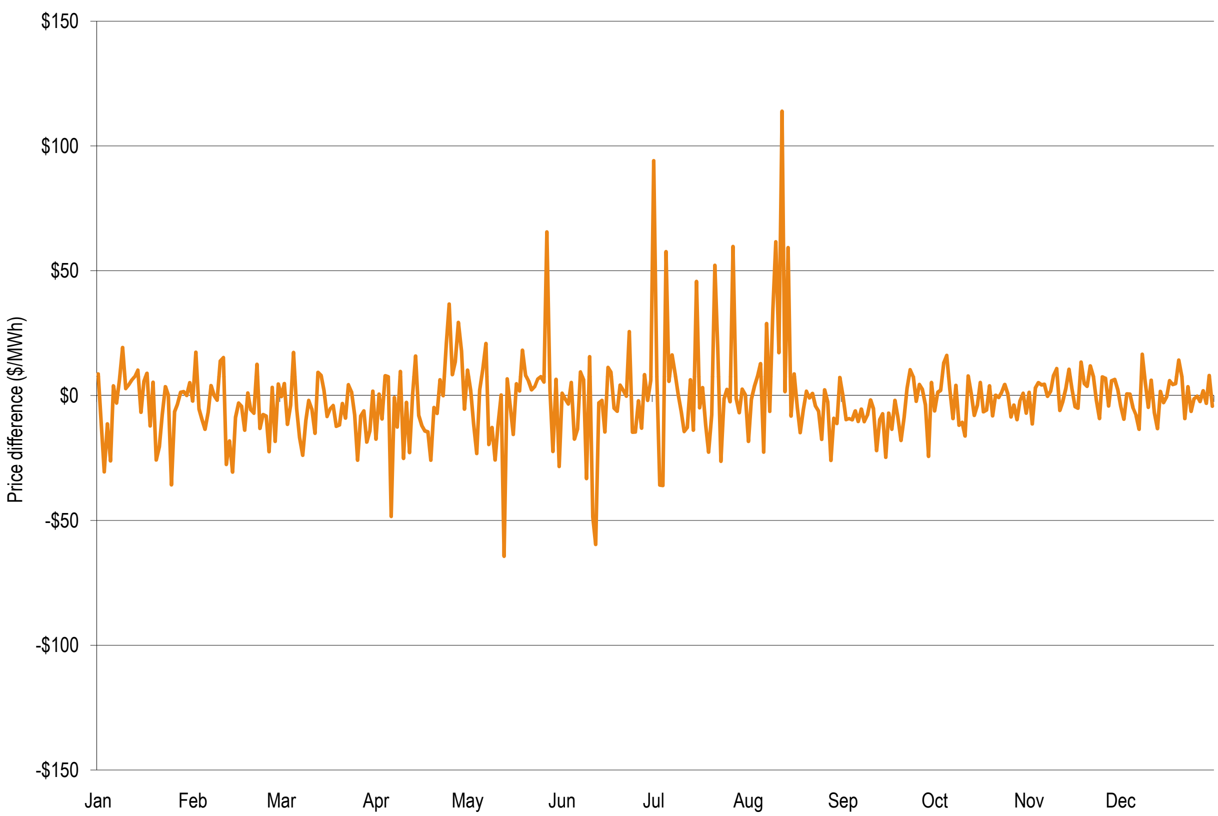
19 See also the discussion of these issues in the *2005 State of the Market Report*, Section 4, "Interchange Transactions" (March 8, 2006).

adjustments often cause large swings in expected ramp for the next hour (as discussed in the "Ramp" section).

PJM's price for transactions with NYISO, termed the NYIS pricing point by PJM, represents the value of power at the PJM-NYISO border, as determined by the PJM market. PJM defines its NYIS pricing point using two buses.[20] Similarly, the NYISO's price for transactions with PJM, termed the PJM proxy bus by the NYISO, represents the value of power at the NYISO-PJM border, as determined by the NYISO market. In the NYISO market, transactions are required to have a price associated with them. Import transactions are treated as generator offers at the NYISO/PJM proxy bus. Export transactions are treated as load bids. Competing bids and offers are evaluated along with the other NYISO resources and a proxy bus price is derived.

The 2008 real-time hourly average price for PJM/NYIS and the NYISO/PJM proxy bus price were $71.99 and $72.86, respectively. The simple average difference between the PJM/NYIS Interface price and the NYISO/PJM proxy bus price decreased from -$4.07 per MWh in 2007 to $0.86 per MWh in 2008, and the variability of the difference also decreased. (See Figure 4-7.) PJM's net export volume to New York for 2008 was significantly higher than in 2007. This is consistent with the fact that the PJM/NYIS price was, on average, lower than the NYISO/PJM price in 2008.

Figure 4-7 Real-time daily hourly average price difference (NY proxy - PJM/NYIS): Calendar year 2008



20 See PJM. "LMP Aggregate Definitions" (December 18, 2008) (Accessed January 13, 2009) <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/20081218-aggregate-definitions.ashx> (1MB). PJM periodically updates these definitions on its Web site. See <http://www.pjm.com>.

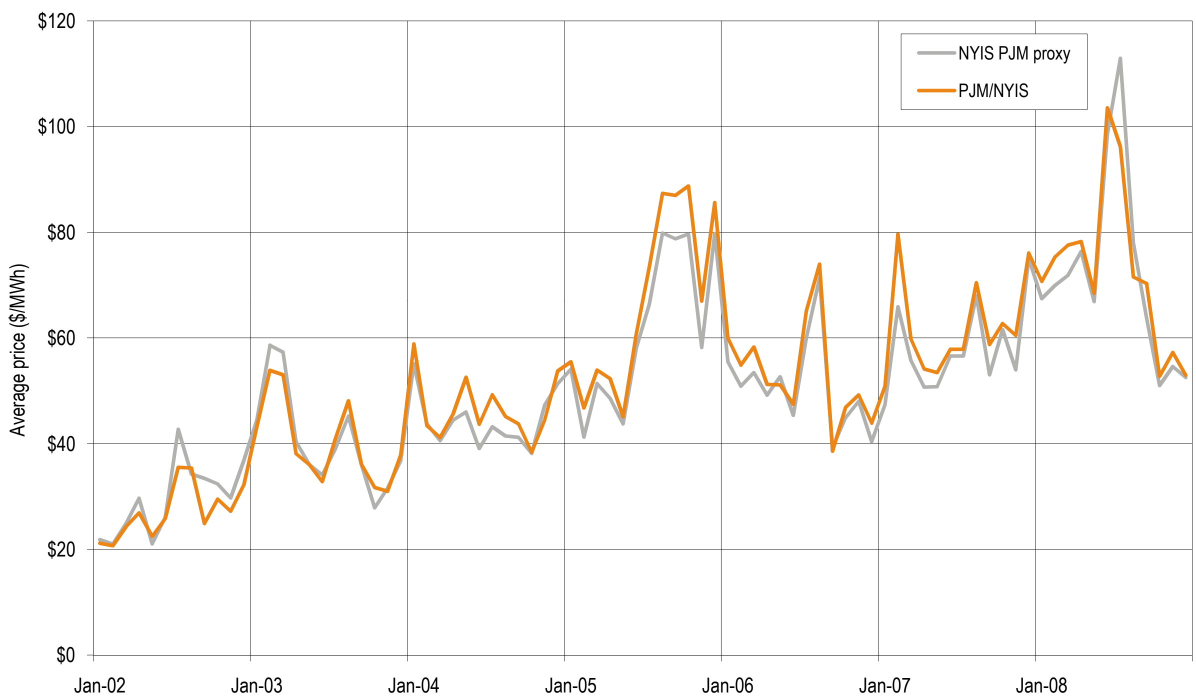
The simple average interface price difference does not reflect the underlying hourly variability in prices. There are a number of relevant measures of variability, including the number of times the price differential fluctuates between positive and negative, the standard deviation of individual prices and of price differences and the absolute value of the price differences.

The difference between the real-time PJM/NYIS interface price and the real-time NYISO/PJM price continued to fluctuate between positive and negative about eight times per day during 2008 as it has since 2003. The standard deviation of hourly price was $39.97 in 2008 for the PJM/NYIS price and $33.14 in 2008 for the NYISO/PJM proxy bus price. The standard deviation of the difference in interface prices was $48.53 in 2008. The average of the absolute value of the hourly price difference was $23.74 in 2008. Absolute values reflect price differences without regard to whether they are positive or negative.

A number of factors are responsible for the observed relationship between interface prices. The fact that the simple average of interface price differences is relatively small suggests that competitive forces prevent price deviations from persisting. That is further supported by the frequency with which the price differential switches between positive and negative. However, continuing significant variability in interface prices is consistent with the fact that interface prices are defined and established differently, making it difficult for prices to equalize, regardless of other factors.[21]

There has been a significant correlation between real-time monthly average hourly PJM and NYISO interface prices during the entire period 2002 to 2008. Figure 4-8 shows this correlation between hourly PJM and NYISO interface prices.

Figure 4-8 Real-time monthly hourly average NYISO/PJM proxy bus price and the PJM/NYIS price: Calendar years 2002 to 2008

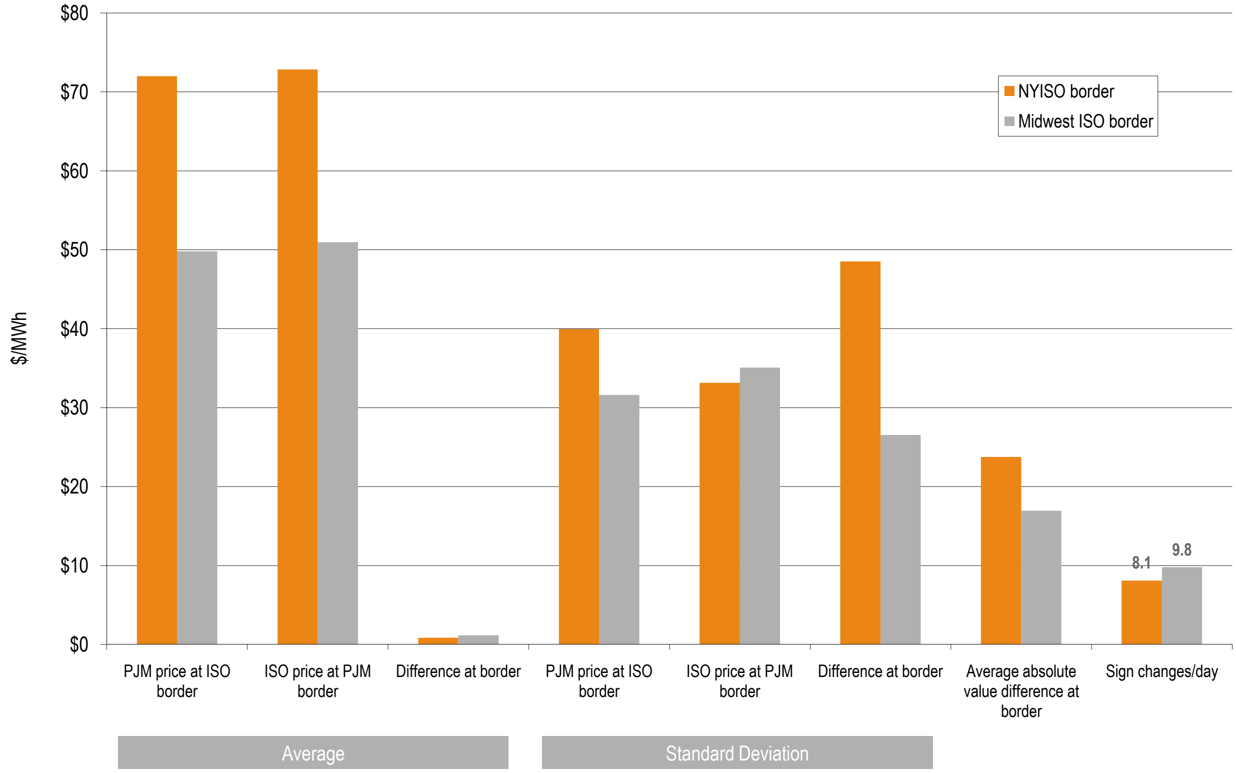


21 As previously noted, institutional difference between PJM and NYISO markets partially explains observed differences in border prices. For a description of those differences, see the *2005 State of the Market Report*, Appendix D, "Interchange Transactions" (March 8, 2006), pp. 195-198.

Summary of Interface Prices between PJM and Organized Markets

The key features of PJM interface pricing with the Midwest ISO and with the NYISO are summarized and compared in Figure 4-9, including average prices and measures of variability.

Figure 4-9 PJM, NYISO and Midwest ISO real-time border price averages: Calendar year 2008



Operating Agreements with Bordering Areas

To improve reliability and reduce potential competitive seams issues, PJM and its neighbors have developed, and continue to work on, joint operating agreements. These agreements are in various stages of development and include a reliability agreement with NYISO, an implemented operating agreement with Midwest ISO, an implemented reliability agreement with TVA, an operating agreement with Progress Energy Carolinas, Inc., that is not yet fully implemented, and a reliability coordination agreement with VACAR South.

PJM and New York Independent System Operator Joint Operating Agreement (JOA)

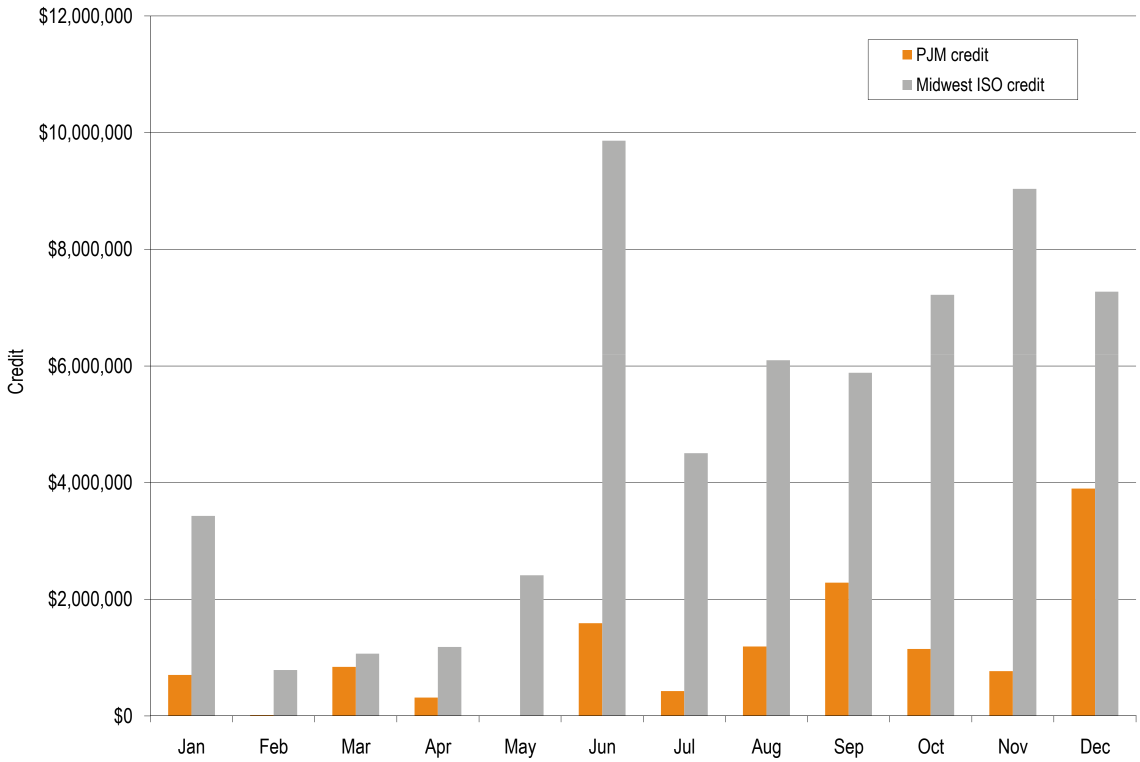
On May 22, 2007, the JOA between PJM and NYISO became effective. This agreement was developed to improve reliability, and includes obligations concerning: maintaining interconnected operations, voltage control and reactive power; coordinating scheduled outages and transmission planning; and providing emergency assistance. It also formalizes the process of electronic checkout of schedules, the exchange of interchange schedules to facilitate calculations for ATC and standards for interchange revenue metering. This agreement references and confirms earlier PJM/NYISO agreements, protocols and procedures. These remain in effect. This agreement does not include provisions for market-based congestion management or other market-to-market activity. The MMU recommends that PJM and NYISO develop market-based congestion management protocols as soon as practicable.

PJM and Midwest ISO Joint Operating Agreement (JOA)

The market-to-market coordination between PJM and MISO continued in 2008. Under the market-to-market rules, the organizations coordinate pricing at their borders. PJM and the Midwest ISO each calculate a locational marginal price (LMP) for its interface with the other organization. Both entities calculate LMPs using network models including distribution factor impacts. PJM uses nine buses within the Midwest ISO to calculate the PJM/MISO pricing point LMP while the Midwest ISO uses all of the PJM generator buses in its model of the PJM system in its computation of the MISO/PJM pricing point.

In 2008, the market-to-market operations resulted both in Midwest ISO and PJM redispatching units to control congestion in the other's area and in the exchange of payments for this redispatch. Figure 4-10 presents the monthly credits each organization received from redispatching for the other. A PJM credit is a payment by the Midwest ISO to PJM and a Midwest ISO credit is a payment by PJM to the Midwest ISO. The largest payments from PJM to Midwest ISO during the year were the result of redispatch by Midwest ISO to relieve congestion on the East Frankfort – Crete 345 kV for loss of Dumont – Wilton Center 765 kV line. Market-to-market activity on this line in 2008 was primarily due to line outages caused by tornados in May and June. Total PJM payments to Midwest ISO were $54.2 million, a 107 percent increase from the 2007 level. The largest payments from Midwest ISO to PJM during the year were the result of redispatch by PJM to relieve congestion on the Rising 345/138 XFMR 1 for the loss of Clinton – Brokaw 345 kV line. Total Midwest ISO payments to PJM were $8.6 million, a 64 percent decrease from the 2007 level.

Figure 4-10 Credits for coordinated congestion management: Calendar year 2008



PJM, Midwest ISO and TVA Joint Reliability Coordination Agreement

The Joint Reliability Coordination Agreement (JRCA) executed on April 22, 2005, provides for comprehensive reliability management and congestion relief among the wholesale electricity markets of the Midwest ISO and PJM and the service territory of TVA. The agreement continued to be in effect during 2008. Information-sharing among the parties enables each transmission provider to recognize and manage the effects of its operations on the adjoining systems. Additionally, the three organizations conduct joint planning sessions to ensure that improvements to their integrated systems are undertaken in a cost-effective manner and without adverse reliability impacts on any organization's customers.

PJM and Progress Energy Carolinas, Inc. Joint Operating Agreement

On September 9, 2005, the FERC approved a JOA between PJM and Progress Energy Carolinas, Inc. (PEC), with an effective date of July 30, 2005. The agreement remains in effect. Since Progress Energy Carolinas is not a market system, the coordination agreement between PEC and PJM is similar to the agreement that existed between the Midwest ISO and PJM during the first phase of their JOA. The ATC coordination that had been expected to be completed during the first half of 2006 remained under development during 2008. PJM and Progress continued to develop the congestion management process as required by the agreement. A phased approach to development of congestion management is being discussed.

PJM and VACAR South Reliability Coordination Agreement

On May 23, 2007, PJM and VACAR South (comprised of Duke Energy Carolinas, LLC (DUK), Progress Energy Carolinas, Inc. (PEC), South Carolina Public Service Authority (SCPSA), Southeast Power Administration (SEPA), South Carolina Energy and Gas Company (SCE&G) and Yadkin Inc. (a part of Alcoa)) entered into a reliability coordination agreement. This agreement was developed to augment and further support reliability. It provides for system and outage coordination, emergency procedures and the exchange of data. This arrangement permits each party to coordinate its plans and operations in the interest of reliability. Provisions are also made for making regional studies and recommendations to improve the reliability of the interconnected bulk power systems.

Other Agreements with Bordering Areas

Con Edison and PSE&G Wheeling Contracts

To help meet the demand for power in New York City, Con Edison uses electricity generated in upstate New York and wheeled through New York and New Jersey. A common path is through Westchester County using lines controlled by NYISO. Another path is through northern New Jersey using lines controlled by PJM. This wheeled power creates loop flow across the PJM system. The Con Edison/PSE&G contracts governing the New Jersey path evolved during the 1970s and were the subject of a Con Edison complaint to the FERC in 2001. In May 2005, the FERC issued an order setting out a protocol developed by the two companies, PJM and NYISO.[22] In July 2005, the protocol was implemented. Con Edison filed a protest with the FERC regarding the delivery performance in January 2006.[23]

PJM continued to operate under the terms of the protocol during 2008 while continuing to pursue work on the 19 items identified in the work plan to improve protocol performance. In August, 2007 the FERC denied a rehearing request on Con Edison's complaints regarding protocol performance and refunds.[24]

The protocol allows Con Edison to elect up to the flow specified in each contract through the PJM Day-Ahead Energy Market. These elections are transactions in the PJM Day-Ahead Energy Market. The 600 MW contract is for firm service and the 400 MW contract has a priority higher than non-firm service but less than firm service. These elections obligate PSE&G to pay congestion costs associated with the daily elected level of service under the 600 MW contract and obligate Con Edison to pay congestion costs associated with the daily elected level of service under the 400 MW contract. The interface prices for this transaction are not defined PJM interface prices, but are defined in the protocol based on the actual facilities governed by the protocol.

Under the FERC order, PSE&G is assigned FTRs associated with the 600 MW contract. The PSE&G FTRs are treated like all other FTRs. In 2008, PSE&G's FTR revenues were less than its congestion charges by $26,250 after adjustments (Revenues were approximately $14,250 less than charges in 2007.) Under the FERC order, Con Edison receives credits on an hourly basis for

22 111 FERC ¶ 61,228 (2005).
23 Protest of the Consolidated Edison Company of New York, Inc., Protest, Docket No. EL02-23 (January 30, 2006).
24 FERC Order Denying Rehearing, Order, Docket No. EL02-23 (August 15, 2007).

its elections under the 400 MW contract from a pool containing any excess congestion revenue after hourly FTRs are funded. In 2008, Con Edison's congestion credits were $268,368 less than its day-ahead congestion charges. Con Edison also had negative day-ahead congestion charges, with the result that Con Edison's total credits exceeded its congestion charges by $213,535. (Credits had been approximately $1.7 million less than charges in 2007.) (See Table 4-10.)

In effect, Con Edison has been given congestion credits that are the equivalent of a class of FTRs covering positive congestion with subordinated rights to revenue. However, Con Edison is not treated as having an FTR when congestion is negative. An FTR holder in that position would pay the negative congestion credits, but Con Edison does not. The protocol's provisions about congestion payments clearly cover congestion charges and offsetting congestion credits, but are not explicit on the treatment of Con Edison's negative congestion credits, which were $213,535 in 2008. The parties should address this issue.

Table 4-10 Con Edison and PSE&G wheeling settlement data: Calendar year 2008

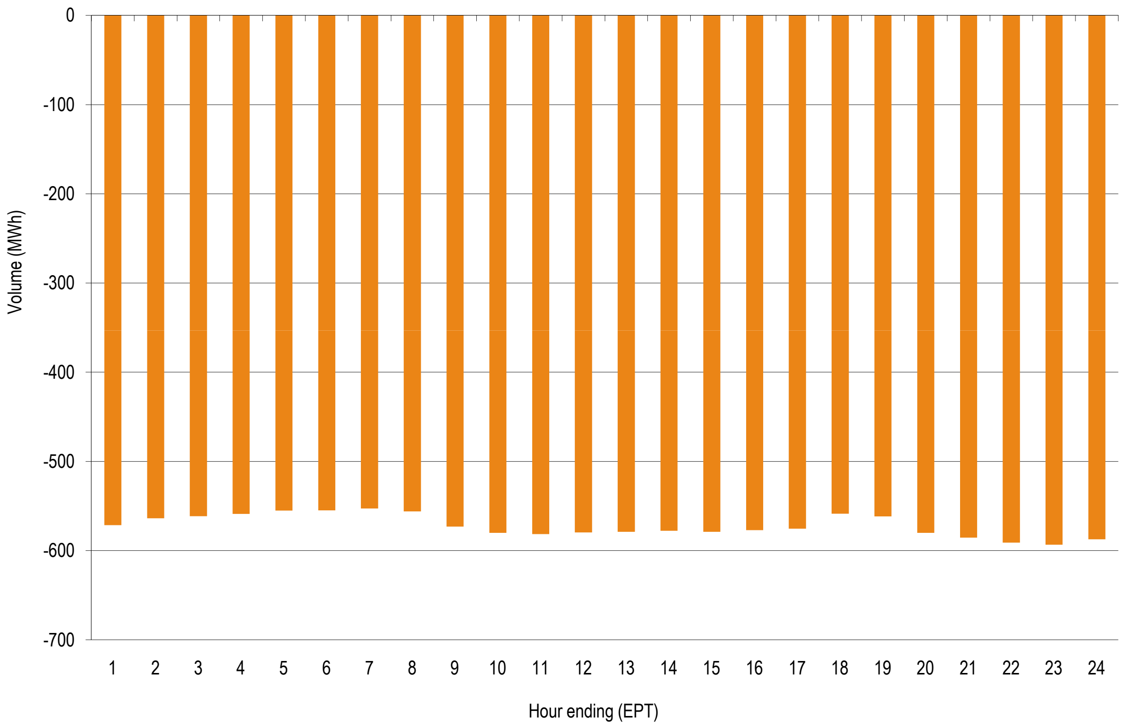
	Con Edison			PSE&G		
	Day Ahead	Balancing	Total	Day Ahead	Balancing	Total
Total Congestion Credit	$4,061,370	($71,943)	$3,989,426	$6,425,449	($40,018)	$6,385,431
Congestion Credit			$3,793,002			$6,405,281
Adjustments			($17,110)			($6,082)
Net Charge			$213,535			($13,768)

Under the terms of the protocol, Con Edison can make a real-time election of its desired flow for each hour in the Real-Time Energy Market. If this election differs from its day-ahead schedule, the company is subject to the resultant charges or credits. This occurred in 5 percent of the hours in 2008.

Neptune Underwater Transmission Line to Long Island, New York

On July 1, 2007, a 65-mile, DC transmission line from Sayreville, New Jersey, to Nassau County on Long Island via undersea and underground cable was placed in service. This is a merchant 230 kV transmission line with a capacity of 660 MW. The line is bi-directional, but in 2008, power flows were only from PJM to New York. Power is exported directly from New Jersey to Long Island. For 2008, the total real-time scheduled net exports on the Neptune line were 5,133 GWh while the day-ahead scheduled net exports were 5,169 GWh. Figure 4-11 shows the hourly average flow, by hour of the day, on the Neptune line for calendar year 2008. The average hourly flow during 2008 was -572 MWh. For the calendar year 2008, the average hourly PJM/NEPT Interface price was $84.74 per MWh, while in NYISO the Long Island zone's average price was $99.07 per MWh.

Figure 4-11 Neptune hourly average flow: Calendar Year 2008



Interface Pricing Agreements with Individual Companies

PJM consolidated the southeast and southwest interface pricing points to a single interface (SOUTHIMP and SOUTHEXP) on October 31, 2006.[25] The consolidation was based on an analysis which showed that scheduled flows were not consistent with actual power flows. The issue, which has arisen at other interface pricing points, is that the multiple pricing points may create the ability to engage in false arbitrage. False arbitrage occurs when participants schedule transactions in response to interface price differences but the actual power flows associated with the transaction serve to drive prices further apart rather than relieving the underlying congestion. Some market participants complained that their interests were harmed by PJM's consolidation of the southeast and southwest interface pricing points.

PJM subsequently entered into confidential bilateral locational interface pricing agreements with three companies affected by the revised interface pricing point that provided more advantageous pricing to these companies than the applicable interface pricing rules. The three companies involved and the effective date of their agreements are: Duke Energy Carolinas, January 5, 2007;[26] Progress Energy Carolinas, February 13, 2007;[27] and North Carolina Municipal Power Agency (NCMPA),

25 PJM posted a copy of its notice, dated August 31, 2006, on its Website at: <http://www.pjm.com/~/media/etools/oasis/pricing-information/interface-pricing-point-consolidation.ashx>
26 See "Duke Energy Carolinas Interface Pricing Arrangements" (January 5, 2007) (Accessed January 13, 2009) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/duke-pricing-agreement.ashx> (171 KB).
27 See "Progress Energy Carolinas, Inc. Interface Pricing Arrangements" (February 13, 2007) (Accessed January 13, 2009) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/pec-pricing-agreement.ashx> (210 KB).

March 19, 2007.[28] Each of these agreements established a locational price for power purchases and sales between PJM and the individual company that applies under specified conditions. For example, when the company desires to sell into PJM (a PJM import), the rules require that the company cannot have simultaneous scheduled imports from other areas. Similarly, when a company wants to purchase from PJM (a PJM export), the rules require that the company cannot simultaneously have scheduled exports to other areas.

There are a number of issues with these agreements including that they were not made public until specifically requested by the MMU, that the pricing was not available to other participants in similar circumstances, that the pricing did not reflect actual power flows, that the pricing did not reflect security constrained economic dispatch in the external areas and that the pricing did not reflect appropriate price signals. PJM recognized that the price signals in the agreements were inappropriate and notified the counterparties that PJM would be terminating the agreements effective January 31, 2009.[29]

Table 4-11 shows the LMP calculated per the bilateral agreements and, for comparison, the SOUTHIMP and SOUTHEXP LMP for calendar year 2008. The difference between the LMP under the agreements and PJM's SOUTHIMP LMP ranged from $4.18 with Duke to $6.98 with PEC while the difference between the LMP under the agreements and PJM's SOUTHEXP LMP ranged from $4.20 with Duke to $7.01 with PEC.

Table 4-11 Average hourly LMP comparison for Duke, PEC and NCMPA: Calendar year 2008.

	LMP	SOUTHIMP	SOUTHEXP	Difference LMP - SOUTHIMP	Difference LMP - SOUTHEXP
Duke	$59.65	$55.47	$55.45	$4.18	$4.20
PEC	$62.46	$55.47	$55.45	$6.98	$7.01
NCMPA	$59.72	$55.47	$55.45	$4.25	$4.28

In response to requests for broader applicability, PJM proposed a new pricing methodology. PJM filed tariff revisions with FERC that allowed for a three phase approach, with a sunset date of January 2010, and provided for the parallel development of an interregional congestion management agreement.[30]

The broader issue is how best to provide price signals to external areas, including both market and non market areas. The goal of interface pricing is to match actual, physical flows into and out of PJM with appropriate locational marginal price signals. An appropriate locational marginal price signal for an external generating unit is a price signal identical to that which would result from an LMP system, which reflects the actual incremental dispatch of units to meet incremental load, in the presence of transmission constraints. Prices which ignore the actual dispatch of generation in external areas and its impacts on locational prices, including PJM locational prices, will result in inefficient pricing, the potential for increased loop flows and the potential for gaming at the expense of PJM members. Comprehensive interregional congestion management agreements that

28 See "North Carolina Municipal Power Agency Number 1 Interface Pricing Arrangement" (March 19, 2007) (Accessed January 13, 2009) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/electricities-pricing-agreement.ashx> (279 KB).

29 See "Interface Pricing Discussion" (September 11, 2008) (Accessed February 25, 2009) <http://www.pjm.com/Media/committees-groups/committees/mic/20080911-item-05a-interface-pricing-presentation.pdf> (44 KB).

30 *PJM Interconnection LLC.*, Tariff Filing, Docket No. ER09-369-000 (December 2, 2008).

provide for joint redispatch to relieve congestion are an essential starting point for establishing the basis for accurate pricing. Such agreements would provide for redispatch and LMP modeling on both sides of existing seams in order to ensure that all participants receive the correct price signals, consistent with their impact on the underlying electrical network. The goal is to establish locational marginal price signals that accurately reflect all loads, generation and power flows based on security constrained economic dispatch, in all areas where entities want to sell to and buy from PJM markets. This does not mean that any external entity or area would have to use locational marginal pricing for its own internal purposes.

Interchange Transaction Issues

Interchange transactions may occur in the Real-Time Energy Market or in the Day-Ahead Energy Market. Issues arise in both the Real-Time and Day-Ahead Markets.

Interchange Transactions – Real-Time Energy Market

There are three steps required for market participants to enter external interchange transactions in PJM's Real-Time Energy Market. The steps are: acquisition of valid transmission via the Open Access Same Time Information System (OASIS); acquisition of available ramp via PJM's Enhanced Energy Scheduler system (EES); and the creation of a valid NERC Tag. In addition, the interchange request must pass the neighboring balancing authority checkout process in order for the request to be implemented. After a successful implementation of an external energy schedule, the energy will flow between balancing authorities. Such a transaction will continue to flow at its designated energy profile as long as the system can support it, it is deemed economic based on options set at the time of scheduling, or until the market participant chooses to curtail the transaction.

While the OASIS has a path component, this path only reflects the path of energy into or out of PJM to one neighboring balancing authority. The NERC Tag requires the complete path to be specified from the Generation Control Area (GCA) to the Load Control Area (LCA). This complete path is utilized by PJM to determine the interface pricing point which PJM will associate with the transaction.

Interchange Transactions – Day-Ahead Energy Market

Entering external energy transactions in the Day-Ahead Market requires fewer steps than the Real-Time Market. Market participants need to acquire a valid OASIS reservation to prove that their day-ahead schedule could be supported in the Real-Time Market. Day-Ahead Market schedules need to be cleared through the Day-Ahead Market process in order to become an approved schedule. The Day-Ahead Market transactions are financially binding but will not physically flow. In the Day-Ahead Market, a market participant is not required to acquire a ramp reservation or a NERC Tag or to go through a neighboring balancing authority checkout process.

There are three types of day-ahead external energy transactions: Fixed; Up-to congestion; and Dispatchable.

A fixed Day-Ahead Market transaction request means that the market participant agrees to be a price taker for the MW amount of the offer. There is no price associated with the request and the market participant agrees to take the day-ahead LMP at the associated source or sink. If the market participant has met the required deadline and has acquired a valid willing-to-pay congestion OASIS reservation, a fixed day-ahead transaction request will be accepted in the Day-Ahead Market. These approved transactions are a financial obligation. If the market participant does not provide a corresponding transaction in the Real-Time Market, they are subject to the balancing market settlement.

To submit an up-to congestion offer, the market participant is required to submit an energy profile (start time, stop time and MW value) and specify the amount of congestion they are willing to pay. If, in the Day-Ahead Market, congestion on the desired path is less than that specified, the up-to congestion request is approved. Approved up-to congestion offers are financial obligations.

Dispatchable transactions in the Day-Ahead Market are similar to those in the Real-Time Market in that they are evaluated against a floor or ceiling price at the designated import or export pricing point. For import dispatchable transactions, if the LMP at the interface clears higher than the specified bid, the transaction is approved. For export dispatchable transactions, if the LMP at the interface clears lower than the specified bid, the transaction is approved. As with fixed and up-to congestion transactions, cleared dispatchable transactions in the Day-Ahead Market represent a financial obligation. If the market participant does not meet the commitment in the Real-Time Market, they are subject to the balancing market settlement.

Transactions Issues in the Real-Time Energy Market

Spot Import

Spot market imports, non-firm point-to-point and network services that are willing to pay congestion, collectively Willing to Pay Congestion (WPC), were part of the PJM LMP energy market design implemented on April 1, 1998. WPC provided market participants the ability to offer energy into or bid to buy from the PJM spot market at the border/interface as price takers without restrictions based on estimated available transmission capability. Price and PJM system conditions, rather than ATC, effectively limited imports.

Prior to April 1, 2007, PJM did not limit non-firm service imports that were willing to pay congestion, including spot imports, secondary network service imports and bilateral imports using non-firm point-to-point service. However, PJM interpreted its Joint Operating Agreement (JOA) with Midwest ISO (MISO) to require a limitation on cross-border transmission service and energy schedules in order to limit the impact of such transactions on selected external flowgates.[31] The rule caused the availability of spot import service to be limited by ATC on the transmission path. As a result of the rule, requests for service sometimes exceeded the amount of service available to customers. Unlike non-firm point-to-point WPC service, spot import (a network service) is provided at no charge to the market participant offering into the PJM spot market.

31 See "WPC White Paper" (April 20, 2007) (Accessed December 29, 2008) <http://www.pjm.com/~/media/etools/oasis/wpc-white-paper.ashx>(97 KB).

In response to market participant complaints regarding the inability to acquire spot import service after this rule change on April 1, 2007, changes were made to the spot import service effective May 1, 2008.[32] These changes limited spot imports to only hourly reservations and caused spot import service to expire if not associated with a valid NERC Tag within 2 hours when reserved the day prior to the scheduled flow or within 30 minutes when reserved on the day of the scheduled flow.

Some market participants responded to the new rules by reserving spot import service but tagging only 1 MW against the reservation. This prevented the transmission reservation from expiring and allowed them to hold it for future use. This approach does not prevent other participants from obtaining transmission capability, as the ATC for the next hour is calculated based on the level of transmission with a NERC Tag and not reservations. Any transmission not scheduled on the NERC Tag would become available in the next hour.

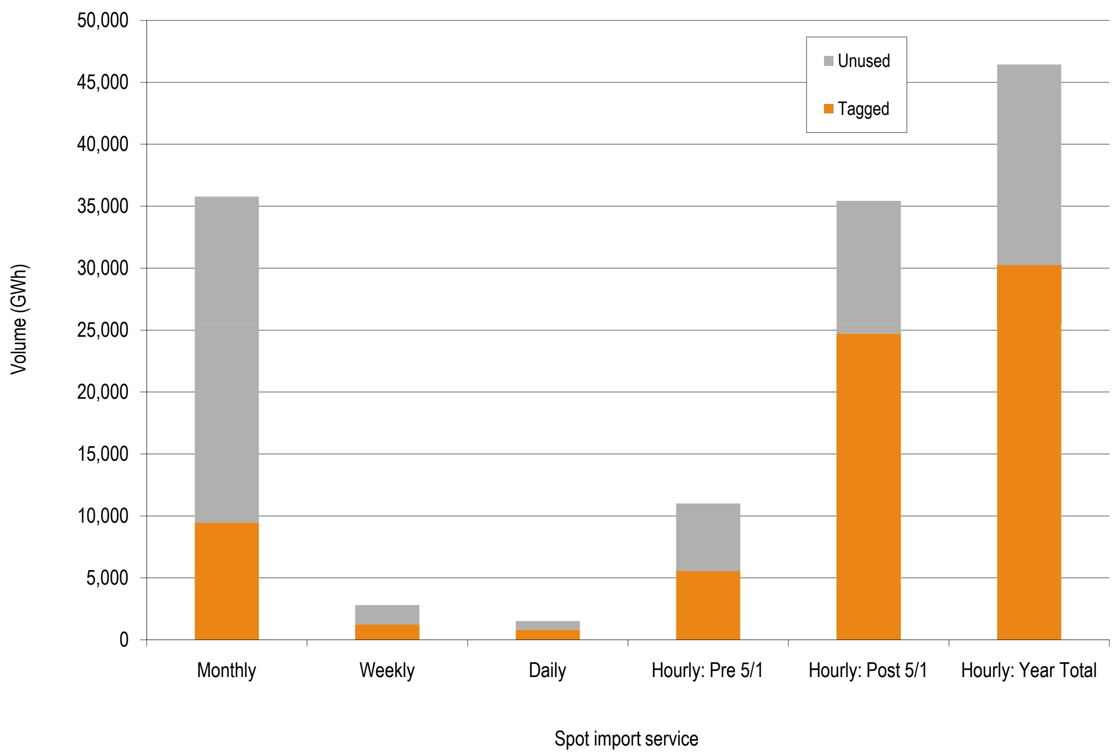
The new rules governing spot import service could have an unanticipated effect. For example, if there were 1,000 MW of ATC posted for a particular hour, a market participant could reserve the 1,000 MW of transmission service and schedule 1 MW against it. In the next hour, 999 MW of ATC would be posted for the same hour. A second market participant could reserve the 999 MW of service and schedule 1 MW against it. In this example, there are 1,999 MW of transmission reserved on a path that has a reliable limit of 1,000 MW. If both market participants chose to utilize their full allocation of spot import service, the potential exists for creating a transmission system limit to be exceeded.

The MMU recommends that PJM reconsider whether the new approach to limiting spot import service is required or whether a return to the prior policy with an explicit system of managing any related congestion is preferable.

Figure 4-12 shows the utilization of spot import service for calendar year 2008. As of May 1, 2008, only hourly spot import service is available. The spot reservations for the monthly, weekly and daily options represent those reservations that existed prior to the modifications.

32 See "Regional Transmission and Energy Scheduling Practices" (May 1, 2008) (Accessed December 29, 2008) <http://www.pjm.com/~/media/etools/oasis/20090131-regional-practices-redline.ashx> (450 KB).

Figure 4-12 Spot import service utilization: Calendar year 2008



Willing to Pay Congestion and Not Willing to Pay Congestion

The source and sink of an OASIS reservation designate the buses on the PJM system for which settlement LMPs are calculated. For import external energy transactions, the source defaults to the external interface as determined by the selected Point of Receipt (POR) and Point of Delivery (POD). For export external energy transactions, the sink defaults to the external interface as determined by the selected POR and POD. For wheel through transactions, both the source and sink default to the external interfaces as determined by the selected POR and POD (the source defaults to the POR interface and the sink defaults to the POD interface). The market participant can then select the source or sink that is not pre-determined by the selected path. This selection determines the explicit congestion charge that the market participant is exposed to, as congestion is calculated as the difference in LMP from the sink to the source.

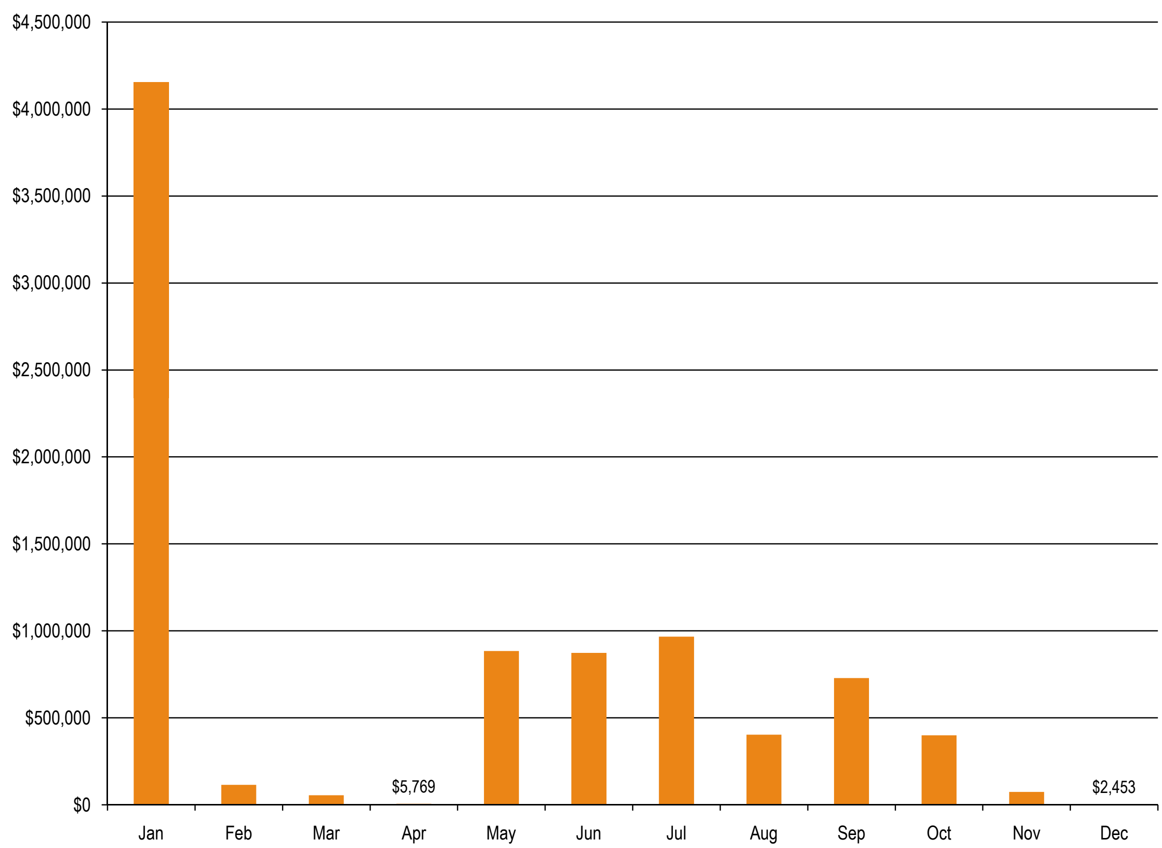
When reserving non-firm transmission, the market participant has the option to choose whether or not they are willing to pay congestion. When the market participant elects to pay congestion, PJM operators redispatch the system, if necessary, to allow the energy transaction to continue to flow and congestion results.

If a market participant is not willing to pay congestion, the market participant expects the PJM operators to curtail their transaction as soon as there is a difference in LMPs between their selected source and sink.

Uncollected congestion charges occur when PJM operators do not curtail a not willing to pay congestion transaction when there is congestion. In January 2008, approximately four million dollars in uncollected congestion charges were realized by PJM related to not willing to pay congestion transmission reservations. Many of the transactions that contributed to the uncollected congestion charges were only 15 minutes in duration. The method that PJM uses to curtail not willing to pay congestion requires the transaction to be loaded. While loaded, if congestion occurs for a not willing to pay congestion transaction, a message is sent to the PJM operators requesting the transaction be curtailed at the next 15 minute interval. When transactions are scheduled for only 15 minutes, market participants are able to complete a transaction in the presence of congestion without paying congestion charges.

The market participants whose activities resulted in uncollected congestion charges were contacted by the MMU and the uncollected congestion charges were significantly reduced over the next few months. The issue reappeared in May, although to a lesser extent. (See Figure 4-13). The MMU recommends modifying the evaluation criteria via a modification to PJM's market software, to ensure that not willing to pay congestions transactions are not permitted to flow in the presence of congestion.

Figure 4-13 Monthly uncollected congestion charges: Calendar year 2008



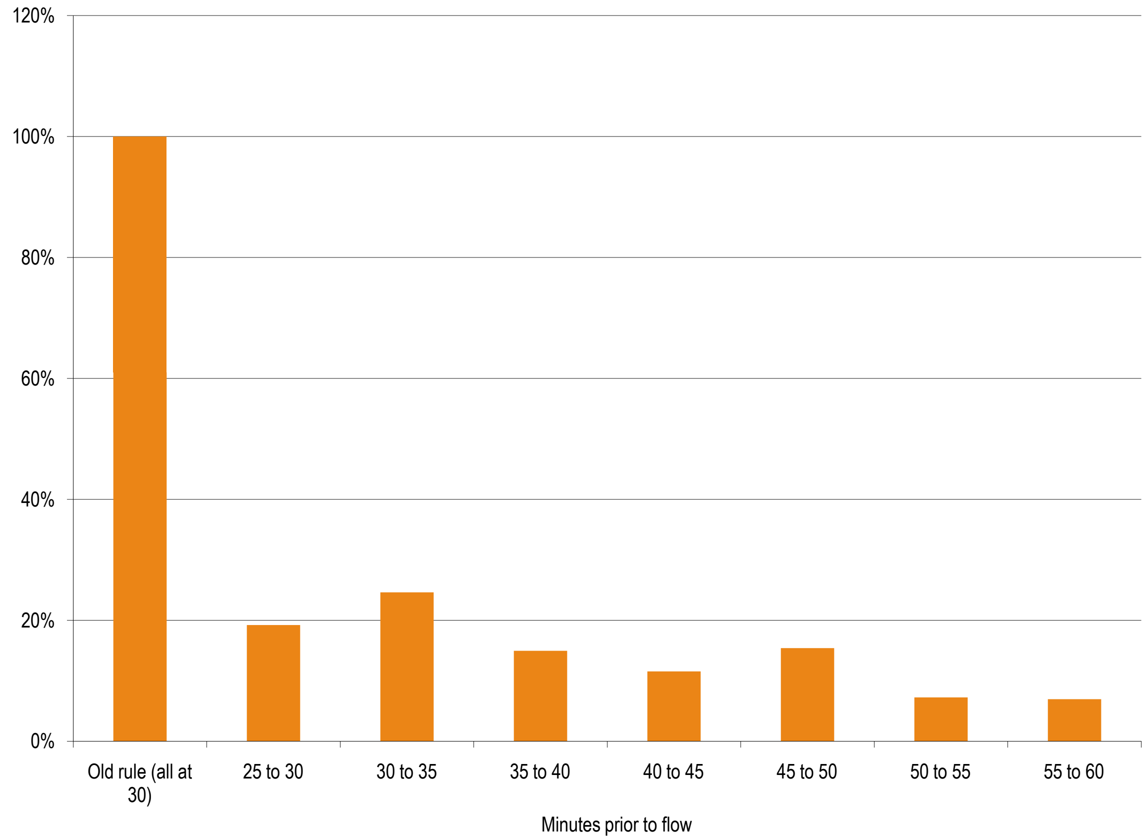
Ramp Availability

PJM limits the amount of change in net interchange within 15-minute intervals in order to ensure compliance with NERC performance standards. Changes in net interchange affect PJM operations and markets as they require increases or decreases in generation to meet load. The change in net interchange is referred to as ramp. Any market participant wishing to initiate (or to change) a transaction must obtain a ramp reservation. PJM issues reservations, on a first-come, first-served basis, up to the ramp limit.

While ramp limits may be modified by PJM depending on system conditions, the default limit is ± 1,000 MW within a 15-minute interval. For example, if at 0800 Eastern Prevailing Time (EPT) the sum of all external transactions were -3,000 MW (negative sign indicates net exporting), the limit for 0815 would be -2,000 MW to -4,000 MW. In other words, the starting or ending of transactions would be limited so that the overall change from the previous 15-minute period would not exceed 1,000 MW in either direction.

Figure 4-14 shows the ongoing results of the ramp rule change that became effective on August 7, 2006. Under the new rule, unused ramp reservations expire at the conclusion of a defined time interval that starts when a reservation is approved. The goal was to prevent large swings in ramp 30 minutes prior to flow, and to spread automatic ramp reservation expirations over a longer period to permit other participants to use them. The actual distribution pattern of expirations since the rule change is compared to when reservations would have expired under the old rule in Figure 4-14. Under the old rule, all unused reservations had expired at the same time, 30 minutes prior to flow or just 10 minutes prior to the deadline for scheduling a transaction (20 minutes prior to flow).

Figure 4-14 Distribution of expired ramp reservations in the hour prior to flow (Old rules (Theoretical) and new rules (Actual)) October 2006 to December 2008



The artificial creation of ramp room is an ongoing issue. For example, a market participant who wishes to initiate an import transaction when there is no available import ramp, requests a ramp reservation in the exporting direction. When accepted, this reservation creates apparent import ramp, which permits the participant to obtain an import reservation. The import transaction flows and the export reservation expires after its time limit. In 2007, PJM modified its business rules to permit PJM to cut such a participant's transaction(s) prior to using the normal, last-in-first-out method of ordering cuts, if PJM determines that a participant has scheduled an offsetting reservation that is unused.[33] Although the rule has been added, the mechanism for automatically performing this task has not yet been developed. System operators may apply this rule manually.

Large swings in PJM's ramp availability have continued to be regularly observed at the NYISO interface. The NYISO rules for its hourly market require transaction bids to be placed at least 75 minutes prior to flow. For each potential import or export transaction that is bid into the NYISO market, a PJM ramp reservation is required. During the time between the bid submission to NYISO and the time the NYISO market results are posted, all ramp reservations associated with all the bids are in PJM's system, often leaving no ramp available, awaiting the outcome of the NYISO

33 PJM. "Manual 41: Managing Interchange," Revision 03 (November 24, 2008), p. 9.

market clearing. When the NYISO market results are posted, the ramp reservations for any unsuccessful bids are returned to the PJM system. The result is a large swing in ramp observed at approximately 20 minutes after the hour. The difference between transaction rules in NYISO and PJM create incentives to obtain ramp that will not be needed. There is also the potential for gaming by submitting out-of-market bids and offers for import or export transactions to the NYISO, thus limiting ramp availability to competitors. Additionally, market participants can extend their NYISO market bids to cover multiple hours to acquire ramp by submitting out-of-merit bids and offers. For example, if ramp is not available at the end time of the desired hour, the market participant can submit a NYISO schedule to cover two hours, thus having no effect at the time when ramp is not available. When the NYISO evaluates the second hour, it will not pass their market (as it is out-of-merit) and they will deny the transaction. PJM will have no choice but to remove the transaction from the second hour, thus causing a ramp violation at the end of the first hour where ramp was initially not available.

The purpose of imposing a ramp limit is to help ensure the reliable operation of the PJM system. The 1,000 MW ramp limit was based on the availability of ramping capability by generators on the PJM system. The available generation on the PJM system can only move 1,000 MW over any given 15 minute period. PJM must limit the amount of imports or exports at each 15 minute interval to account for the physical characteristics of the generation to meet the imports and exports. In 2008, there was an increase in 15 minute external energy transactions that caused swings in imports and exports submitted in response to intra-hour LMP changes. As a result, a new business rule was proposed and approved to require all transactions to be at least 45 minutes in duration.[34] The EES system was to be modified to require that transactions be 45 minutes in duration. As of the end of 2008, the modification to the EES application had not been completed. Market participants have been scheduling 1 MW for the first 30 minutes, and increasing to a larger MW value for the last 15 minutes, thus continuing to create significant swings in imports and exports. The MMU recommends that the EES application be modified to account for the constant MW rule over the entire 45 minutes as soon as possible.

Curtailment of Transactions

Once a transaction has been implemented, energy flows between balancing authorities. Transactions can be curtailed under several conditions, including economic and reliability considerations.

There are three types of economic curtailments: curtailments of dispatchable schedules; OASIS designation curtailments; and market participant self-curtailments. System reliability curtailments are termed TLRs or transmission loading relief.

A dispatchable external energy transaction (also known as “real-time with price”) is one in which the market participant designates a floor or ceiling price on their external transaction from which they would like the energy to flow. For example, an import dispatchable schedule specifies that the market participant only wishes to load the transaction if the LMP at the interface from which the transaction is entering the PJM footprint reaches a specified limit (the minimum LMP they are willing to sell at). An export dispatchable schedule specifies the maximum LMP at the interface from which the market participant wishes to purchase the power from PJM.

34 PJM. “Manual 41: Managing Interchange,” Revision 03 (November 24, 2008), p. 5.

PJM system operators evaluate dispatchable transactions 30 minutes prior to the start of every hour of the energy profile. If the system operator expects the floor (or ceiling) price to be realized over the next hour, they contact the market participant informing them that they are loading the transaction. Once loaded, the dispatchable transaction will run for the next hour. If at any time the system operator does not feel that the transaction will be economic, they will elect to curtail the dispatchable transaction. Dispatchable schedules can be viewed as a generation offer, with a minimum run time of one hour. If prices are such that the transaction should not have been loaded, it will be made whole in the settlement process.

Not willing to pay congestion transactions can be curtailed if there is realized congestion between the designated source and sink.

Spot import service is dispatchable at a price of zero, by definition. If the interface price reaches zero, PJM system operators will curtail all transactions using spot import service flowing over that interface.

A market participant may curtail their transactions. All self curtailments must be requested on 15 minute intervals. In order for PJM to approve a self curtailment request, there must be available ramp for the modification.

TLRs

TLRs are called to control flows on electrical facilities when economic redispatch cannot solve overloads on those facilities. TLRs are generally called to control flows related to external balancing authorities, as redispatch within an LMP market can generally resolve overloads on internal transmission facilities.

PJM called more TLRs in 2008 than in 2007. The primary reason for the increase in TLR activity in 2008 was the result of transmission line outages caused by storms and tornados. The transmission line outages reduced the ability to control power flows via redispatch, creating the need to utilize TLRs. PJM TLRs increased by 87.5 percent, from 80 during 2007 to 150 in 2008. (See Figure 4-15.) In addition, the number of different flowgates for which PJM declared TLRs increased from 27 during 2007 to 37 in 2008. (See Figure 4-16.) The total MWh of transaction curtailments increased by 76 percent, from 288,616 MWh in 2007 to 506,617 MWh in 2008. (See Figure 4-17.) Of the 150 TLRs called by PJM in 2008, three facilities comprised 47 percent of the total. The three facilities were:

- **East Frankfort – Crete 345 kV Line for Loss of Dumont – Wilton Center 765 kV Line.** These lines are located in northern Illinois, close to the border of Indiana. TLRs on this flowgate were generally utilized to control flows across the Illinois-Indiana border through the Northern Indiana Public Service system. While PJM and MISO work together to control these flows using the mechanisms prescribed in the JOA, the actions were not always sufficient. TLRs on this flowgate were used to control the constraints (35 TLRs in 2008; 0 TLRs in 2007);

- **Person – Halifax 230 kV Line for loss of Wake – Carson 500 kV Line.** These lines are located in southern Virginia and North Carolina. Power flows to/from PJM's southern neighbors, loop flows and heavy power flows in either the north-to-south or south-to-north direction at PJM's southeastern border are the main reasons for TLRs on this line (23 TLRs in 2008; 8 TLRs in 2007); and

- **Kammer #200 765 to 500 kV Transformer for Loss of Belmont – Harrison 500 kV Line.** This is a 765 to 500 kV transformer located near the border of Ohio and West Virginia. The Belmont – Harrison 500 kV line runs in northern West Virginia near the southwest corner of Pennsylvania. Economic dispatch of lower cost units in the west can cause high flows at Kammer. This constraint is not easily controllable with redispatch because of lack of generation with the necessary impact (15 TLRs in 2008; 9 TLRs in 2007).

Midwest ISO called significantly fewer TLRs in 2008 than in 2007. Midwest ISO TLRs decreased by about 27 percent, from 819 during 2007 to 597 in 2008. (See Figure 4-15.)

Figure 4-15 PJM and Midwest ISO TLR procedures: Calendar years 2007 and 2008

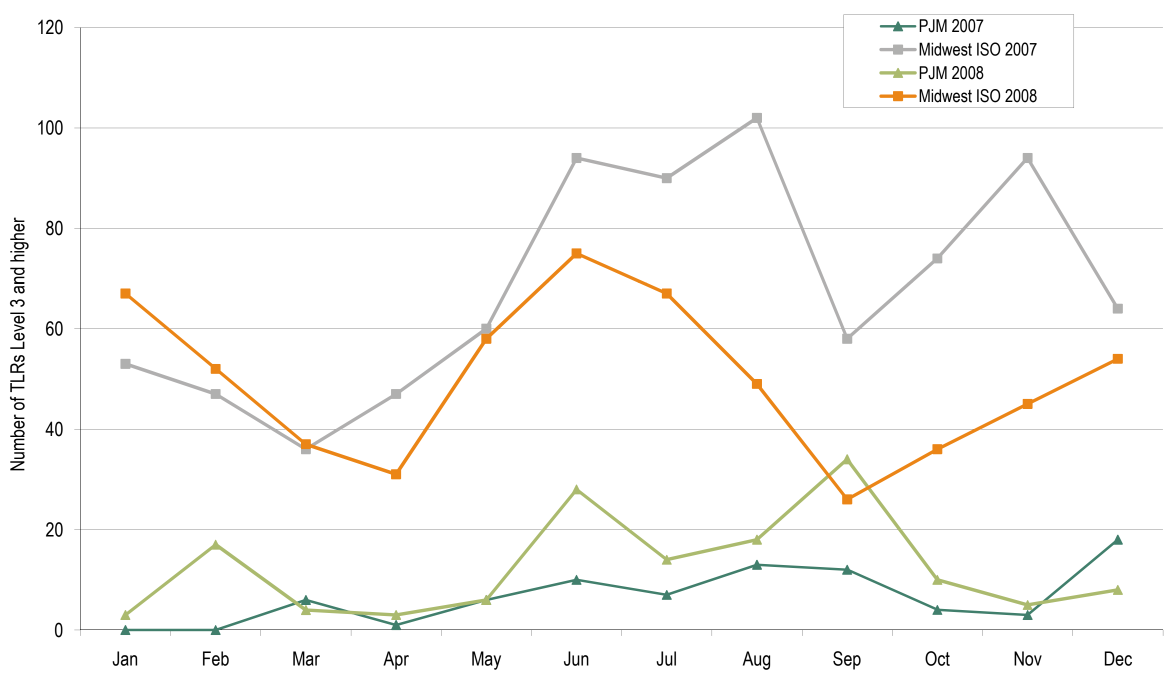


Figure 4-16 Number of different PJM flowgates that experienced TLRs: Calendar years 2007 to 2008

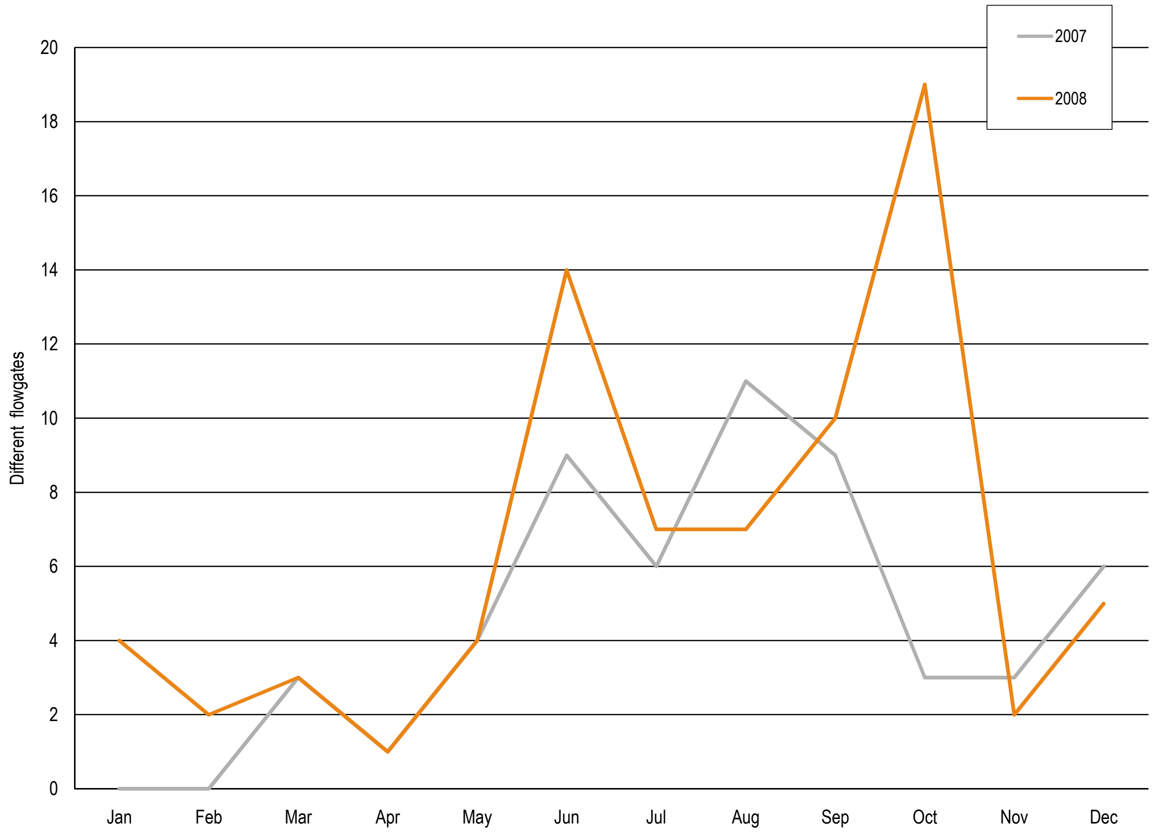
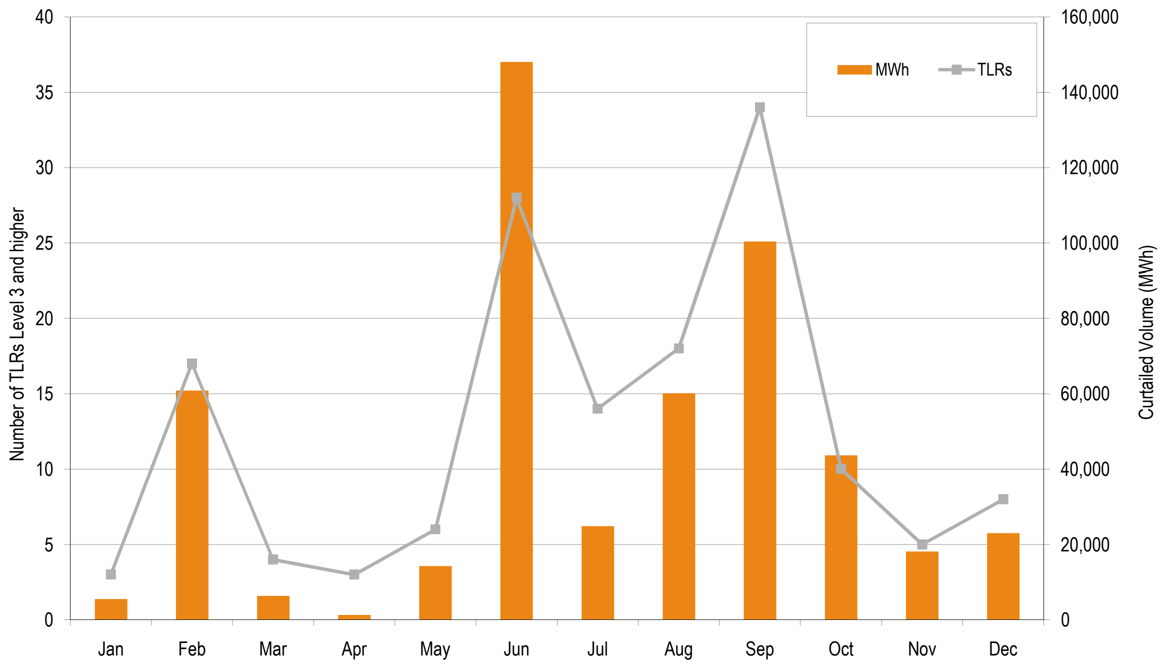


Figure 4-17 Number of PJM TLRs and curtailed volume: Calendar year 2008



Up-To Congestion

In 2008, market participants requested that PJM increase the maximum value for up-to congestion offers, and to also allow negative offers for these transactions. PJM expressed concerns regarding the mismatch between up-to congestion transactions in the Day-Ahead Market and real-time transactions.[35] In the Day-Ahead Energy Market, an up-to congestion import transaction is submitted and modeled as an injection at the interface and a withdrawal at a specific PJM node. In real time, the power does not flow to the PJM node specified in the day-ahead transaction. This mismatch results in inaccurate pricing and can provide a gaming opportunity. Increasing the offer cap, and allowing negative offers, could potentially increase the cleared volume of up-to congestion transactions, and aggravate the issue.

On February 21, 2008, the MRC approved PJM's proposed resolution to the request for implementation on March 1, 2008.[36] The proposal allowed for an increased offer cap from $25 to ± $50, and explicitly allowed for negative offers. PJM also eliminated certain available sources and sinks in an effort to address the mismatches between the Day-Ahead and Real-Time Markets. As part of the agreement, PJM will maintain an up-to date list of sources and sinks that will be unavailable for up-to congestion bids. This list will be posted on the PJM OASIS.[37] In the months following the modifications to the up-to congestion bids, the total MWh of up-to congestion bidding has significantly increased from previous years. (See Figure 4-18.)

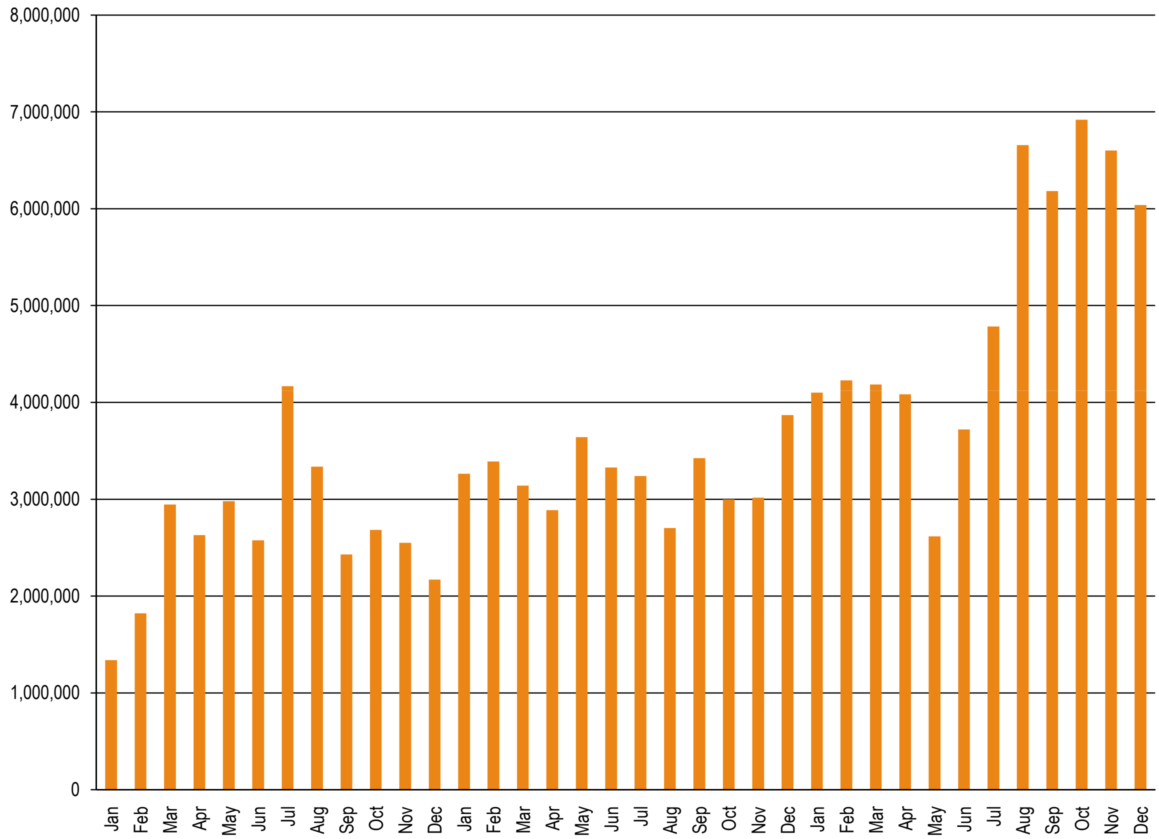
35 See PJM. "Up-to Congestion Transactions. Proposed Interim Changes Pending Development of a Spread Product" (February 21, 2008) (Accessed February 18, 2009) <http://www.pjm.com/~/media/committees-groups/committees/mrc/20080221-item-03-up-to-congestion-transactions.ashx> (38KB).

36 See PJM. "20080221-minutes.pdf" (February 21, 2008) (Accessed January 15, 2009) <http://www.pjm.com/Media/committees-groups/committees/mrc/20080221-minutes.pdf > (61KB).

37 See PJM. "20080303-oasis-sources-and-sinks.ashx" (March 3, 2008) (Accessed January 15, 2009) <http://www.pjm.com/markets-and-operations/etools/oasis/~/media/etools/oasis/20080303-oasis-sources-and-sinks.ashx > (61KB).

The MMU recommends that PJM consider eliminating all internal PJM buses for use in up-to congestion bidding. In effect, the use of specific buses is equivalent to creating a scheduled transaction which will not equal the actual corresponding power flow.

Figure 4-18 Monthly up-to congestion bids in MWh: Calendar years 2006 to 2008



Loop Flows

Actual flows are the metered flows at an interface for a defined period. Scheduled flows are the flows scheduled at an interface for a defined period. Inadvertent interchange is the difference between the total actual flows for the PJM system (net actual interchange) and the total scheduled flows for the PJM system (net scheduled interchange) for a defined period. Loop flows are measured as the difference between actual and scheduled flows at one or more specific interfaces. Loop flows can exist at the same time that inadvertent interchange is zero. For example, actual imports could exceed scheduled imports at one interface and actual exports could exceed scheduled exports at another interface. The result is loop flow, despite the fact that system actual and scheduled flow could net to a zero difference.

Loop flow can arise from transactions scheduled into, out of or around the PJM system on contract paths that do not correspond to the actual physical paths on which energy flows. Outside of LMP-based energy markets, energy is scheduled and paid for based on contract path, without regard to the path of the actual energy flows. Loop flows can also exist as a result of transactions within a market-based area in the absence of an explicit agreement to price congestion. Loop flows exist because electricity flows on the path of least resistance regardless of the path specified by contractual agreement or regulatory prescription. PJM manages loop flow using a combination of interface price signals, redispatch and TLR procedures.

Loop flows are a significant concern. Loop flows have negative impacts on the efficiency of markets with explicit locational pricing, including impacts on locational prices, on FTR revenue adequacy and on system operations, and can be evidence of attempts to game such markets. Loop flows also have poorly understood impacts on non market areas. In general, the detailed sources of the identified differences between scheduled and actual flows remain unclear.

The fact that total PJM net actual interface flows were close to net scheduled interface flows, on average for 2008 as a whole, is not a useful measure of loop flow. There were significant differences between scheduled and actual flows for specific individual interfaces. (See Table 4-12.) From an operating perspective, PJM tries to balance overall actual and scheduled interchange, but does not have a mechanism to control the balance between actual and scheduled interchange at individual interfaces because there are free flowing ties with contiguous balancing authorities.

During 2008, for PJM as a whole, net scheduled and actual interchange differed by 1.7 percent.[38] (See Table 4-12.) Actual system net exports were 9,859 GWh, 174 GWh less than the scheduled total net exports of 10,032 GWh. Flow balance varied at each individual interface. The PJM/MECS Interface was the most imbalanced, with net actual exports of 11,001 GWh exceeding scheduled imports of 3,013 GWh by 14,014 GWh or 465 percent, for an average of 1,595 MW during each hour of the year. The case also existed at interfaces where there was a net scheduled export, but the actual flows were into PJM. This occurred at the PJM/AMIL, PJM/CPLE, PJM/FE, PJM/IPL, PJM/TVA and the PJM/WEC Interfaces. The largest difference occurred at the PJM/FE Interface, where scheduled exports were 2,450 GWh and actual flows were 6,761 GWh in the import direction, creating an imbalance of 9,211 GWh or 376 percent, for an average of 1,049 MW during each hour of the year.

38 Net scheduled volumes include dynamic schedules. These are scheduled flows from generating units that are physically located in one control area but deliver power to another control area. The power from these units flows over the lines on which the actual flow at PJM's borders is measured. Since the dynamic schedules are included in the actual flows, they must be included in the scheduled flows in order to accurately compare actual to scheduled flows. Dynamic flows are included in the "Net Scheduled" column of Table 4-12. As a result, the total "Net Scheduled" in Table 4-12 does not match the total net interchange in Table 4-1. The difference of 2,092 GWh is the net dynamic schedule.

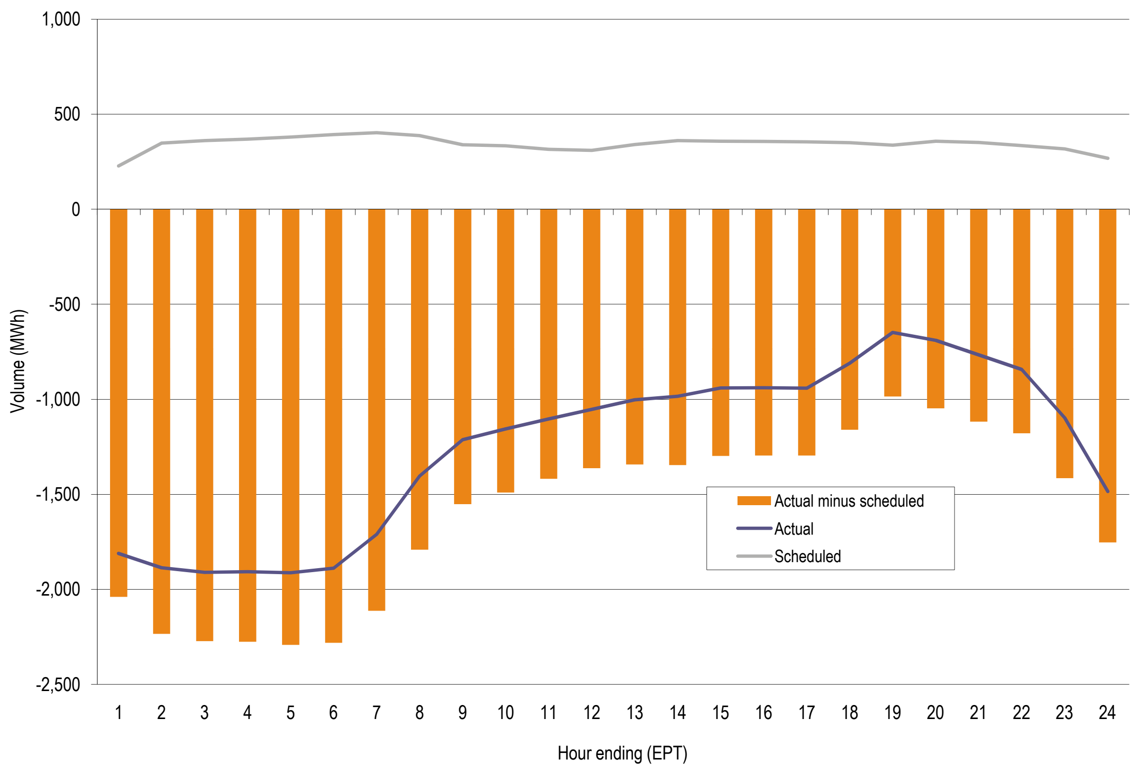
Table 4-12 Net scheduled and actual PJM interface flows (GWh): Calendar year 2008

	Actual	Net Scheduled	Difference	Difference (percent of net scheduled)
ALTE	(6,441)	(1,486)	(4,955)	333%
ALTW	(2,992)	(1,339)	(1,653)	123%
AMIL	5,060	(249)	5,309	(2132%)
CIN	2,301	3,950	(1,649)	(42%)
CPLE	6,804	(949)	7,753	(817%)
CPLW	(2,064)	(809)	(1,254)	155%
CWLP	(744)	(13)	(731)	5611%
DUK	(4,130)	(8)	(4,122)	50283%
EKPC	(586)	(1,447)	861	(59%)
FE	6,761	(2,450)	9,211	(376%)
IPL	2,736	(788)	3,524	(447%)
LGEE	1,325	1,680	(355)	(21%)
MEC	(3,699)	(1,742)	(1,957)	112%
MECS	(11,001)	3,013	(14,014)	(465%)
NEPT	(5,027)	(5,027)	-	0%
NIPS	(2,415)	(734)	(1,681)	229%
NYIS	(5,663)	(7,123)	1,460	(20%)
OVEC	7,591	9,553	(1,962)	(21%)
TVA	941	(3,124)	4,065	(130%)
WEC	1,385	(939)	2,324	(248%)
Total	(9,859)	(10,032)	174	(1.7%)

Loop Flows at the PJM/MECS and PJM/TVA Interfaces

As in 2007, the PJM/MECS Interface continued to exhibit large imbalances between scheduled and actual power flows, particularly during the overnight hours (hour ending 2400 through hour ending 0700). (See Figure 4-19.) Generally, the PJM/MECS Interface is an exporting interface, meaning that power flows from PJM to MECS. The actual exports exceeded the scheduled exports at that interface by an average of 2,164 MW per hour for those overnight hours. The daytime hours (hour ending 0800 through hour ending 2300) difference between actual and scheduled exports averaged 1,365 MW.

Figure 4-19 PJM/MECS Interface average actual minus scheduled volume: Calendar year 2008



While the PJM/TVA Interface also exhibited large mismatches between scheduled and actual power flows, the magnitude of the mismatches declined after consolidation. The PJM/MECS differences and the PJM/TVA differences were in opposite directions. The net difference between scheduled flows and actual flows at the PJM/TVA Interface was imports while the net difference at the PJM/MECS Interface was exports. (See Figure 4-19 and Figure 4-21.) The consolidation of the former southeast and southwest pricing points in October 2006 has had an ongoing impact at the PJM/TVA Interface.[39] Figure 4-20 shows the average hourly actual flows, scheduled flows and the difference between them for the preconsolidation time period January 1, 2006, through September 30, 2006. Actual exports were less than scheduled exports by 1,328 MWh every hour, on average during nine-month preconsolidation period. During calendar year 2008, this difference decreased by 64 percent to 480 MW (on average) each hour. (See Figure 4-21.)

39 For a more detailed discussion of this issue, see the *2006 State of the Market Report*, Volume II, Section 4, "Interchange Transactions," at "Loop Flows at PJM's Southern Interfaces."

Figure 4-20 PJM/TVA average flows: January 1, to September 30, 2006, pre-consolidation

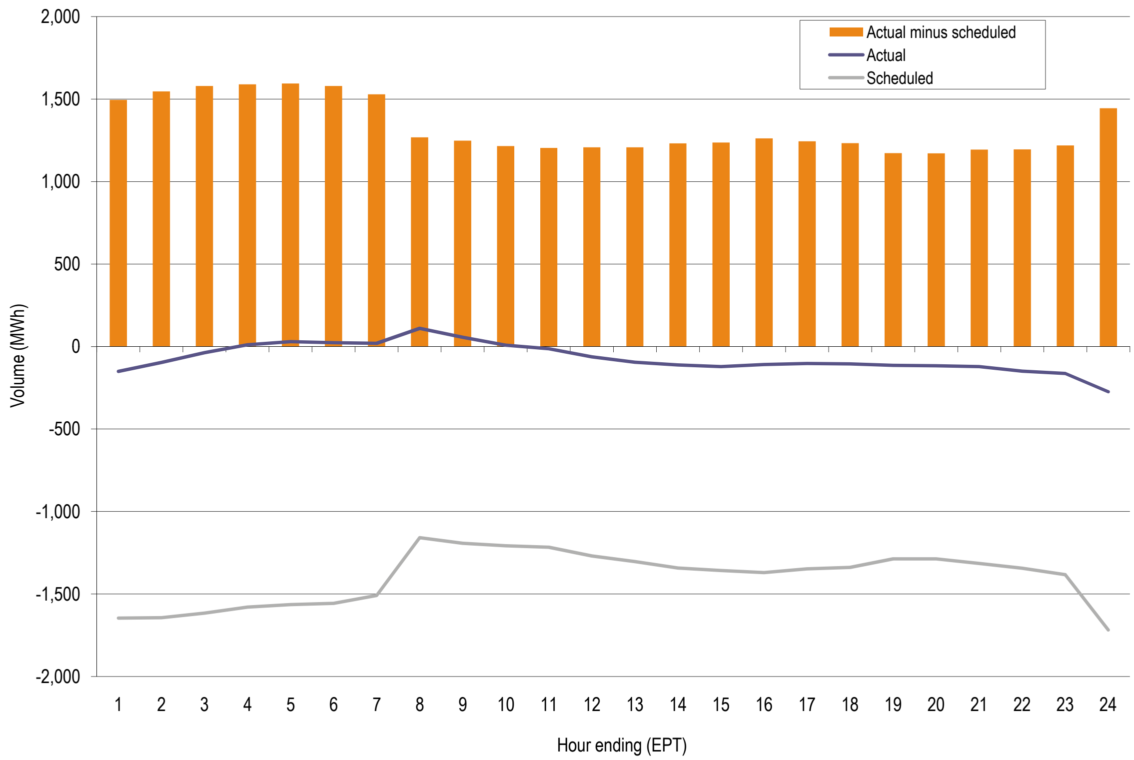
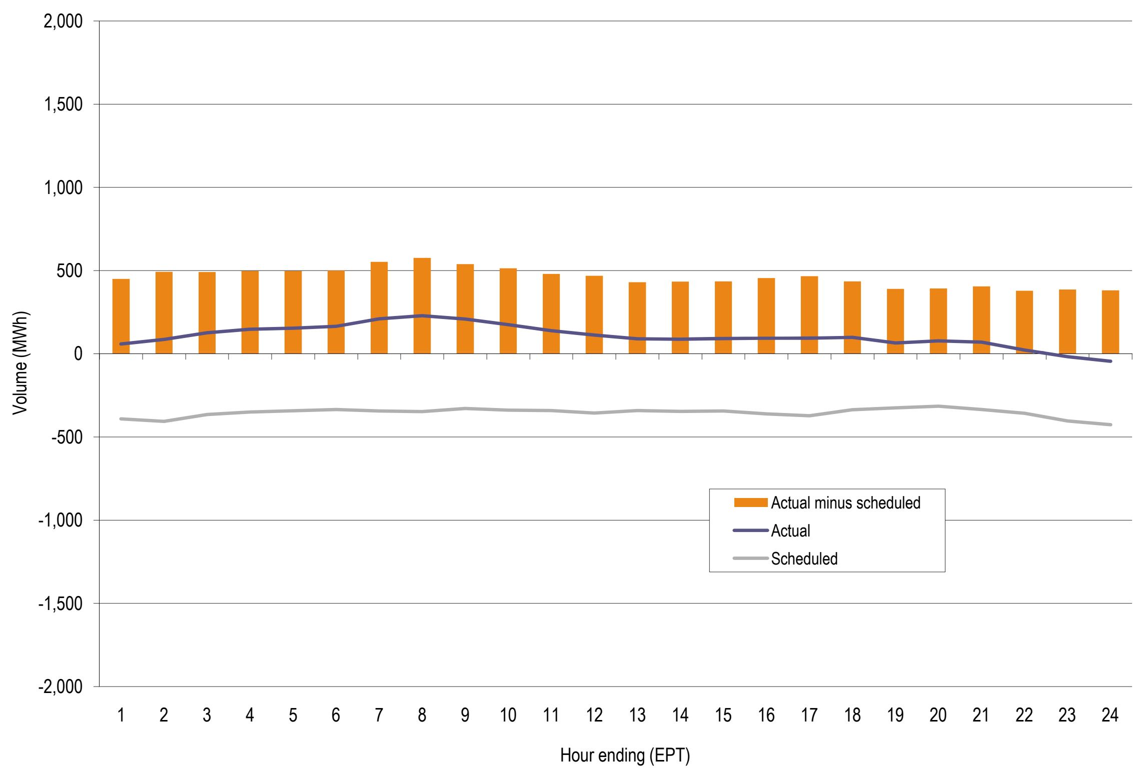


Figure 4-21 PJM/TVA average flows: Calendar year 2008



Loop Flows at PJM's Southern Interfaces

Figure 4-22 and Figure 4-23 illustrate the reduction in the previously persistent difference between scheduled and actual power flows at PJM's southern interfaces (PJM/TVA and PJM/EKPC to the west and PJM/CPLE, PJM/CPLW and PJM/DUK to the east) that grew to its largest volumes through the summer of 2006. One reason for this improvement was the consolidation of the former southeast and southwest pricing points into the SOUTHEXP and SOUTHIMP pricing points. In order to reflect the actual flow of transactions associated with the southeast and southwest interface pricing points, on October 1, 2006, PJM began to price all transactions that source in PJM and sink in one of the relevant, defined balancing authorities, at the SOUTHEXP interface pricing point. Similarly, PJM began to price all transactions that sink in PJM and source in one of the defined balancing authorities, at the SOUTHIMP interface pricing point. This practice enabled PJM to price imports and exports differently based on their impacts on the PJM transmission system. While the SOUTHIMP and SOUTHEXP pricing points have replaced the Southeast and Southwest pricing points, Figure 4-22 and Figure 4-23 are included for comparison.

Figure 4-22 Southwest actual and scheduled flows: Calendar years 2006 to 2008

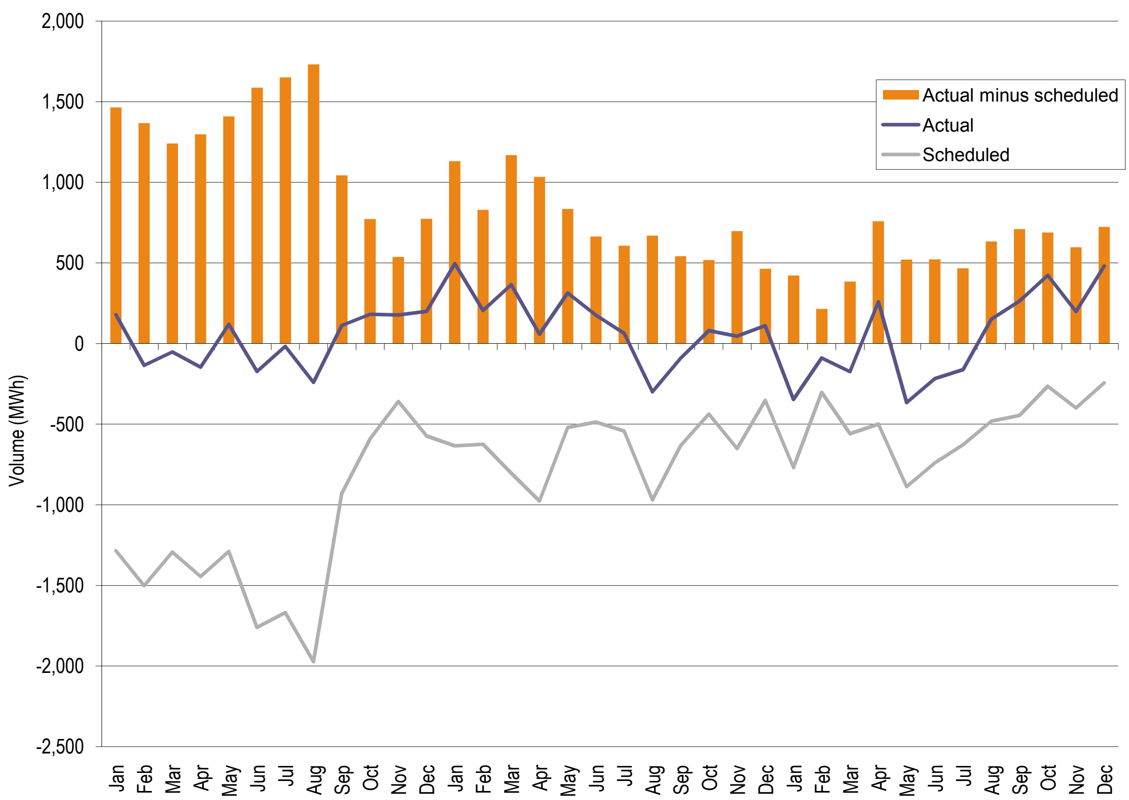
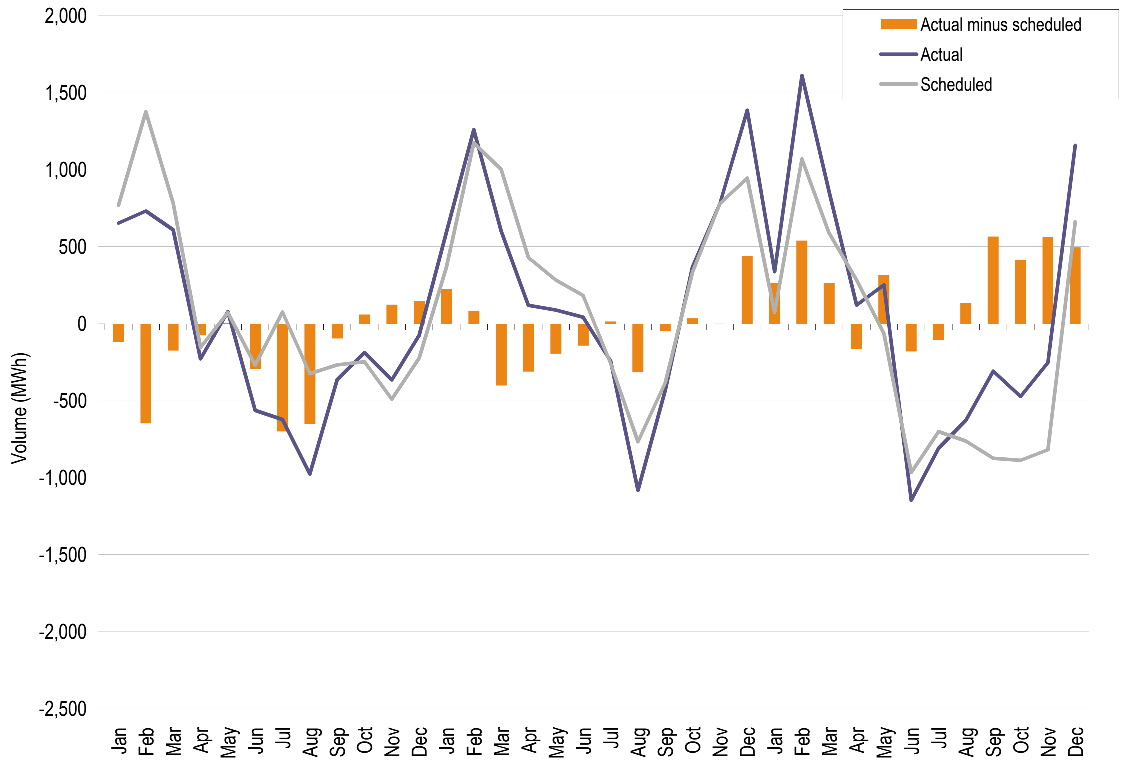


Figure 4-23 Southeast actual and scheduled flows: Calendar years 2006 to 2008



Loop Flows at PJM's Northern Interfaces

In 2008, new loop flows were created when pricing rules gave participants an incentive to schedule power flows in a manner inconsistent with the associated actual power flows. In 2008, market participants scheduled transactions on a path from the NYISO to PJM through Ontario's Independent Electricity System Operator (IESO) and Midwest ISOsystems, rather than reflecting the actual power flows which were primarily directly from NYISO to PJM. The participants faced a price incentive to engage in this behavior. When export transactions were scheduled from NYISO to Ontario, participants paid the lower export price at NYISO's Ontario interface rather than the higher export price at NYISO's PJM interface. The export price differences were more than enough to cover the cost of transmission through Ontario and MISO into PJM. When the export transactions were approved in the NYISO hourly market, the NYISO committed additional generation to support the transactions. The actual flow of energy that resulted was primarily directly from NYISO to PJM across the PJM/NYISO Interface. PJM's interface pricing calculations correctly reflected the actual power flows but NYISO's interface pricing did not. One result was increased congestion charges in the NYISO system. PJM's interface pricing rules eliminated the incentive to schedule power flows on paths inconsistent with actual power flows in order to take advantage of price differences. In this case, PJM interface pricing rules resulted in PJM paying for the import based on its source in the NYISO and disregarded the scheduled path.

On July 21, 2008, the NYISO submitted to FERC an Exigent Circumstances Filing to address this issue.[40] The purpose of the filing was to provide the NYISO the authority to prevent market participants from submitting bids on a set of specific paths associated with the identified scheduling issue. The MMU submitted comments in that proceeding on November 10, 2008, noting that the NYISO's approach to interface pricing is based on the identified fictional scheduled contract paths and do not recognize the actual power flows. The MMU also requested that the Commission condition its approval on a requirement that NYISO work with PJM to develop a more complete solution for interface pricing, congestion management and transmission planning at the NYISO-PJM Interface, within a defined time frame.[41] PJM filed similar comments.[42] By order issued November 17, 2008, the Commission approved NYISO's filing, but required NYISO "to file a status report on its progress in developing solutions to the loop flow problem, including an inter-RTO congestion management process."[43] The NYISO recently filed a report to comply on February 17, 2009.[44] The MMU plans to work with NYISO and PJM to seek a comprehensive solution to this issue.

Data Required for Full Loop Flow Analysis

A complete analysis of loop flow across the Eastern Interconnection could enhance overall market efficiency and shed light on the interactions among market and non market areas. This is important because loop flows have negative impacts on the efficiency of market prices in markets with explicit locational pricing and can be evidence of attempts to game such markets. Loop flows also have poorly understood impacts on non market areas. More broadly, a complete analysis of loop flow could advance the overall transparency of electricity transactions. The term non market area is a misnomer in the sense that all electricity transactions are part of the broad energy market in the Eastern Interconnection. There are areas with transparent markets and there are areas with less transparent markets, but these areas together comprise a market and overall market efficiency would benefit from the increased transparency that would derive from a better understanding of loop flow.

PJM and Midwest ISO issued a joint loop flow report in 2007 that made three recommendations including the establishment of an energy schedule tag archive.[45] The archive would capture and retain data for the entire Eastern Interconnection including tag impact, generation to load impact and market flow impact data for flowgates in the IDC. The archive would be a prime source of information needed to perform after the fact analyses and reviews. The second phase of the joint loop flow study was completed in 2008.[46] In the second phase study, the development of the archive was abandoned due to issues in acquiring IDC data. Instead, the Transmission Adequacy and Reliability Assessment (TARA), an analysis tool that can calculate generation to load impacts, was developed. This tool, while effective in further understanding the sources of loop flows, does not permit a complete analysis of interconnect wide loop flows due to the limited granularity of data.

40 *New York Independent System Operator, Inc.*, Tariff Filing, Docket No. ER08-1281-000 (July 21, 2008).

41 Motion to Intervene and Comments of the Independent Market Monitor for PJM, filed in Docket No. ER09-198, et al. at 2–3. A complete copy of this pleading is posted on Monitoring Analytics' Website at: http://www.monitoringanalytics.com/reports/Reports/2008/filing-motion-to-intervene-comments-er09-198-as-filed.pdf

42 A copy of this filing is posted on PJM's Website at: http://www.pjm.com/Media/documents/ferc/2008-filings/20081110-er09-198-001.pdf

43 *New York Independent System Operator, Inc.*, 125 FERC ¶ 61,184 at P 20.

44 A copy of the report is posted on the NYISO Website at: http://www.nyiso.com/public/webdocs/documents/regulatory/filings/2009/02/NYISOreport2_17_09FNL.pdf.

45 See "Investigation of Loop Flows Across Combined Midwest ISO AND PJM Footprint" (May 25, 2007) (Accessed February 15, 2008) <http://www.jointandcommon.com/working-groups/joint-and-common/downloads/20070525-loop-flow-investigation-report.pdf> (2,597 KB).

46 See "Loop Flow Phase II Study Report – Final" (November 14,2008) (Accessed February 4, 2009) http://www.jointandcommon.com/working-groups/joint-and-common/downloads/20081114-loop-flow-phase-ii-study-report-final-20081112.pdf (3,022 KB).

PJM and Midwest ISO also submitted a memorandum to a NAESB committee reiterating and elaborating the recommendation suggesting a process for determining the allocation of responsibility for congestion relief.[47] The NAESB committee included in their annual plan a commitment to work with NERC on the congestion management issue.[48] As the annual plan states, this is an action item scheduled for completion in 2009.

The MMU recommends that PJM and Midwest ISO reiterate their initial recommendation to create an energy schedule tag archive, as this would provide the transparency necessary for a complete loop flow analysis. The data required for a meaningful loop flow analysis include tag data, market flow impacts data, actual flowgate flows data and balancing authority ACE data for the Eastern Interconnection. The MMU recommends that the RTOs request action, and that both NERC and FERC consider taking the action required to make these data available to the RTOs and market monitors to make a full market analysis possible.

47 See "Annual Plan Item: Determine Future Path for TLR in Concert with NERC" (October 24, 2007) (Accessed February 23, 2009) <http://www.naesb.org/pdf3/weq_aplan102907w1.pdf> (26 KB).

48 See "North American Energy Standards Board, 2008 WEQ Annual Plan Adopted by the Board of Directors on December 13, 2007" (December 13, 2007) (Accessed February 23, 2009) <http://www.naesb.org/pdf3/weq_2008_annual_plan.doc> (281 KB).

SECTION 5 – CAPACITY MARKET

Each organization serving PJM load must meet its capacity obligations by acquiring capacity resources through the PJM Capacity Market where load serving entities (LSEs) must pay the locational capacity price for their zone. LSEs can affect the financial consequences of purchasing capacity in the capacity market by constructing generation and offering it into the capacity market, by developing demand-side resources and offering them into the capacity market, or constructing transmission upgrades and offering them into the capacity market.

Overview

The Market Monitoring Unit (MMU) analyzed market structure, participant conduct and market performance in the PJM Capacity Market for calendar year 2008, including supply, demand, concentration ratios, pivotal suppliers, volumes, prices, outage rates and reliability.

RPM Capacity Market

Market Design

On June 1, 2007, the RPM Capacity Market design was implemented in the PJM region, replacing the CCM Capacity Market design that had been in place since 1999.[1] The RPM design represents a significant change in the structure of the Capacity Market in PJM. The RPM is a forward-looking, annual, locational market, with a must-offer requirement for capacity and mandatory participation by load, with performance incentives for generation, that includes clear, market power mitigation rules and that permits the direct participation of demand-side resources.

Under RPM, capacity obligations are annual. Base Residual Auctions (BRA) are held for delivery years that are three years in the future. First, Second and Third Incremental RPM Auctions may be held for each delivery year, occurring 23, 13 and four months, respectively, prior to the delivery year. RPM prices are locational and may vary depending on transmission constraints.[2] Existing generation capable of qualifying as a capacity resource must be offered into RPM Auctions, except for the fixed resource requirement (FRR) option. Under RPM, participation by LSEs is mandatory, except for the FRR option. Under RPM, there is an administratively determined demand curve that defines scarcity pricing levels and that, with the supply curve derived from capacity offers, determines market prices in each BRA. Under RPM there are performance incentives for generation. Under RPM there are explicit market power mitigation rules that define the must offer requirement, that define structural market power, that define offer caps based on the marginal cost of capacity and that do not limit prices offered by new entrants. Under RPM, demand-side resources may be offered directly into RPM auctions and receive the clearing price.

1 The terms *PJM Region*, *RTO Region* and *RTO* are synonymous in the *2008 State of the Market Report*, Volume II, Section 5, "Capacity Market" and include all capacity within the PJM footprint.

2 Transmission constraints are local capacity import capability limitations (low capacity emergency transfer limit (CETL) margin over capacity emergency transfer objective (CETO)) caused by transmission facility limitations, voltage limitations or stability limitations.

Market Structure

- **Supply.** Total internal capacity increased 1,762.0 MW from 155,206.0 MW on June 1, 2007, to 156,968.0 MW on June 1, 2008.[3] This increase was the result of 89.4 MW of new generation, 112.6 MW from resources which came out of retirement, and 146.2 MW from generation uprates. DR offers increased 595.3 MW. Improvements in the net equivalent demand forced outage rate (EFORd) effect added 818.5 MW.

  In the 2009/2010, 2010/2011 and 2011/2012 auctions, new generation increased 3,049.8 MW; 651.9 MW came out of retirement and net generation deratings were 1,407.7 MW, for a total of 2,294.0 MW. DR offers increased 948.7 MW through June 1, 2011 offset in part by 328.0 MW from higher EFORds. The net effect from June 1, 2008, through June 1, 2011, was an increase in total internal capacity of 2,914.7 MW (1.9 percent) from 156,968.0 MW to 159,882.7 MW.

  In the 2008/2009 auction, 15 more generating resources made offers than in the 2007/2008 RPM Auction. The increase included five new wind resources (66.1 MW), three new diesel resources (23.3 MW) and two resources (112.6 MW) which came out of retirement while the remaining five resources were the result of a reclassification of external resources.

  In the 2009/2010 auction, 17 more generating resources made offers than in the 2008/2009 RPM Auction. The increase included eight new combustion turbine (CT) resources (380.2 MW), two new diesel resources (9.2 MW) and one new steam resource (49.8 MW) while the remaining six resources included more resources imported, fewer resources exported, a decrease in resources excused from offering into the auction and fewer resources removed from the auction under the fixed resource requirement (FRR) option.

  In the 2010/2011 auction, 11 more generating resources made offers than in the 2009/2010 RPM auction. The net increase of 11 resources consisted of 15 new resources, four reactivated resources and three resources from the FRR participant, offset by three retired resources, four deactivated resources, three resources exported from PJM and one resource excused from offering. There were seven new CT resources (270.5 MW), three new diesel resources (16.4 MW), five new wind resources (120.0 MW) and four reactivated resources (165.0 MW) for a total of 19 resources. There were three resources that retired (358.3 MW), four resources that were deactivated (52.9 MW) and an additional three resources exported out of PJM (521.5 MW) for a total of 10 resources.

  In the 2011/2012 auction, 21 more generating resources made offers than in the 2010/2011 RPM auction. The net increase of 21 resources consisted of 20 new resources (2,203.7 MW), four reactivated resources (486.9 MW), three fewer excused resources (126.3 MW), and one additional resource imported (663.2 MW), offset by five additional FRR resources (64.2 MW) and two retired resources (85.8 MW). The new resources consisted of 11 new CT resources (728.7 MW), four new wind resources (75.2 MW), two new steam resources (838.0 MW), one new combined cycle resource (556.5 MW), one new diesel resource (4.2 MW) and one new solar resource (1.1 MW).

3 Unless otherwise specified, all volumes are in terms of UCAP.

- **Demand.** There was a 2,657.3 MW increase in the RPM reliability requirement from 148,277.3 MW on June 1, 2007 to 150,934.6 MW on June 1, 2008. On June 1, 2008, PJM EDCs and their affiliates maintained an 80.1 percent market share of load obligations under RPM, up from 77.5 percent on June 1, 2007.

- **Market Concentration.** For the 2008/2009, 2009/2010, 2010/2011, and 2011/2012 RPM Auctions, all defined markets failed the preliminary market structure screen (PMSS). In each BRA all participants in the total PJM market as well as the locational deliverability area (LDA) markets failed the three pivotal supplier (TPS) market structure test. The result was that offer caps were applied to all sell offers in all auctions. In the 2008/2009 Third Incremental Auction, 22 of 40 participants in the RTO/EMAAC RPM market and all three participants in the SWMAAC RPM market failed the market structure test. Offer caps were applied to those sellers that failed the test.

- **Imports and Exports.** Net exchange decreased 248.5 MW from June 1, 2007 to June 1, 2008. Net exchange, which is imports less exports, decreased due to a decrease in exports of 100.4 MW and a larger decrease in imports of 348.9 MW.

- **Demand-Side Resources.** Under RPM, demand-side resources in the Capacity Market, a combination of DR cleared in the RPM Auctions and certified/forecast interruptible load for reliability (ILR), increased by 2,403.6 MW from 1,763.9 MW on June 1, 2007 to 4,167.5 MW on June 1, 2008.

- **Net Excess.** Net excess decreased 229.42 MW from 5,240.5 MW on June 1, 2007 to 5,011.1 MW on June 1, 2008.

Market Conduct

- **2008/2009 RPM Base Residual Auction.** Of the 1,076 generating resources which submitted offers, unit-specific offer caps were calculated for 117 resources (10.9 percent). Offer caps of all kinds were calculated for 567 resources (52.7 percent), of which 399 were based on the technology specific default (proxy) ACR posted by the MMU.

- **2008/2009 RPM Third Incremental Auction.** Of the 327 generating resources which submitted offers, unit-specific offer caps were calculated for 24 resources (7.3 percent). Offer caps of all kinds calculated for 170 resources (51.9 percent), of which 123 were based on the technology specific default (proxy) ACR posted by the MMU.

- **2009/2010 RPM Base Residual Auction.** Of the 1,093 generating resources which submitted offers, unit-specific offer caps were calculated for 151 resources (13.8 percent). Offer caps of all kinds were calculated for 550 resources (50.3 percent), of which 377 were based on the technology specific default (proxy) ACR posted by the MMU.

- **2010/2011 RPM Base Residual Auction.** Of the 1,104 generating resources which submitted offers, unit-specific offer caps were calculated for 154 resources (13.9 percent). Offer caps of all kinds were calculated for 532 resources (48.1 percent), of which 370 were based on the technology specific default (proxy) ACR posted by the MMU.

- **2011/2012 RPM Base Residual Auction.** Of the 1,125 generating resources which submitted offers, unit-specific offer caps were calculated for 145 resources (12.9 percent). Offer caps of all kinds were calculated for 472 resources (42.0 percent), of which 301 were based on the technology specific default (proxy) ACR posted by the MMU.

Market Performance

2008/2009 RPM Base Residual Auction

- **RTO.** Total internal RTO unforced capacity of 156,968.0 MW includes all generating units and DR that qualified as a PJM capacity resource for the 2008/2009 RPM base residual auction, excludes external units and reflects owners' modifications to installed capacity (ICAP) ratings. Including FRR, committed resources and imports, RPM capacity was 136.237.3 MW. The 129,597.6 MW of cleared resources for the entire RTO represented a reserve margin of 17.5 percent, which was 1,403.0 MW greater than the reliability requirement of 128,194.6 MW (installed reserve margin (IRM) of 15.0 percent) and resulted in a clearing price of $111.92 per MW-day.

  Total cleared resources in the RTO were 129,597.6 MW which resulted in a net excess of 5,011.1 MW, a decrease of 229.4 MW from the net excess of 5,240.5 MW in the 2007/2008 RPM base residual auction. Certified interruptible load for reliability (ILR) was 3,608.1 MW.

  Cleared resources across the entire RTO will receive a total of $6.1 billion based on the unforced MW cleared and the prices in the 2008/2009 RPM BRA, an increase of approximately $1.8 billion from the 2007/2008 planning year.

- **EMAAC.**[4] Total internal EMAAC unforced capacity of 31,379.1 MW includes all generating units and DR that qualified as a PJM capacity resource, excludes external units and reflects owners' modifications to ICAP ratings. Including imports into EMAAC, RPM unforced capacity was 31,396.7 MW. Of the 1,549.5 MW of incremental supply, 401.4 MW cleared, which resulted in a resource-clearing price of $148.80 per MW-day.

  Total resources in EMAAC were 38,161.3 MW, which when combined with certified ILR of 622.6 MW resulted in a net excess of 893.2 MW (2.3 percent) greater than the reliability requirement of 37,890.7 MW.

- **SWMAAC.** Total internal SWMAAC unforced capacity of 10,777.1 MW includes all generating units and DR that qualified as a PJM capacity resource, excludes external units and reflects owners' modifications to ICAP ratings. There were no imports from outside PJM into SWMAAC. Of the 290.5 MW of incremental supply, 285.6 cleared, which resulted in a resource-clearing price of $210.11 per MW-day.

4 EMAAC was an acronym for Eastern Mid-Atlantic Area Council and SWMAAC was an acronym for Southwestern Mid-Atlantic Area Council. MAAC no longer exists as its role was taken on by Reliabilty*First* Corporation. EMAAC and SWMAAC are now regions of PJM.

Total resources in SWMAAC were 16,231.2 MW, which when combined with certified ILR of 219.7 MW resulted in a net deficit of 111.0 MW (0.7 percent) less than the reliability requirement of 16,561.9 MW.

2008/2009 RPM Third Incremental Auction

- **RTO.** There were 2,339.4 MW offered into the Third Incremental Auction while buy bids totaled 2,251.8 MW. Cleared volumes in the RTO were 1,011.6 MW, resulting in an RTO clearing price of $10.00 per MW-day. The price was set by the transition adder. The 1,307.2 MW of uncleared volumes can be used as replacement capacity or traded bilaterally.

  Cleared resources across the entire RTO will receive a total of $5.4 million based on the unforced MW cleared and the prices in the 2008/2009 RPM Third Incremental Auction.

- **EMAAC.** Although EMAAC was a constrained LDA in the 2008/2009 BRA, supply and demand curves resulted in a price less than the RTO clearing price. Supply offers in the incremental auction in EMAAC (1,142.8 MW) exceeded EMAAC demand bids (191.0 MW). The result was that all of EMAAC supply which cleared received the RTO clearing price.

- **SWMAAC.** In SWMAAC, 20.6 MW were offered into the auction while buy bids in SWMAAC totaled 237.5 MW. SWMAAC was a constrained LDA for the 2008/2009 delivery year, so the 20.6 MW was the only supply available to meet SWMAAC demand. Since supply was less than demand, the price was set by a vertical extension of the supply curve to meet demand, resulting in a clearing price of $223.85 per MW-day.

Generator Performance

- **Forced Outage Rates.** The average PJM EFORd decreased from 7.3 percent in 2005 to 6.4 percent in 2005 and 2006 and increased to 6.8 percent in 2007 and 7.4 percent in 2008.[5] The increase in EFORd from 2007 to 2008 was the result of increased forced outage rates for steam and nuclear generating units. The forced outage rates are for the entire PJM footprint.

- **Outages Outside of Management Control (OMC).** PJM permits units to use a forced outage rate (XEFORd) for purposes of selling unforced capacity in the Capacity Market, calculated using outages that are designated outside management control. The MMU questions whether the use of the OMC outage designation in this manner is reasonable, particularly given that most of the OMC outages are based on lack of fuel. A forced outage is a forced outage, from the perspective of system reliability, regardless of the cause.

5 Data are for the 12 months ended December 31, 2008, as downloaded from the PJM GADS database on January 23, 2009. Annual EFORd data presented in state of the market reports may be revised based on data submitted after the publication of the reports as generation owners may submit corrections at any time with permission from PJM GADS administrators.

Conclusion

Market Design

The wholesale power markets, in order to be viable, must be competitive and they must provide adequate revenues to ensure an incentive to invest in new capacity. A wholesale energy market will not consistently produce competitive results in the absence of local market power mitigation rules. This is the result, not of a fundamental flaw in the market design, but of the fact that transmission constraints in a network create local markets where there is structural market power. A wholesale energy market will not consistently result in adequate revenues in the absence of a carefully designed and comprehensive approach to scarcity pricing. This is a result, not of offer capping, but of the fundamentals of wholesale power markets which must carry excess capacity in order to meet externally imposed reliability rules.

Scarcity revenues to generation owners can come entirely from energy markets or they can come from a combination of energy and capacity markets. The RPM design reflects the recognition that the energy markets, by themselves and in the absence of a carefully designed expansion of scarcity pricing, will not result in adequate revenues. The RPM design provides an alternate method for collecting scarcity revenues. The revenues in the capacity market are scarcity revenues.

If the revenues collected in the RPM market are adequate, it is not essential that a scarcity pricing mechanism exist in the energy market. Nonetheless, it would be preferable to also have a scarcity pricing mechanism in the energy market because it provides direct, market-based incentives to load and generation, as long as it is designed to ensure that scarcity revenues directly offset RPM revenues. This hybrid approach would include both a capacity market and scarcity pricing in the energy market.

The definition of the capacity product is central to refining the market rules governing the sale and purchase of capacity. The current definition of capacity includes several components: the obligation to offer the energy of the unit into the day ahead market; the obligation to permit PJM to recall the energy from the unit under emergency procedures; the obligation to provide outage data to PJM; the obligation to provide energy during the defined high demand hours each year; and the obligation that the energy output from the resource be deliverable to load in PJM.

The most critical of these components of the definition of capacity is the obligation to offer the energy of the unit into the day ahead market. If buyers are to pay the high prices associated with RPM, it must be clear what they are buying and what the obligations of the sellers are. The fundamental energy market design should assure all market participants that the outcomes are competitive. This works to the ultimate advantage of all market participants including existing and prospective load and existing and prospective generation. The market rules should explicitly require that offers into the day ahead energy market be competitive, where competitive is defined to be the short run marginal cost of the units. The short run marginal cost should reflect opportunity cost when and where appropriate.

An offer that exceeds short run marginal cost is not a competitive offer in the day ahead energy market. Such an offer assumes the need to exercise market power to ensure revenue adequacy. An offer to provide energy only in an emergency is not a competitive offer in the day ahead energy market. 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.

Capacity market design should reflect the fact that the capacity market is a mechanism for the collection of scarcity revenues and thus reflect the incentive structure of energy markets to the maximum extent possible. For example, if a generation unit does not produce power during a high price hour, it receives no revenues from the energy market. It does not receive some revenues simply for existing, it receives zero revenues. The reason that the unit does not produce energy is not relevant. It does not receive revenues if it does not produce energy even if the reason for non performance is outside management's control. That is the basic performance incentive structure of energy markets. The same performance incentive structure should be replicated in capacity market design. If a unit that is a capacity resource does not produce energy during the hours defined as critical, it will receive no energy revenues for those hours. If a unit defined as a capacity resource does not produce energy during any of the hours defined as critical, it should receive no capacity revenues. This approach to performance is also consistent with the reduction or elimination of administrative penalties associated with failure to meet capacity tests, for example.

A hybrid market design can provide scarcity revenues both via scarcity pricing in the energy market and via the capacity market. However, if there is scarcity pricing in the energy market, the market design must ensure that units receiving scarcity revenues in the capacity market do not also receive scarcity revenues in the energy market. This would be double payment of scarcity revenues. This offset must reflect the actual scarcity revenues and not those reflected in forward curves or forecasts, or those reflected in results from prior years. Scarcity revenues are episodic and unlikely to be fully reflected in historical data or in forward curves, even if such curves were based on a liquid market three years forward, which they are not, and reflected locational results, which they do not. The most straightforward way to ensure that such double payment does not occur would be to ensure that capacity resources do not receive scarcity revenues in the energy market in the first place. The settlements process can remove any scarcity revenues from payments to capacity resources and eliminate the need for a complex, uncertain, after the fact procedure for offsetting scarcity revenues in the capacity market.

Market Power

The RPM Capacity Market design explicitly addresses the underlying issues of ensuring that competitive prices can reflect local scarcity while not relying on the exercise of market power to achieve the design objective and explicitly limiting the exercise of market power.

The Capacity Market is, by design, always tight in the sense that total supply is generally only slightly larger than demand. The demand for capacity includes expected peak load plus a reserve margin. Thus, the reliability goal is to have total supply equal to, or slightly above, the demand for capacity. The market may be long at times, but that is not the equilibrium state. Capacity in excess of demand is not sold and, if it does not earn adequate revenues in other markets, will retire. Demand is almost entirely inelastic because the market rules require loads to purchase their share of the system capacity requirement. The result is that any supplier that owns more capacity than the difference between total supply and the defined demand is pivotal and has market power.

In other words, the market design for capacity leads, almost unavoidably, to structural market power. Given the basic features of market structure in the PJM Capacity Market, including significant market structure issues, inelastic demand, tight supply-demand conditions, the relatively small number of nonaffiliated LSEs and supplier knowledge of aggregate market demand, the MMU concludes that the potential for the exercise of market power continues to be high. Market power is and will remain endemic to the existing structure of the PJM Capacity Market. This is not surprising in that the Capacity Market is the result of a regulatory/administrative decision to require a specified level of reliability and the related decision to require all load serving entities to purchase a share of the capacity required to provide that reliability. It is important to keep these basic facts in mind when designing and evaluating capacity markets. The Capacity Market is unlikely ever to approach the economist's view of a competitive market structure in the absence of a substantial and unlikely structural change that results in much more diversity of ownership.

RPM has explicit market power mitigation rules designed to permit competitive, locational capacity prices while limiting the exercise of market power. The RPM construct is consistent with the appropriate market design objectives of permitting competitive prices to reflect local scarcity conditions while explicitly limiting market power. The RPM Capacity Market design provides that competitive prices can reflect locational scarcity while not relying on the exercise of market power to achieve that design objective by limiting the exercise of market power via the application of the three pivotal supplier test.

Competitive prices are the lowest possible prices, consistent with the resource costs. But, competitive prices are not necessarily low prices. In the Capacity Market, it is essential that the cost of new entry (CONE) be based on the actual resource costs of bringing a new capacity resource into service. If RPM is to provide appropriate incentives for new entry, the marginal price signal must reflect the actual cost of new entry.

The existence of a capacity market that links payments for capacity to the level of unforced capacity and therefore to the forced outage rate creates an incentive to improve forced outage rates. The performance incentives are stronger in the RPM Capacity Market design although they need further strengthening. The Energy Market also provides incentives for improved performance with somewhat different characteristics. Generators want to maximize their sales of energy when prices are high and if they are successful, this will also result in lower forced outage rates. Well designed scarcity pricing could also provide strong, complementary incentives for reduced outages during high load periods. It would be preferable to rely on strong market-based incentives for capacity resource performance rather than the current structure of penalties, which has its own incentive effects.

Results

The analysis of PJM Capacity Markets begins with market structure, which provides the framework for the actual behavior or conduct of market participants. The analysis examines participant behavior within that market structure. In a competitive market structure, market participants are constrained to behave competitively. The analysis examines market performance, measured by price and the relationship between price and marginal cost, that results from the interaction of market structure and participant behavior.

The MMU found serious market structure issues, but no exercise of market power in the PJM Capacity Market in 2008. Explicit market power mitigation rules in the RPM construct offset the underlying market structure issues in the PJM Capacity Market under RPM. The PJM Capacity Market results were competitive during 2008.

RPM Capacity Market

Market Design

The RPM Capacity Market design was implemented effective June 1, 2007. RPM represents a significant change in the structure of the Capacity Market in PJM. The RPM is a forward-looking, annual, locational market, with a must-offer requirement for capacity and mandatory participation by load, with performance incentives for generation, that includes clear, market power mitigation rules and that permits the direct participation of demand-side resources.

The first four base RPM Auctions comprised the RPM transition period.[6] After this transition period, annual base auctions are held in May for delivery years that are three years in the future. First, Second and Third Incremental RPM Auctions may be held for each delivery year, occurring 23, 13 and four months prior to the delivery year. In 2008, the 2010/2011 BRA was held in January and the 2011/2012 BRA was held in May.[7] A Third Incremental Auction was held in January 2008 for the delivery year 2008/2009.

Market Structure

Supply

As shown in Table 5-1, total internal capacity increased 1,762.0 MW from 155,206.0 MW on June 1, 2007, to 156,968.0 MW on June 1, 2008. This increase was the result of 89.4 MW of new generation, 112.6 MW from resources which came out of retirement, and 146.2 MW from generation uprates. DR offers increased 595.3 MW. The net EFORd effect was 818.5 MW.

In the 2009/2010, 2010/2011 and 2011/2012 auctions, new generation increased 3,049.8 MW; 651.9 MW were brought out of retirement and net generation deratings were 1,407.7 MW, for a total of 2,294.0 MW. DR offers increased 948.7 MW through June 1, 2011 offset in part by 328.0 MW from higher EFORds. The net effect from June 1, 2008, through June 1, 2011, was an increase in total internal capacity of 2,914.7 MW (1.9 percent) from 156,968.0 MW to 159,882.7 MW.

As shown in Table 5-1 and Table 5-7, in the 2008/2009 RPM Auction, the increase of 15 RPM resources included five new wind resources (66.1 MW), three new diesel resources (23.3 MW) and two resources (112.6 MW) which came out of retirement while the remaining five resources

6 For more detailed analysis of the RPM Auctions, see: "Analysis of the 2007/2008 RPM Auction" (August 16, 2007); "Analysis of the 2008/2009 RPM Auction" (November 30, 2007); "Analysis of the 2008/2009 Third Incremental RPM Auction" (June 23, 2008); "Analysis of the 2009/2010 RPM Auction" (November 30, 2007); "Analysis of the 2010-2011 RPM Auction" (May 6, 2008); "Analysis of the 2011/2012 RPM Auction" (September 12, 2008) (Accessed February 20, 2009) <http://www.monitoringanalytics.com/reports/Reports/2008.shtml>.

7 Delivery years are from June 1 through May 31. The 2008/2009 delivery year runs from June 1, 2008, through May 31, 2009.

were the result of a reclassification of external resources.[8] There were 23 DR resources offered compared to 15 DR resources offered in the 2007/2008 RPM Auction.[9]

As also shown in Table 5-1 and Table 5-8, in the 2009/2010 RPM Auction, the increase of 17 RPM resources included eight new CT resources (380.2 MW), two new diesel resources (9.2 MW) and one new steam resource (49.8 MW) while the remaining increase of six resources was the result of a combination of more resources imported, less resources exported, a decrease in resources excused from offering into the auction and fewer resources removed from the auction under the FRR option. There were 38 DR resources offered compared to 23 DR resources offered in the 2008/2009 RPM Auction.

As shown in Table 5-1 and Table 5-8, in the 2010/2011 auction, the increase of 11 RPM resources consisted of 15 new resources, four reactivated resources and three resources from the FRR participant, offset by three retired resources, four deactivated resources, three resources exported from PJM and one resource excused from offering. There were seven new CT resources (270.5 MW), three new diesel resources (16.4 MW), five new wind resources (120.0 MW) and four reactivated resources (165.0 MW) for a total of 19 resources. There were three resources that retired (358.3 MW), four resources that were deactivated (52.9 MW) and an additional three resources exported out of PJM (521.5 MW) for a total of 10 resources. There were 23 demand resources (DR) offered compared to 38 DR resources offered in the 2009/2010 RPM auction.

As also shown in Table 5-1 and Table 5-8, in the 2011/2012 auction, the increase of 21 resources consisted of 20 new resources (2,203.7 MW), four reactivated resources (486.9 MW), three fewer excused resources (126.3 MW), and one additional resource imported (663.2 MW), offset by five additional FRR resources (64.2 MW) and two retired resources (85.8 MW). The new resources consisted of 11 new CT resources (728.7 MW), four new wind resources (75.2 MW), two new steam resources (838.0 MW), one new combined cycle resource (556.5 MW), one new diesel resource (4.2 MW) and one new solar resource (1.1 MW). There were 37 demand resources (DR) offered compared to 23 DR resources offered in the 2010/2011 RPM auction.

8 Certain external hydroelectric units were allocated from the LDA level to the zonal level, resulting in an increased unit count.
9 Some generation and DR resources had multiple associated offers.

Table 5-1 Internal capacity: June 1, 2007, through May 31, 2011[10]

	UCAP (MW)				
	RTO	EMAAC	SWMAAC	MAAC+APS	DPL-South
Total internal capacity @ 01-Jun-07	155,206.0	30,825.1	10,352.2		
New generation	89.4	0.0	0.0		
Units out of retirement	112.6	112.6	0.0		
Generation capmods	146.2	105.9	38.9		
DR mods	595.3	298.7	294.3		
Net EFORd effect	818.5	36.8	91.7		
Total internal capacity @ 01-Jun-08	156,968.0	31,379.1	10,777.1	72,889.5	
New generation	439.2		0.0	109.9	
Units out of retirement	0.0		0.0	0.0	
Generation capmods	74.1		(298.2)	(149.7)	
DR mods	220.6		42.3	163.2	
Net EFORd effect	(383.7)		(176.0)	0.0	
Total internal capacity @ 01-Jun-09	157,318.2		10,345.2	73,012.9	1,587.0
New generation	406.9				0.0
Units out of retirement	165.0				0.0
Generation capmods	1,085.8				(85.5)
DR mods	43.7				15.7
Net EFORd effect	11.3				28.9
Total internal capacity @ 01-Jun-10	159,030.9				1,546.1
New generation	2,203.7				
Units out of retirement	486.9				
Generation capmods	(2,567.6)				
DR mods	684.4				
Net EFORd effect	44.4				
Total internal capacity @ 01-Jun-11	159,882.7				
Reclassification of Duquesne units	3,009.5				
Adjusted internal capacity @ 01-Jun-11	162,892.2				

10 The RTO includes MAAC+APS, EMAAC and SWMAAC. MAAC+APS includes EMAAC and SWMAAC. In the 2009/2010 RPM Auction, EMAAC was not constrained, so results for it are not shown. Maps of the LDAs can be found in the *2008 State of the Market Report*, Appendix A, "PJM Geography."

Demand

There was a 2,657.3 MW increase in the RPM reliability requirement from 148,277.3 MW on June 1, 2007, to 150,934.6 MW on June 1, 2008. This increase resulted from a higher peak-load forecast.

The MMU analyzed market sectors in the PJM Capacity Market to determine how they met their load obligations. The Capacity Market was divided into the following sectors:

- **PJM EDC.** EDCs with a franchise service territory within the PJM footprint. This sector includes traditional utilities, electric cooperatives, municipalities and power agencies.
- **PJM EDC Generating Affiliate.** Affiliate companies of PJM EDCs that own generating resources.
- **PJM EDC Marketing Affiliate.** Affiliate companies of PJM EDCs that sell power and have load obligations in PJM, but do not own generating resources.
- **Non-PJM EDC.** EDCs with franchise service territories outside the PJM footprint.
- **Non-PJM EDC Generating Affiliate.** Affiliate companies of non-PJM EDCs that own generating resources.
- **Non-PJM EDC Marketing Affiliate.** Affiliate companies of non-PJM EDCs that sell power and have load obligations in PJM, but do not own generating resources.
- **Non-EDC Generating Affiliate.** Affiliate companies of non-EDCs that own generating resources.
- **Non-EDC Marketing Affiliate.** Affiliate companies of non-EDCs that sell power and have load obligations in PJM, but do not own generating resources.

On June 1, 2008, PJM EDCs and their affiliates maintained a large market share of load obligations under RPM, together totaling 80.1 percent (Table 5-2), up from 77.5 percent on June 1, 2007. The combined market share of LSEs not affiliated with any EDC and of non-PJM EDC affiliates was 19.9 percent, down from 22.5 percent on June 1, 2007. Obligation is defined as cleared MW plus ILR forecast obligations.

Table 5-2 PJM Capacity Market load obligation served: June 1, 2008

	Obligation (MW)							
	PJM EDCs	PJM EDC Generating Affiliates	PJM EDC Marketing Affiliates	Non-PJM EDC Generating Affiliates	Non-PJM EDC Marketing Affiliates	Non-EDC Generating Affiliates	Non-EDC Marketing Affiliates	Total
Obligation	63,390.7	17,884.1	23,910.3	1,211.4	9,668.5	199.5	14,990.2	131,254.6
Percent of total obligation	48.3%	13.6%	18.2%	0.9%	7.4%	0.2%	11.4%	100.0%

Market Concentration

Preliminary Market Structure Screen

Under the terms of the PJM Tariff, the MMU is required to apply the PMSS prior to RPM BRA Auctions.[11] The results of the PMSS are applicable for the First, Second, and Third Incremental Auctions for a given delivery year.[12] The purpose of the PMSS is to determine whether additional data are needed from owners of capacity resources in the defined areas in order to permit the MMU to apply the market structure tests defined in the Tariff.

An LDA or the RTO Region fails the PMSS if any one of the following three screens is failed: the market share of any capacity resource owner exceeds 20 percent; the HHI for all capacity resource owners is 1800 or higher; or there are not more than three jointly pivotal suppliers.[13]

As shown in Table 5-3, all defined markets failed the PMSS. As a result, capacity resource owners were required to submit avoidable cost rate (ACR) data to the MMU for resources for which they intended to submit nonzero sell offers unless certain other conditions were met.[14]

11 See PJM. "Open Access Transmission Tariff (OATT)," "Attachment DD: Reliability Pricing Model," Original Sheet No. 605 (Effective June 1, 2007), section 6.3 (a) i.
12 See PJM. "Open Access Transmission Tariff (OATT)," "Attachment DD: Reliability Pricing Model," Original Sheet No. 605 (Effective June 1, 2007), section 5.11 (b) i.
13 See PJM. "Open Access Transmission Tariff (OATT)," "Attachment DD: Reliability Pricing Model," Original Sheet No. 605 (Effective June 1, 2007), section 6.3 (a) ii.
14 See PJM. "Open Access Transmission Tariff (OATT)," "Attachment DD: Reliability Pricing Model," First Revised Sheet No. 610 (Effective June 20, 2007), section 6.7 (c).

Table 5-3 Preliminary market structure screen results: 2008/2009 through 2011/2012 RPM Auctions

RPM Markets	Highest Market Share	HHI	Pivotal Suppliers	Pass/Fail
2008/2009				
RTO	18.5%	879	1	Fail
EMAAC	33.1%	2180	1	Fail
SWMAAC	47.5%	4290	1	Fail
2009/2010				
RTO	18.4%	853	1	Fail
SWMAAC	51.1%	4229	1	Fail
MAAC+APS	26.9%	1627	1	Fail
2010/2011				
RTO	18.4%	853	1	Fail
EMAAC	31.3%	2053	1	Fail
SWMAAC	51.1%	4229	1	Fail
MAAC+APS	26.9%	1627	1	Fail
2011/2012				
RTO	18.0%	855	1	Fail

Auction Market Structure

As shown in Table 5-4, all participants in the total PJM market as well as the LDA RPM markets failed the TPS test in each BRA auction.[15] The result was that offer caps were applied to all sell offers. In the 2008/2009 Third Incremental Auction, 22 of 40 participants in the RTO/EMAAC RPM market and all three participants in the SWMAAC RPM market failed the market structure test. Some participants passed the test in the incremental auction as a result of the substantially different structure of incremental supply. Offer caps were applied to those sellers that failed the test. The RTO market includes all supply which cleared at or below the unconstrained clearing price. The LDA markets include the incremental supply in the LDAs which was required to meet the demand for capacity in each LDA and which cleared at a price higher than the unconstrained price.

15 The market definition used for the TPS test includes all offers with costs less than or equal to 1.50 times the clearing price. See the *2008 State of the Market Report*, Appendix L, "Three Pivotal Supplier Test" for additional discussion.

Table 5-4 RSI results: 2008/2009 through 2011/2012 RPM Auctions

RPM Markets	RSI_3	Total Participants	Failed RSI_3 Participants
2008/2009 BRA			
RTO	0.61	65	65
EMAAC	0.25	10	10
SWMAAC	0.00	3	3
2008/2009 Third IA			
RTO/EMAAC	0.87	40	22
SWMAAC	0.00	3	3
2009/2010 BRA			
RTO	0.60	66	66
MAAC+APS	0.37	21	21
SWMAAC	0.00	3	3
2010/2011 BRA			
RTO	0.60	68	68
DPL-South	0.00	2	2
2011/2012 BRA			
RTO	0.63	76	76

Imports and Exports

As shown in Table 5-5, net exchange decreased 248.5 MW from June 1, 2007 to June 1, 2008. Net exchange, which is imports less exports, decreased due to a decrease in exports of 100.4 MW and a larger decrease in imports of 348.9 MW.

Table 5-5 PJM capacity summary (MW): June1, 2007, through May 31, 2011[16]

	01-Jun-07	01-Jun-08	01-Jun-09	01-Jun-10	01-Jun-11
Installed capacity (ICAP)	163,721.1	164,444.1	166,916.0	168,061.5	172,666.6
Unforced capacity	154,076.7	155,590.2	157,628.7	158,634.2	163,144.3
Cleared capacity	129,409.2	129,597.6	132,231.8	132,190.4	132,221.5
RPM reliability requirement (pre-FRR)	148,277.3	150,934.6	153,480.1	156,636.8	154,251.1
RPM reliability requirement (less FRR)	125,805.0	128,194.6	130,447.8	132,698.8	130,658.7
RPM net excess	5,240.5	5,011.1	3,403.3	1,149.2	3,156.6
Imports	2,809.2	2,460.3	2,505.4	2,750.7	6,420.0
Exports	(3,938.5)	(3,838.1)	(2,194.9)	(3,147.4)	(3,158.4)
Net exchange	(1,129.3)	(1,377.8)	310.5	(396.7)	3,261.6
DR cleared	127.6	536.2	892.9	939.0	1,364.9
ILR	1,636.3	3,608.1	2,107.5	2,110.5	1,593.8
FRR DR	445.6	452.8	488.2	452.9	452.9

Demand-Side Resources

Under the PJM load management (LM) program, qualifying load management resources can be offered into RPM Auctions as capacity resources and receive the clearing price, or they can be offered outside of the auction and receive the final, zonal ILR price.

The LM program introduced two RPM-related products. DR resources are load resources that are offered into an RPM Auction as capacity and receive the relevant LDA or RTO clearing price. ILR resources are load resources that are not offered into the RPM Auction, but receive the final, zonal ILR price determined after the close of the second incremental auction.

Under RPM, DR resources must be offered into the auction for the delivery year during which they will participate while ILR resources must be certified by a published deadline which is after the Base Residual Auction for the delivery year but at least three months prior to the delivery year during which they will participate.

As shown in Table 5-6, capacity in the RPM load management programs, which is a combination of DR cleared in the RPM Auctions and certified/forecast ILR, increased by 2,403.6 MW from 1,763.9 MW on June 1, 2007 to 4,167.5 MW on June 1, 2008. Final ILR is certified three months before the delivery year and it may differ from the ILR forecast.

16 FRR DR values have been revised since the *2007 State of the Market Report* was posted.

Table 5-6 RPM load management statistics: June 1, 2007 through May 31, 2011[17]

	UCAP (MW)				
	RTO	EMAAC	SWMAAC	MAAC+APS	DPL-South
DR cleared	127.6	44.7	19.7		
ILR certified	1,636.3	387.0	273.4		
RPM load management @ 01-June-2007	1,763.9	431.7	293.1		
DR cleared	559.4	169.0	309.2		
ILR certified	3,608.1	622.6	219.7		
RPM load management @ 01-June-2008	4,167.5	791.6	528.9		
DR cleared	892.9		356.3	813.9	
ILR forecast - FRR DR	1,619.3		345.7	1,055.7	
RPM load management @ 01-June-2009	2,512.2		702.0	1,869.6	
DR cleared	939.0				14.9
ILR forecast - FRR DR	1,657.6				22.2
RPM load management @ 01-June-2010	2,596.6				37.1
DR cleared	1,364.9				
ILR forecast	1,593.8				
RPM load management @ 01-June-2011	2,958.7				

Market Conduct

Offer Caps

If a capacity resource owner failed the market power test for the auction, avoidable costs were used to calculate offer caps for that owner's resources. Avoidable costs are the costs that a generation owner would not incur if the generating unit did not operate for one year, in particular the delivery year.[18] In effect, avoidable costs are the costs that a generation owner would not incur if the generating unit were mothballed for the year. In the calculation of avoidable costs, there is no presumption that the unit would retire as the alternative to operating, although that possibility could be reflected if the owner documented that retirement was the alternative. Avoidable costs also include annual capital recovery associated with investments required to maintain a unit as a capacity resource. This component of avoidable costs is termed the avoidable project investment recovery rate (APIR). Avoidable costs are the defined costs less net revenues from all other PJM

17 PJM used forecast ILR, including FRR DR, for the first four base residual auctions. For 2007/2008 and 2008/2009, certified ILR data were used in the calculation here because the certified ILR data are now available. For 2009/2010 and 2010/2011, forecast ILR less FRR DR is used and will continue to be used until certified ILR data are available. PJM used forecast ILR, excluding FRR DR, for the 2011/2012 BRA. Therefore, FRR DR is not subtracted in the calculation here for the 2011/2012 auction.

18 See PJM. "Open Access Transmission Tariff (OATT)," "Attachment DD: Reliability Pricing Model," Original Sheet No. 617 (Effective June 1, 2007), section 6.8 (b).

markets and from unit-specific bilateral contracts. The specific components of avoidable costs are defined in the PJM Tariff.

Capacity resource owners could provide ACR data by providing their own unit-specific data, by selecting the default ACR values calculated by the MMU, by submitting an opportunity cost for a possible export, by inputting a transition adder or by using combinations of these options. The opportunity cost option for exports allows resource owners to input a documented export price as the opportunity cost offer for the unit. If the relevant RPM market clears above the opportunity cost, the unit's capacity is sold in the RPM market. If the opportunity cost is greater than the clearing price, the unit's capacity does not clear in the RPM market and it is available for export. The transition adder was added to the offer cap, if appropriate, regardless of the offer-cap calculation method.[19]

Table 5-7 ACR statistics: 2008/2009 RPM Auctions

	2008/2009 BRA		2008/2009 Third IA	
Calculation Type	Number of Resources	Percent of Generating Resources Offered	Number of Resources	Percent of Generating Resources Offered
Default ACR selected	399	37.1%	123	37.6%
ACR data input (non-APIR)	37	3.4%	8	2.4%
ACR data input (APIR)	80	7.4%	16	4.9%
Opportunity cost input	8	0.7%	3	0.9%
Transition adder only	43	4.0%	20	6.1%
Offer caps calculated	567	52.6%	170	51.9%
Uncapped new units	0	0.0%	3	0.9%
Generator price takers	509	47.4%	154	47.2%
Generating units offered	1,076	100.0%	327	100.0%
Demand resources offered	23		9	
Total capacity resources offered	1,099		336	

19 The transition adder, which is added to the calculated offer cap, is $10.00 per MW-day for delivery years 2007/2008 and 2008/2009 and $7.50 per MW-day for delivery year 2009/2010. It can be applied only up to 3,000 MW of unforced capacity per owner, only in unconstrained markets and only by those parent companies which own no more than 10,000 MW of unforced capacity in PJM.

Table 5-8 ACR statistics: 2009/2010 through 2011/2012 RPM Base Residual Auctions

	2009/2010 BRA		2010/2011 BRA		2011/2012 BRA	
Calculation Type	Number of Resources	Percent of Generating Resources Offered	Number of Resources	Percent of Generating Resources Offered	Number of Resources	Percent of Generating Resources Offered
Default ACR selected	377	34.5%	370	33.5%	301	26.8%
ACR data input (non-APIR)	22	2.0%	20	1.8%	12	1.1%
ACR data input (APIR)	129	11.8%	134	12.1%	133	11.8%
Opportunity cost input	10	0.9%	8	0.7%	26	2.3%
Transition adder only	12	1.1%	N/A		N/A	
Offer caps calculated	550	50.3%	532	48.1%	472	42.0%
Uncapped new units	3	0.3%	15	1.4%	20	1.8%
Generator price takers	540	49.4%	557	50.5%	633	56.2%
Generating units offered	1,093	100.0%	1,104	100.0%	1,125	100.0%
Demand resources offered	38		23		37	
Total capacity resources offered	1,131		1,127		1,162	

Table 5-9 APIR statistics: 2008/2009 through 2011/2012 RPM Auctions[20,21]

		Weighted-Average ($ per MW-day UCAP)						
		Combined Cycle	Combustion Turbine	Oil or Gas Steam	SubCritical/ SuperCritical Coal	Other	Opportunity Costs	Total
2008/2009 BRA								
Non-APIR units	ACR	$38.81	$24.59	$70.24	$151.50	$76.66		$86.25
	Net revenues	$61.58	$21.17	$25.62	$362.48	$496.75		$184.49
	Offer caps	$17.14	$13.33	$45.63	$9.14	$4.30	$106.44	$20.45
APIR units	ACR	$40.64	$18.08	$121.39	$297.81	$27.61		$129.96
	Net revenues	$99.11	$19.60	$20.19	$202.87	$15.76		$89.95
	Offer caps	$4.70	$4.60	$101.20	$109.96	$21.85		$58.46
	APIR	$0.80	$4.92	$28.47	$131.38	$15.54		$49.29
	Maximum APIR effect							$211.28
2008/2009 Third IA								
Non-APIR units	ACR	$28.56	$23.93	$60.76	$149.73	$41.06		$71.67
	Net revenues	$27.74	$17.21	$16.20	$353.71	$355.75		$127.86
	Offer caps	$20.75	$14.99	$52.02	$12.82	$9.37	$162.37	$27.31
APIR units	ACR	$112.16	$10.18	$142.97	$341.45	NA		$259.45
	Net revenues	$251.21	$15.58	$22.34	$177.77	NA		$136.18
	Offer caps	NA	$1.63	$120.62	$163.68	NA		$132.74
	APIR	$0.56	$2.55	$33.44	$165.40	NA		$113.75
	Maximum APIR effect							$209.26
2009/2010 BRA								
Non-APIR units	ACR	$37.74	$26.07	$80.09	$159.26	$84.07		$82.66
	Net revenues	$61.97	$23.08	$31.92	$321.88	$516.72		$162.48
	Offer caps	$14.76	$13.51	$49.81	$11.44	$1.36	$123.60	$26.32
APIR units	ACR	$58.12	$43.83	$129.59	$525.98	$30.71		$285.17
	Net revenues	$97.94	$16.10	$19.71	$322.91	$15.75		$172.57
	Offer caps	$17.93	$30.45	$109.88	$164.31	$22.45		$102.07
	APIR	$0.24	$22.86	$43.79	$386.13	$18.96		$195.85
	Maximum APIR effect							$383.79
2010/2011 BRA								
Non-APIR units	ACR	$34.39	$27.10	$67.57	$167.08	$82.55		$80.86
	Net revenues	$96.75	$18.81	$15.19	$302.79	$391.00		$151.31
	Offer caps	$10.13	$14.12	$52.38	$9.67	$4.53	$124.60	$20.98
APIR units	ACR	$61.61	$49.26	$290.64	$630.85	$34.62		$360.27
	Net revenues	$26.84	$10.32	$83.61	$535.68	$2.07		$263.27
	Offer caps	$37.30	$39.41	$207.04	$123.85	$32.55		$110.25
	APIR	$9.87	$30.93	$198.78	$494.87	$22.42		$272.18
	Maximum APIR effect							$577.03
2011/2012 BRA								
Non-APIR units	ACR	$39.52	$30.17	$72.20	$181.52	$62.54		$75.86
	Net revenues	$69.04	$20.16	$17.27	$466.41	$322.78		$173.54
	Offer caps	$11.76	$16.42	$62.13	$7.88	$11.50	$182.41	$45.80
APIR units	ACR	$61.66	$56.28	$307.18	$709.11	$36.03		$424.49
	Net revenues	$78.17	$10.35	$82.14	$542.90	$2.06		$286.80
	Offer caps	$34.69	$46.18	$225.04	$178.79	$33.97		$147.77
	APIR	$11.82	$37.28	$213.50	$560.20	$24.68		$324.58
	Maximum APIR effect							$523.26

20 The weighted-average offer cap can still be positive even when the weighted-average net revenues are higher than the weighted-average ACR due to the offer-cap minimum being zero. On a unit basis, if net revenues are greater than ACR, net revenues in an amount equal to the ACR are used in the calculation and the offer cap is zero.

21 This table has been updated since the MMU RPM Auction reports were posted.

2008/2009 RPM Base Residual Auction

As shown in Table 5-7, 1,076 generating resources submitted offers into the 2008/2009 RPM BRA as compared to the 1,061 generating resources offered in the 2007/2008 RPMBRA. Unit-specific offer caps were calculated for 117 resources (10.8 percent). Offer caps of all kinds were calculated for 567 resources (52.6 percent), of which 399 were based on the technology specific default (proxy) ACR posted by the MMU. Of the 1,076 generating resources, the remaining 509 resources were price takers, of which the offers for 472 resources were zero and the offers for 37 resources were set to zero because no data were submitted. The transition adder was part of the offers on 255 resources, of which offers on 43 resources included only the transition adder. The transition adder had no impact on the clearing prices.

Of the 1,076 generating resources which submitted offers, 80 (7.4 percent) included an APIR component. (See Table 5-7.) As shown in Table 5-9, the weighted averages for resources with APIR for ACR ($129.96 per MW-day) and offer caps ($58.46 per MW-day) were higher than the ACR ($86.25 per MW-day) and offer caps ($20.45 per MW-day) for resources without an APIR component, including resources for which the default value was selected. The APIR component added $49.29 per MW-day to the ACR value of the APIR resources.[22] The default ACR values include an average APIR of $0.91 per MW-day. The highest APIR for a technology ($131.38 per MW-day) was for subcritical/supercritical coal resources. The maximum APIR effect ($211.28 per MW-day) is the maximum amount by which an offer cap was increased by APIR.

2008/2009 RPM Third Incremental Auction

As shown in Table 5-7, 327 generating resources and nine demand resources submitted offers in the 2008/2009 RPM Third Incremental Auction. Unit-specific offer caps were calculated for 24 resources (7.3 percent). Offer caps of all kinds were calculated for 170 resources (51.9 percent), of which 123 (37.6 percent) were based on the technology specific default (proxy) ACR posted by the MMU. Three new generation resources had uncapped offers while the remaining 154 generation resources were price takers. The transition adder was part of the offers on 90 resources, of which offers on 20 resources included only the transition adder. All of the 14 resources which were marginal at $10.00 per MW-day had the transition adder as their offer caps.

Of the 327 generating resources which submitted offers, 16 (4.9 percent) included an APIR component. (See Table 5-7.) As shown in Table 5-9, the weighted-averages for resources with APIR for ACR ($259.45 per MW-day) and offer caps ($132.74 per MW-day) were higher than the ACR ($71.67 per MW-day) and offer caps ($27.31 per MW-day) for resources without an APIR component, including resources for which the default value was selected. The APIR component added $113.75 per MW-day to the ACR value of the APIR resources. The default ACR values include an average APIR of $0.91 per MW-day. The highest APIR for a technology ($165.40 per MW-day) was for subcritical/supercritical coal resources. The maximum APIR effect ($209.26 per MW-day) is the maximum amount by which an offer cap was increased by APIR.

22 Of the 80 units which had an APIR component, 77 units had current year capital dollars submitted of $421.1 million on 7,234.9 MW UCAP. Three units had APIR based on the inclusion of 2007/2008 capital projects.

2009/2010 RPM Base Residual Auction

As shown in Table 5-8, 1,093 generating resources submitted offers in the 2009/2010 RPM Auction as compared to 1,076 generating resources offered in the 2008/2009 RPM Auction. Unit-specific offer caps were calculated for 151 resources (13.8 percent). Offer caps of all kinds were calculated for 550 resources (50.3 percent), of which 377 were based on the technology specific default (proxy) ACR posted by the MMU. Three new generation resources had uncapped offers while the remaining 540 generation resources were price takers, of which the offers for 514 resources were zero and the offers for 26 resources were set to zero because no data were submitted.[23] The transition adder was part of the offers on 206 resources, of which offers on 12 resources included only the transition adder. The transition adder had no impact on the clearing prices.

Of the 1,093 generating resources which submitted offers, 129 (11.8 percent) included an APIR component. (See Table 5-8.) As shown in Table 5-9, the weighted-averages for resources with APIR for ACR ($285.17 per MW-day) and offer caps ($102.07 per MW-day) were higher than the ACR ($82.66 per MW-day) and offer caps ($26.32 per MW-day) for resources without an APIR component, including resources for which the default value was selected. The APIR component added $195.85 per MW-day to the ACR value of the APIR resources.[24] The default ACR values include an average APIR of $0.91 per MW-day. The highest APIR for a technology ($386.13 per MW-day) was for subcritical/supercritical coal resources. The maximum APIR effect ($383.79 per MW-day) is the maximum amount by which an offer cap was increased by APIR.

2010/2011 RPM Base Residual Auction

As shown in Table 5-8, 1,104 generating resources submitted offers in the 2010/2011 RPM Auction as compared to 1,093 generating resources offered in the 2009/2010 RPM Auction. Unit-specific offer caps were calculated for 154 resources (13.9 percent) including 134 resources (12.1 percent) with an APIR component and 20 resources (1.8 percent) without an APIR component. Offer caps of all kinds were calculated for 532 resources (48.1 percent), of which 370 (33.5 percent) were based on the technology specific default (proxy) ACR posted by the MMU. There were 15 new generation resources with uncapped offers while the remaining 557 generation resources were price takers, of which the offers for 546 resources were zero and the offers for 11 resources were set to zero because no data were submitted.[25]

Of the 1,104 generating resources which submitted offers, 134 (12.1 percent) included an APIR component. (See Table 5-8.) As shown in Table 5-9, the weighted-averages for resources with APIR for ACR ($360.27 per MW-day) and offer caps ($110.25 per MW-day) were higher than the ACR ($80.86 per MW-day) and offer caps ($20.98 per MW-day) for resources without an APIR component, including resources for which the default value was selected. The APIR component added $272.18 per MW-day to the ACR value of the APIR resources.[26] The default ACR values include an average APIR of $0.91 per MW-day. The highest APIR for a technology ($494.87 per

23 Generally, planned units are not subject to mitigation. The seven other planned units submitted zero price offers. See PJM "Open Access Transmission Tariff (OATT)," "Attachment DD: Reliability Pricing Model," Original Sheet No. 617 (Effective June 1, 2007), section 6.5 (a) ii.

24 Of the 129 units which had an APIR component, 109 units had current year capital dollars submitted of $2.5 billion on 14,519.2 MW UCAP. Twenty units had APIR based on the inclusion of 2007/2008 and 2008/2009 capital projects.

25 Planned units are subject to mitigation only under specific circumstances defined in the tariff. Some of the uncapped planned units submitted zero price offers.

26 The 134 units which had an APIR component submitted $1.5 billion for capital projects associated with 12,645.3 MW UCAP.

MW-day) was for subcritical/supercritical coal resources. The maximum APIR effect ($577.03 per MW-day) is the maximum amount by which an offer cap was increased by APIR.

2011/2012 RPM Base Residual Auction

As shown in Table 5-8, 1,125 generating resources submitted offers in the 2011/2012 RPM Auction as compared to 1,104 generating resources offered in the 2010/2011 RPM Auction. Unit-specific offer caps were calculated for 145 resources (12.9 percent of all generating resources offered) including 133 resources (11.8 percent) with an APIR component and 12 resources (1.1 percent) without an APIR component. Offer caps of all kinds were calculated for 472 resources (42.0 percent), of which 301 (26.8 percent) were based on the technology specific default (proxy) ACR posted by the MMU. There were 20 new generation resources with uncapped offers while the remaining 633 generation resources were price takers, of which the offers for 578 resources were zero and the offers for 55 resources were set to zero because no data were submitted.[27]

Of the 1,125 generating resources which submitted offers, 133 (11.8 percent) included an APIR component. (See Table 5-8.) As shown in Table 5-9, the weighted-averages for resources with APIR for ACR ($424.49 per MW-day) and offer caps ($147.77 per MW-day) were higher than the ACR ($75.86 per MW-day) and offer caps ($45.80 per MW-day) for resources without an APIR component, including resources for which the defaults ACR value was selected. The APIR component added $324.58 per MW-day to the ACR value of the APIR resources.[28] The default ACR values include an average APIR of $0.91 per MW-day. The highest APIR for a technology ($560.20 per MW-day) was for subcritical/supercritical coal resources. The maximum APIR effect ($523.26 per MW-day) is the maximum amount by which an offer cap was increased by APIR.

Market Performance

Prices for capacity increased from $40.80 per MW-day for the RTO for the 2007/2008 BRA to a high of $237.33 per MW-day (SWMAAC) for the 2009/2010 BRA. (See Table 5-10.)

Annual weighted average capacity prices increased from a CCM/RPM combined, weighted average price of $5.73 per MW-day in 2006 to an RPM weighted-average price of $173.15 per MW-day in 2010 and then declined to $136.62 per MW-day in 2011. Figure 5-1 presents capacity market prices on a calendar year basis for the entire history of the PJM capacity markets.

As Table 5-5 shows, net excess decreased 229.42 MW from 5,240.5 MW on June 1, 2007, to 5,011.1 MW on June 1, 2008, because of a 2,657.3 MW increase in the RPM reliability requirement from 148,277.3 MW to 150,934.6 MW.[29] This increase was caused by a higher peak-load forecast and was partially offset by an increase of 1,513.5 MW in unforced capacity from 154,076.7 MW on June 1, 2007, to 155,590.2 MW on June 1, 2008.[30] The increase in unforced capacity was the result

27 Planned units are subject to mitigation only under specific circumstances defined in the tariff. Some of the 20 uncapped planned units submitted zero price offers.

28 The 133 units which had an APIR component submitted $613.8 million for capital projects associated with 8,813.7 MW UCAP.

29 Net excess under RPM is calculated as cleared capacity less the reliability requirement plus ILR. For 2007/2008 and 2008/2009, certified ILR was used in the calculation. For 2009/2010 and 2010/2011, forecast ILR less FRR DR is used in the calculation because PJM forecast ILR including FRR DR for the first four base residual auctions. FRR DR is not subtracted in the calculation for the 2011/2012 auction because PJM forecast ILR excluding FRR DR for the 2011/2012 BRA. Net excess calculations for auctions prior to 2010/2011 were originally calculated as cleared capacity less the reliability requirement.

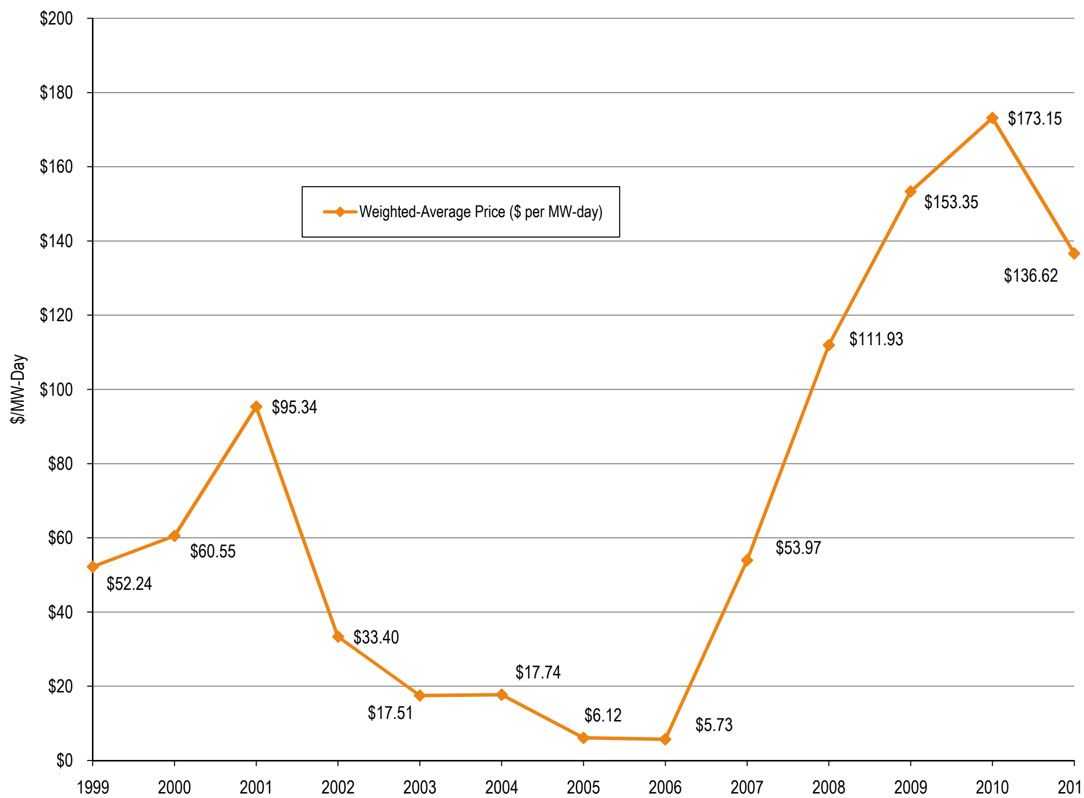
30 Unforced capacity is defined as the UCAP value of iron in the ground plus the UCAP value of imports less the UCAP value of exports.

of a decrease in exports of 100.4 MW plus a 1,762 MW growth in total internal capacity (Table 5-1), both of which were partially offset by a decrease in imports of 348.9 MW.

Table 5-10 Capacity prices: 2007/2008 through 2011/2012 RPM Auctions

	RPM Clearing Price ($ per MW-day)				
	RTO	EMAAC	SWMAAC	MAAC+APS	DPL-South
2007/2008 BRA	$40.80	$197.67	$188.54		
2008/2009 BRA	$111.92	$148.80	$210.11		
2008/2009 Third IA	$10.00		$223.85		
2009/2010 BRA	$102.04		$237.33	$191.32	
2010/2011 BRA	$174.29				$178.27
2011/2012 BRA	$110.00				

Figure 5-1 History of capacity prices: Calendar year 1999 through 2011[31,32]



31 1999-2006 capacity prices are CCM combined market, weighted average prices. The 2007 capacity price is a combined CCM/RPM weighted average price. The 2008-2011 capacity prices are RPM weighted average prices.

32 The calculation of the 2007 weighted average price has been revised since the value in the *2007 State of the Market Report* was posted.

Table 5-11 RPM cost to load: 2008/2009 through 2011/2012 RPM Auctions[33,34,35]

	Net Load Price ($/MW-Day)	UCAP Obligation (MW)	Annual Charges
2008/2009 BRA			
RTO	$113.22	79,814.6	$3,298,362,289
EMAAC	$145.24	35,755.4	$1,895,486,718
SWMAAC	$183.03	15,684.6	$1,047,824,603
2009/2010 BRA			
RTO	$102.04	57,520.9	$2,142,342,912
MAAC+APS	$188.55	60,399.9	$4,156,766,418
SWMAAC	$218.12	15,966.1	$1,271,121,892
2010/2011 BRA			
RTO	$174.29	129,253.2	$8,222,552,183
DPL	$178.27	4,595.0	$298,989,987
2011/2012 BRA			
RTO	$110.04	133,815.3	$5,389,363,034

Table 5-11 shows the RPM annual charges to load. For the 2008/2009 planning year, annual charges totaled approximately $6.2 billion.

2008/2009 RPM Base Residual Auction

Cleared capacity resources across the entire RTO will receive a total of $6.1 billion based on the unforced MW cleared and the prices in the 2008/2009 BRA.

RTO

Table 5-12 shows total RTO offer data for the 2008/2009 RPM Auction, which includes the EMAAC and SWMAAC LDAs. Total internal RTO unforced capacity of 156,968.0 MW includes all generating units and DR that qualified as a PJM capacity resource for the 2008/2009 RPM Auction, excluding external units, and also includes owners' modifications to installed capacity ratings which are permitted under the PJM Reliability Assurance Agreement (RAA) and associated manuals.[36]

33 The annual charges are calculated using the rounded, net load prices as posted in the PJM Base Residual Auction results.
34 There is no separate obligation for DPL-South as the DPL-South LDA is completely contained within the DPL Zone.
35 The Final UCAP Obligation is determined after the clearing of the second incremental auction. If a second incremental auction is not held, the final UCAP Obligation is equal to the Base UCAP Obligation. The Final Zonal Capacity Prices are determined after certification of ILR. The 2009/2010, 2010/2010 and 2011/2012 Net Load Prices are not finalized. The 2010/2011 and 2011/2012 Obligation MW are not finalized.
36 See "Reliability Assurance Agreement among Load-Serving Entities in the PJM Region" (June 1, 2007) (Accessed February 3, 2009) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/raa.ashx> (1.92 MB).

After accounting for FRR committed resources and for imports, RPM capacity was 136,237.3 MW.[37] This amount was reduced by exports of 3,838.1 MW[38] and 188.5 MW which were excused from the RPM must-offer requirement as a result of environmental regulations (151.0 MW), generation moving behind the meter (17.3 MW), non-utility generator (NUG) ownership questions (17.7 MW) and other factors (2.5 MW). Subtracting 330.1 MW of FRR optional volumes not offered, resulted in 131,880.6 MW that were available to be offered into the auction.[39] Offered volumes included 1,711.1 MW of EFORd offer segments. All capacity resources were offered into the RPM Auction. Four new wind resources (60.9 MW), three new diesel resources (23.3 MW) and two resources (112.6 MW) which came out of retirement were offered into the auction.

The downward sloping demand curve resulted in more capacity cleared in the market than the reliability requirement. The 129,597.6 unforced MW of cleared resources for the entire RTO represented a reserve margin of 17.5 percent, which was 1,403.0 MW greater than the reliability requirement of 128,194.6 MW (IRM of 15.0 percent).[40,41,42] As shown in Figure 5-2, the downward sloping demand curve resulted in a price of $111.92 per MW-day. Net excess was 5,011.1 MW, which was a decrease of 229.4 MW from the net excess of 5,240.5 MW in the 2007/2008 RPM Auction. (See Table 5-5.) This decrease was mainly because of an increase in the RTO load forecast of 2,385.0 MW from 137,421.0 MW to 139,806.0 MW effective June 1, 2008. Certified ILR was 3,608.1 MW.

As shown in Table 5-12, the net load price that LSEs will pay is $113.22 per MW-day in the RTO area not included in the constrained LDAs. This value is the final zonal capacity price. The final zonal capacity price is the resource-clearing price adjusted for differences between the certified ILR for the delivery year and the forecasted RTO ILR obligation.

37 The FRR alternative allows an LSE, subject to certain conditions, to avoid direct participation in the RPM Auctions. The LSE is required to submit an FRR capacity plan to satisfy the unforced capacity obligation for all load in its service area.

38 If all of the exports had been offered into the auction at $0.00 per MW-day, the clearing price would have been approximately $56.00 per MW-day.

39 FRR entities are allowed to offer into the RPM Auction excess volumes above their FRR quantities, subject to a sales' cap amount. The 330.1 MW are excess volumes included in the sales' cap amount which were not offered into the auction.

40 Both the reserve margin calculation and IRM include FRR resources and FRR load and are on an ICAP basis.

41 The RTO reliability requirement, which is after FRR adjustments, is plotted on the variable resource requirement (VRR) curve as the reliability requirement less the ILR forecast obligation plus any FRR DR.

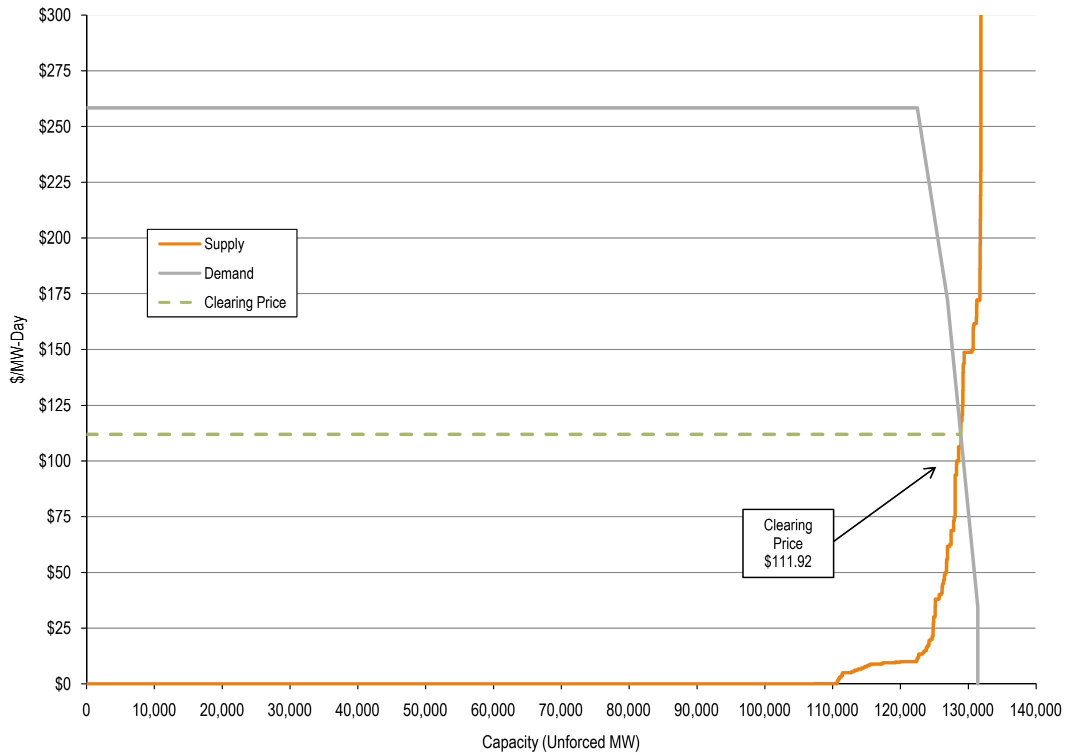
42 The demand curve UCAP quantities are based on three points, which are ratios of the installed reserve margin (IRM =15.0 percent) times the reliability requirement, less the forecast RTO ILR obligation. For the three points, the ratios are 1.12/1.15, 1.16/1.15 and 1.20/1.15. For these three points the UCAP prices are based on factors multiplied by net cost of net entry (CONE) divided by one minus the pool-wide EFORd. Net CONE is defined as CONE minus the energy and ancillary service revenue offset (E&AS). For the three points, the factors are 1.5, 1.0 and 0.2. For 2008/2009, CONE was $197.83 per MW-day and E&AS was $36.12 MW-day.

Table 5-12 RTO offer statistics: 2008/2009 RPM Base Residual Auction[43]

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Total Internal RTO Capacity (Gen and DR)	166,037.9	156,968.0		
FRR	(24,953.5)	(23,191.0)		
Imports	2,612.0	2,460.3		
RPM Capacity	143,696.4	136,237.3		
Exports	(4,205.8)	(3,838.1)		
FRR Optional	(356.7)	(330.1)		
Excused	(365.3)	(188.5)		
Available	138,768.6	131,880.6	100.0%	100.0%
Generation Offered	138,076.7	131,164.8	99.5%	99.5%
DR Offered	691.9	715.8	0.5%	0.5%
Total Offered	138,768.6	131,880.6	100.0%	100.0%
Unoffered	0.0	0.0	0.0%	0.0%
Cleared in RTO	135,613.1	128,910.6	97.8%	97.8%
Cleared in LDAs	743.6	687.0	0.5%	0.5%
Total Cleared	136,356.7	129,597.6	98.3%	98.3%
Uncleared in RTO	1,185.1	1,130.0	0.8%	0.8%
Uncleared in LDAs	1,226.8	1,153.0	0.9%	0.9%
Total Uncleared	2,411.9	2,283.0	1.7%	1.7%
Reliability Requirement		128,194.6		
Total Cleared		129,597.6		
ILR Certified		3,608.1		
RPM Net Excess/(Deficit)		5,011.1		
Resource Clearing Price ($ per MW-day)		$111.92	A	
Final Zonal Capacity Price ($ per MW-day)		$113.22	B	
Final Zonal CTR Credit Rate ($ per MW-day)		$0.00	C	
Final Zonal ILR Price ($ per MW-day)		$111.92	A-C	
Net Load Price ($ per MW-day)		$113.22	B-C	

43 Prices are only for those generating units outside of EMAAC and SWMAAC.

Figure 5-2 RTO market supply/demand curves: 2008/2009 RPM Base Residual Auction[44,45]



EMAAC

Table 5-13 shows total EMAAC offer data for the 2008/2009 RPM Auction. Total internal EMAAC unforced capacity of 31,396.7 MW includes all generating units and DR that qualified as a PJM capacity resource, excluding external units, and also includes owners' modifications to ICAP ratings. Including imports of 17.6 MW into EMAAC, RPM unforced capacity was 31,396.7 MW. This amount was reduced by 17.3 MW which were excused from the RPM must-offer requirement as a result of generation moving behind the meter, resulting in 31,379.4 MW that were available to be offered into the auction. All capacity resources were offered into the RPM Auction.

Of the 30,231.3 MW cleared in EMAAC, 28,829.9 MW were cleared in the RTO before EMAAC became constrained. Once the constraint was binding, based on the 7,930.0 MW CETL value, only the incremental supply located in EMAAC was available to meet the incremental demand in the LDA. Of the 1,549.5 MW of incremental supply, 401.4 MW cleared, which resulted in a resource-clearing price of $148.80 per MW-day, as shown in Figure 5-3. The price was determined by the intersection of the incremental supply and demand curves. The uncleared MW were the result of offer prices which exceeded the demand curve.

44 The supply curve includes all supply offers at the lower of offer price or offer cap. The demand curve excludes incremental demand which cleared in EMAAC and SWMAAC.

45 For ease of viewing, the graph was truncated at $300.00 per MW-day and does not show an uncleared offer of approximately $800.00 per MW-day.

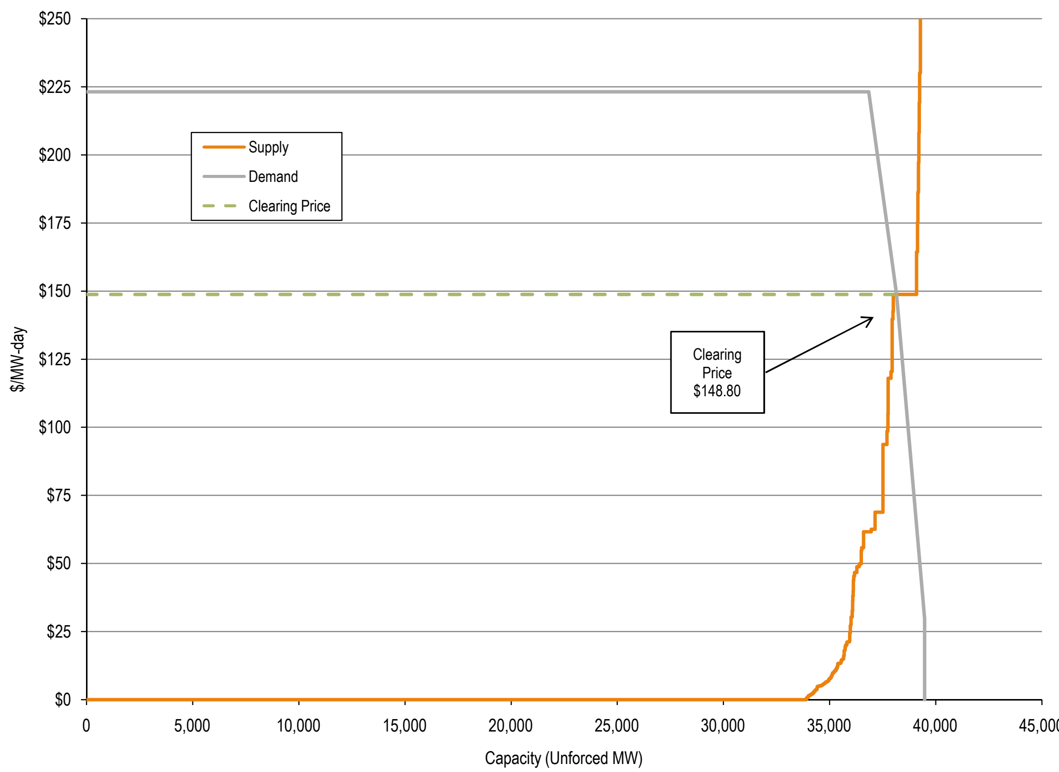
Total resources in EMAAC were 38,161.3 MW, which when combined with certified ILR of 622.6 MW resulted in a net excess of 893.2 MW (2.3 percent) greater than the reliability requirement of 37,890.7 MW.

As shown in Table 5-13, the net load price that LSEs will pay is $145.24 per MW-day. This value is the final zonal capacity price ($150.53 per MW-day) less the final CTR credit rate ($5.29 per MW-day). The CTR MW value allocated to load in an LDA is the LDA UCAP obligation less the cleared generation internal to the LDA less the ILR forecast for the LDA. This MW value is multiplied by the locational price adder for the LDA to arrive at the economic value of the CTRs allocated to the load in the LDA. This value is then divided by the LDA UCAP obligation to arrive at the final CTR credit rate for the LDA. The final CTR credit rate is an allocation of the economic value of transmission import capability that exists in constrained LDAs and serves to offset a portion of the locational price adder charged to load in constrained LDAs.

Table 5-13 EMAAC offer statistics: 2008/2009 RPM Base Residual Auction

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Total Internal EMAAC Capacity (Gen and DR)	33,472.8	31,379.1		
Imports	17.6	17.6		
RPM Capacity	33,490.4	31,396.7		
Exports	0.0	0.0		
Excused	(18.1)	(17.3)		
Available	33,472.3	31,379.4	100.0%	100.0%
Generation Offered	33,140.3	31,036.0	99.0%	98.9%
DR Offered	332.0	343.4	1.0%	1.1%
Total Offered	33,472.3	31,379.4	100.0%	100.0%
Unoffered	0.0	0.0	0.0%	0.0%
Cleared in RTO	31,797.7	29,829.9	94.9%	95.0%
Cleared in LDA	452.5	401.4	1.4%	1.3%
Total Cleared	32,250.2	30,231.3	96.3%	96.3%
Uncleared	1,222.1	1,148.1	3.7%	3.7%
Reliability Requirement		37,890.7		
Total Cleared		30,231.3		
CETL		7,930.0		
Total Resources		38,161.3		
ILR Certified		622.6		
RPM Net Excess/(Deficit)		893.2		
Resource Clearing Price ($ per MW-day)		$148.80	A	
Final Zonal Capacity Price ($ per MW-day)		$150.53	B	
Final Zonal CTR Credit Rate ($ per MW-day)		$5.29	C	
Final Zonal ILR Price ($ per MW-day)		$143.51	A-C	
Net Load Price ($ per MW-day)		$145.24	B-C	

Figure 5-3 EMAAC supply/demand curves: 2008/2009 RPM Base Residual Auction[46]



SWMAAC

Table 5-14 shows total SWMAAC offer data for the 2008/2009 RPM Auction. Total internal SWMAAC unforced capacity of 10,777.1 MW includes all generating units and DR that qualified as a PJM capacity resource, excluding external units, and also includes owners' modifications to ICAP ratings. Since there were no imports from outside PJM into SWMAAC, RPM unforced capacity was 10,777.1 MW. This amount was reduced by 151.0 MW which were excused from the RPM must-offer requirement as a result of environmental regulations, resulting in 10,626.1 MW that were available to be offered into the auction. All capacity resources were offered into the RPM Auction.

Of the 10,621.2 MW cleared in SWMAAC, 10,335.6 MW had cleared in the RTO before SWMAAC became constrained. Once the constraint was binding, based on the 5,610.0 CETL value, only the incremental supply in SWMAAC was available to meet incremental demand in the LDA. Of the 290.5 MW of incremental supply, 285.6 MW cleared, which resulted in a resource clearing price of $210.11 per MW-day. (See Figure 5-4.)

Total resources in SWMAAC were 16,231.2 MW, which when combined with certified ILR of 219.7 MW resulted in a net deficit of 111.0 MW (.7 percent) less than the reliability requirement of 16,561.9 MW.

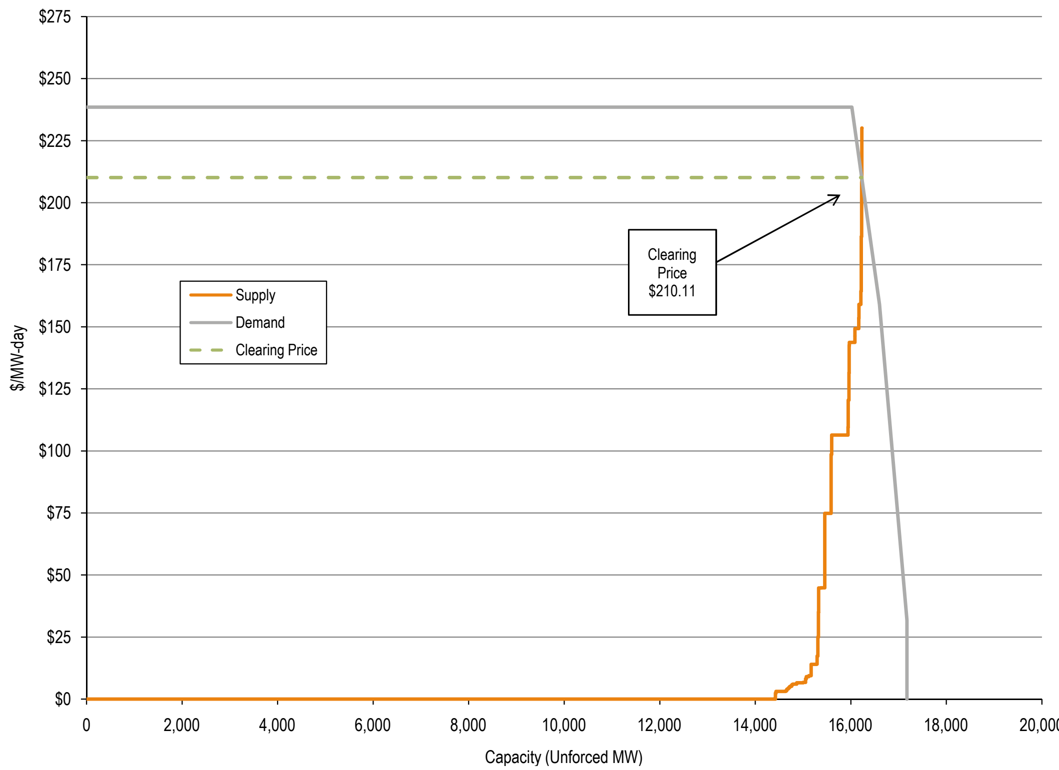
46 The supply curve was truncated at $250.00 per MW-day and does not show an uncleared offer of approximately $800.00 per MW-day.

As shown in Table 5-14, the net load price that LSEs will pay is $183.03 per MW-day. This value is the final zonal capacity price ($212.56 per MW-day) less the final CTR credit rate ($29.53 per MW-day).

Table 5-14 SWMAAC offer statistics: 2008/2009 RPM Base Residual Auction

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Total Internal SWMAAC Capacity (Gen and DR)	11,868.6	10,777.1		
Imports	0.0	0.0		
RPM Capacity	11,868.6	10,777.1		
Exports	0.0	0.0		
Excused	(316.0)	(151.0)		
Available	11,552.6	10,626.1	100.0%	100.0%
Generation Offered	11,249.1	10,312.0	97.4%	97.0%
DR Offered	303.5	314.1	2.6%	3.0%
Total Offered	11,552.6	10,626.1	100.0%	100.0%
Unoffered	0.0	0.0	0.0%	0.0%
Cleared in RTO	11,256.8	10,335.6	97.5%	97.3%
Cleared in LDA	291.1	285.6	2.5%	2.7%
Total Cleared	11,547.9	10,621.2	100.0%	100.0%
Uncleared	4.7	4.9	0.0%	0.0%
Reliability Requirement		16,561.9		
Total Cleared		10,621.2		
CETL		5,610.0		
Total Resources		16,231.2		
ILR Certified		219.7		
RPM Net Excess/(Deficit)		(111.0)		
Resource Clearing Price ($ per MW-day)		$210.11	A	
Final Zonal Capacity Price ($ per MW-day)		$212.56	B	
Final Zonal CTR Credit Rate ($ per MW-day)		$29.53	C	
Final Zonal ILR Price ($ per MW-day)		$180.58	A-C	
Final Net Load Price ($ per MW-day)		$183.03	B-C	

Figure 5-4 SWMAAC supply/demand curves: 2008/2009 RPM Base Residual Auction



2008/2009 RPM Third Incremental Auction

Under RPM, the Third Incremental Auction, which is held in January prior to the start of the delivery year, allows capacity resource owners to buy and sell capacity to accommodate adjustments to participants' resource positions as a result of resource retirements, cancellations, delays or changes in a resource's EFORd. The demand curve in the Third Incremental Auction is entirely a function of demand bids. There is no administrative market demand curve.

Cleared resources across the entire RTO will receive a total of $5.4 million based on the unforced MW cleared and the prices in the 2008/2009 RPM Third Incremental Auction.

RTO

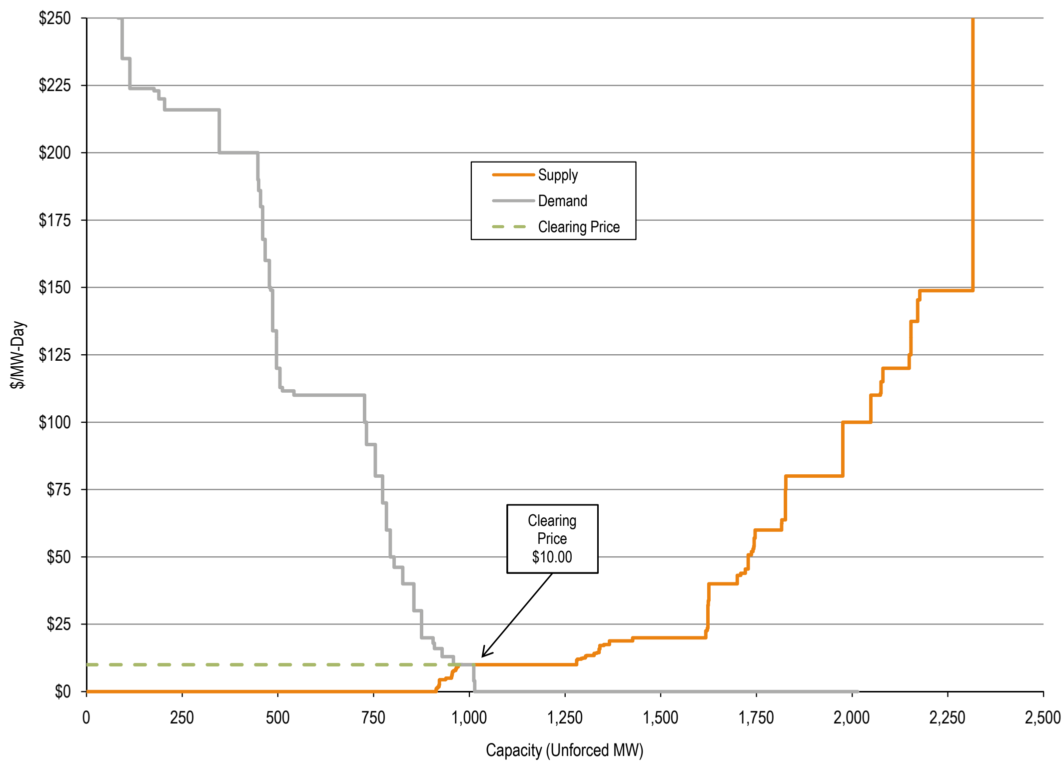
Table 5-15 shows total RTO offer and bid data for the 2008/2009 RPM Third Incremental Auction. There were 2,339.4 MW offered into the incremental auction while buy bids totaled 2,251.8 MW. The offered volumes came from uncleared offers from the 2008/2009 BRA (2,283.0 MW), three new resources (64.6 MW), four reactivated resources (166.9 MW), nine new DR resources (22.8 MW), net derates to existing DR resources (-179.2 MW), net derates to existing generating resources (-171.7 MW) and higher UCAP values due to improved EFORds (153.0 MW). Of the 904.3 MW with zero price offers, 872.2 MW had zero price offer caps. Buy bids were submitted to cover short positions due to deratings and EFORd increases or because participants wished to purchase additional capacity. No EFORd offer segments were permitted in this auction because the delivery year EFORds were known for this auction and the EFORd risk was therefore zero. Cleared volumes in the RTO were 1,011.6 MW, resulting in an RTO clearing price of $10.00 per MW-day (See Figure 5-5.) The price was set by the transition adder. The RTO clearing price in the 2008/2009 BRA was $111.92 per MW-day. The 1,307.2 MW of uncleared volumes can be used as replacement volumes or traded bilaterally.

Although EMAAC was constrained in the 2008/2009 BRA, supply offers in the incremental auction in EMAAC (1,142.8 MW) exceeded EMAAC demand bids (191.0 MW). The offered volumes came from uncleared offers from the 2008/2009 BRA (1,148.1 MW), one new resource (5.2 MW), three reactivated resources (9.7 MW), net derates to existing DR resources (-174.4 MW), net uprates to existing resources (66.5 MW) and higher UCAP values due to improved EFORds (87.7 MW). Supply and demand resulted in a price less than the RTO clearing price. The result was that all of EMAAC supply which cleared received the RTO clearing price.

Table 5-15 RTO offer statistics: 2008/2009 RPM Third Incremental Auction

	Offered (Supply)		Bid (Demand)
	ICAP (MW)	UCAP (MW)	UCAP (MW)
Generation	2,468.3	2,316.2	
DR	22.6	23.2	
Total	2,490.9	2,339.4	2,251.8
Cleared in RTO	1,046.4	1,011.6	1,011.6
Cleared in SWMAAC	0.0	0.0	0.0
Total cleared	1,046.4	1,011.6	1,011.6
Uncleared in RTO	1,444.5	1,327.8	1,240.2
Uncleared in SWMAAC	0.0	0.0	0.0
Total uncleared	1,444.5	1,327.8	1,240.2
Resource clearing price ($ per MW-day)	$10.00		

Figure 5-5 RTO supply/demand curves: 2008/2009 RPM Third Incremental Auction



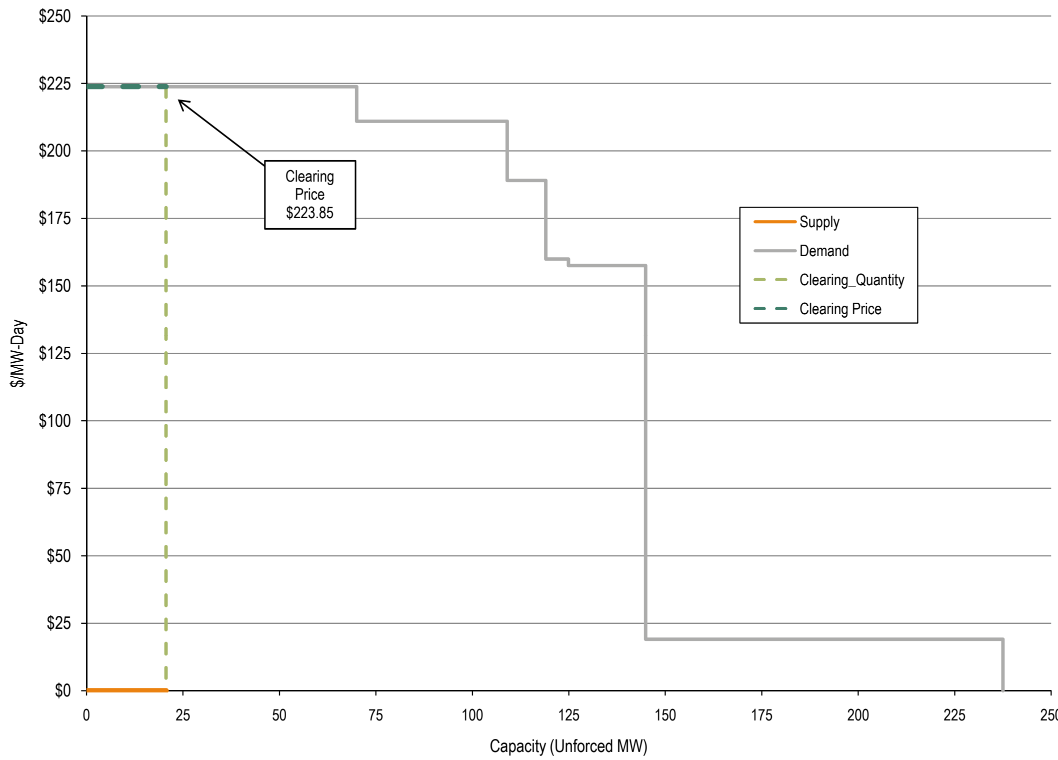
SWMAAC

Table 5-16 shows total SWMAAC offer and bid data for the 2008/2009 RPM Third Incremental Auction. There were 20.6 MW in SWMAAC offered into the auction while buy bids in SWMAAC totaled 237.5 MW. Except for 0.1 MW of new DR, the offered volumes came from capacity modifications (14.6 MW) and higher UCAP values due to improved EFORds (5.9 MW). SWMAAC was a constrained LDA for the 2008/2009 delivery year, so the only supply which could meet the demand was the 20.6 MW in SWMAAC. Since these offered volumes were less than buy bids, the price was set by a vertical extension of the supply curve to meet demand, resulting in a clearing price of $223.85 per MW-day. (See Figure 5-6.) The SWMAAC clearing price in the 2008/2009 BRA was $210.11 per MW-day.

Table 5-16 SWMAAC offer statistics: 2008/2009 RPM Third Incremental Auction

	Offered (Supply)		Bid (Demand)
	ICAP (MW)	UCAP (MW)	UCAP (MW)
Generation	22.9	20.5	
DR	0.1	0.1	
Total	23.0	20.6	237.5
Cleared in RTO	0.0	0.0	0.0
Cleared in SWMAAC	23.0	20.6	20.6
Total cleared	23.0	20.6	20.6
Uncleared	0.0	0.0	216.9
Resource clearing price ($ per MW-day)	$223.85		

Figure 5-6 SWMAAC supply/demand curves: 2008/2009 RPM Third Incremental Auction



Generator Performance

Generator performance results from the interaction between the physical nature of the units and the level of expenditures made to maintain the capability of the units, which in turn is a function of incentives from energy, ancillary services and capacity markets. Generator performance can be measured using indices calculated from historical data. Generator performance indices include those based on total hours in a period (generator performance factors) and those based on hours when units are needed to operate by the system operator (generator forced outage rates).[47]

Generator Performance Factors

Generator performance factors are based on a defined period, usually a year, and are directly comparable.[48] Performance factors include the equivalent availability factor (EAF), the equivalent maintenance outage factor (EMOF), the equivalent planned outage factor (EPOF) and the equivalent forced outage factor (EFOF). These four factors add to 100 percent for any generating unit. The EAF is the proportion of hours in a year when a unit is available to generate at full capacity while the three outage factors include all the hours when a unit is unavailable. The EMOF is the proportion of hours in a year when a unit is unavailable because of maintenance outages and maintenance deratings. The EPOF is the proportion of hours in a year when a unit is unavailable because of planned outages and planned deratings. The EFOF is the proportion of hours in a year when a unit is unavailable because of forced outages and forced deratings.

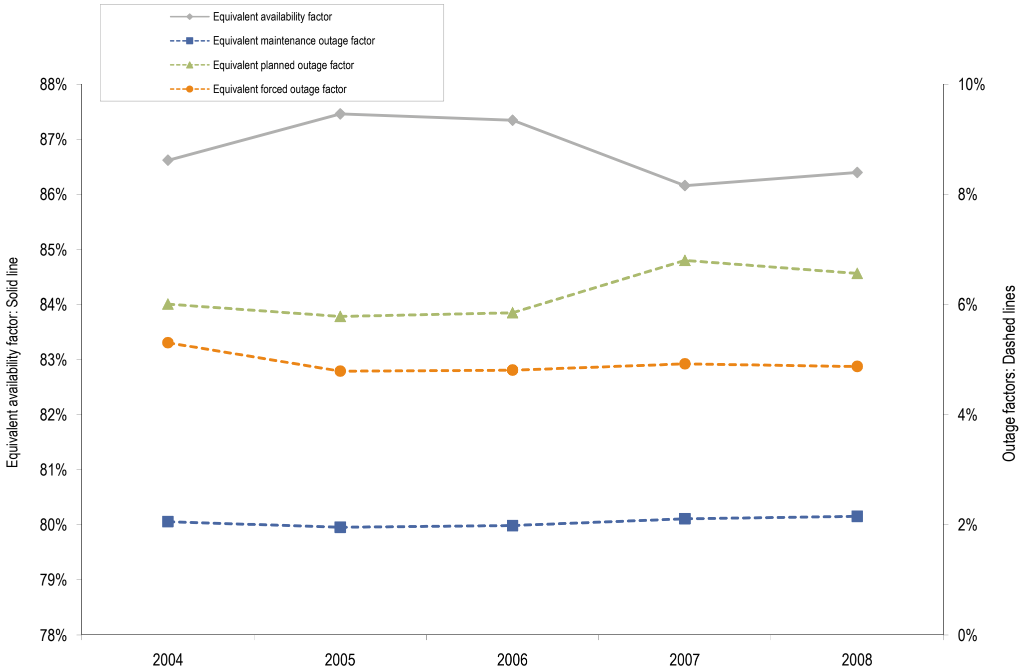
The PJM aggregate EAF increased from 86.2 percent in 2007 to 86.4 percent in 2008. The EFOF decreased 0.047 percentage points from 2007, to 4.877 percent while the EPOF decreased by about 0.237 percentage points to 6.567 and the EMOF increased 0.045 percentage points to 2.155.[49] (See Figure 5-7.)

47 The generator performance analysis includes all PJM capacity resources for which there are data in the PJM GADS database. This set of capacity resources may include generators in addition to those in the set of generators committed as resources in the RPM.

48 Data from all PJM capacity resources for the years 2004 through 2008 were analyzed.

49 The performance factor data include all units from PJM. Results for prior years may be different from previous reports as corrections can be made at any time with permission from the PJM GADS administrators. Data are for 12 months ended December 31, 2008, as downloaded from the PJM GADS database on January 23, 2009.

Figure 5-7 PJM equivalent outage and availability factors: Calendar years 2004 to 2008



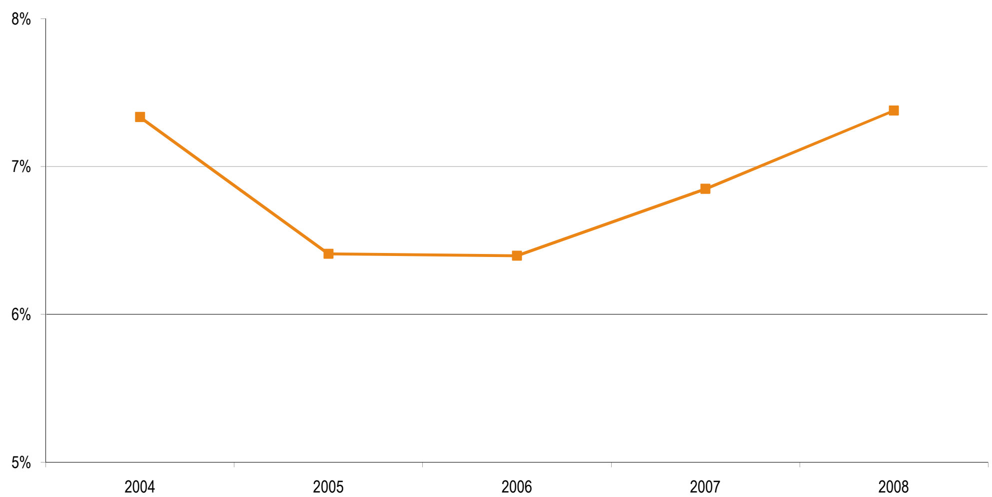
Generator Forced Outage Rates

The equivalent demand forced outage rate (EFORd) (generally referred to as the forced outage rate) is a measure of the probability that a generating unit will fail, either partially or totally, to perform when it is needed to operate. EFORd is calculated using historical performance data. PJM systemwide EFORd is a capacity-weighted average of individual unit EFORd. Unforced capacity for any individual generating unit is equal to one minus the EFORd multiplied by the unit's net dependable summer capability. The PJM Capacity Market creates an incentive to minimize the forced outage rate because the amount of capacity resources available to sell from a unit (unforced capacity) is inversely related to the forced outage rate.

EFORd calculations use historical data, including equivalent forced outage hours,[50] service hours, average forced outage duration, average run time, average time between unit starts, available hours and period hours.[51] The average PJM EFORd decreased from 7.3 percent in 2005 to 6.4 percent in 2005 and 2006 and increased to 6.8 percent in 2007 and 7.4 percent in 2008.[3] The increase in EFORd from 2007 to 2008 was the result of increased forced outage rates for steam and nuclear generating units. Figure 5-8 shows the average EFORd since 2004 for all units in PJM.

50 Equivalent forced outage hours are the sum of all forced outage hours in which a generating unit is fully inoperable and all partial forced outage hours in which a generating unit is partially inoperable prorated to represent full hours.
51 See PJM. "Manual 22: Generator Resource Performance Indices," Revision 15 (June 1, 2007), Equations 2 through 5.

Figure 5-8 Trends in the PJM equivalent demand forced outage rate (EFORd): Calendar years 2004 to 2008



Components of Change in EFORd

Table 5-17 shows the contribution of each unit type to the system EFORd, calculated as the total forced MW for the unit type divided by the total capacity of the system.[52] Forced MW for a unit type is the EFORd multiplied by the generator's net dependable summer capability.

Table 5-17 Contribution to EFORd for specific unit types (Percentage points): Calendar years 2004 to 2008[53]

	2004	2005	2006	2007	2008	Change in 2008 from 2007
Combined cycle	0.5	0.6	0.5	0.4	0.4	0.0
Combustion turbine	1.3	1.3	1.4	1.6	1.5	(0.1)
Diesel	0.0	0.0	0.0	0.0	0.0	0.0
Hydroelectric	0.2	0.1	0.1	0.1	0.1	0.0
Nuclear	0.6	0.3	0.3	0.2	0.4	0.2
Steam	4.7	4.1	4.1	4.4	4.9	0.5
Total	7.3	6.4	6.4	6.8	7.4	0.6

The increase in overall PJM EFORd of 0.6 percentage points (a 7.7 percent increase) between 2007 and 2008 resulted from poorer performance of steam and nuclear units (313 and 32 generating units respectively) which accounted for 0.5 and 0.2 percentage points of the overall increase, or 117%, while improved performance of combustion turbines offset the increase by -0.1 percentage points.

52 The generating unit types are: steam, nuclear, diesel, combustion turbine, combined-cycle and hydroelectric. For all tables, run of river and pumped storage hydroelectric are combined into a single hydroelectric category.

53 Calculated values presented in Section 5, "Capacity Market" at "Generator Performance" are based on unrounded, underlying data and may differ from those derived from the rounded values shown in the tables.

Of the 1,189 generating units in the EFORd analysis during calendar year 2008, 431 units had decreased EFORds, 387 units had increased EFORds and the remaining 371 units had unchanged EFORds.[54] If the 431 units with lower forced outage rates had not experienced rates lower than the average, the 2008 EFORd would have been 9.7 percent, 31 percent higher than the actual overall EFORd of 7.4.

Changes in outage rates by unit type and changes in capacity by unit type combined to produce the observed impacts on system EFORd. Since total capability from fossil steam units remained relatively constant from year to year, the increased forced outage rates for this unit type was the reason for its contribution to the increased system EFORd.

Table 5-18 shows the relative contributions of EFORd and capacity to EFORd levels by unit type and for the system. The contribution of steam units to the increased system EFORd was the result of increased steam unit EFORd (112.0 percent of the steam contribution) which was offset by lower capacity levels for steam units (-12.0 percent). The contribution of nuclear units to the increased system EFORd was the result of increased nuclear unit EFORd (95.8 percent of the nuclear contribution) and of increased capacity levels for nuclear units (4.2 percent). Overall, 117.2 percent of the increase in EFORd from 2007 to 2008 was the result of increased EFORd for nuclear and steam units types, offset by decreased EFORd for combustion turbines and changes in the mix of capacity by unit type.

Table 5-18 Percent change in contribution to EFORd (Unit type): 2008 compared to 2007

	Contribution Change Due to Capacity	Contribution Change Due to EFORd
Combined cycle	31.9%	68.1%
Combustion turbine	42.5%	57.5%
Diesel	14.2%	85.8%
Hydroelectric	(24.6%)	124.6%
Nuclear	4.2%	95.8%
Steam	(12.0%)	112.0%
All unit types	(17.2%)	117.2%

54 A single unit may include more than one set of generator terminals aggregated as a single generator.

Table 5-19 compares 2008 PJM EFORd data by unit type to the five-year North American Electric Reliability Council (NERC) average EFORd data for corresponding unit types. The 2008 PJM forced outage rates for combined cycle, hydroelectric and nuclear units were below the NERC five-year averages. The 2008 PJM EFORd for combustion turbine, diesel and fossil steam units exceeded the NERC averages.[55]

Table 5-19 Five-year PJM EFORd data comparison to NERC five-year average for different unit types: Calendar years 2004 to 2008

	PJM EFORd					NERC EFORd
	2004	2005	2006	2007	2008	2003 to 2007 Average
Combined cycle	5.2%	5.0%	4.3%	3.5%	3.4%	0.0%
Combustion turbine	9.0%	8.9%	9.4%	11.1%	10.9%	8.9%/8.3%
Diesel	8.9%	14.0%	13.2%	11.8%	9.6%	0.0%
Hydroelectric	3.9%	2.5%	1.9%	2.3%	2.4%	0.0%
Nuclear	3.2%	1.6%	1.4%	1.3%	1.9%	0.0%
Steam	9.2%	8.1%	8.2%	8.8%	9.8%	0.0%
Overall	7.3%	6.4%	6.4%	6.8%	7.4%	NA

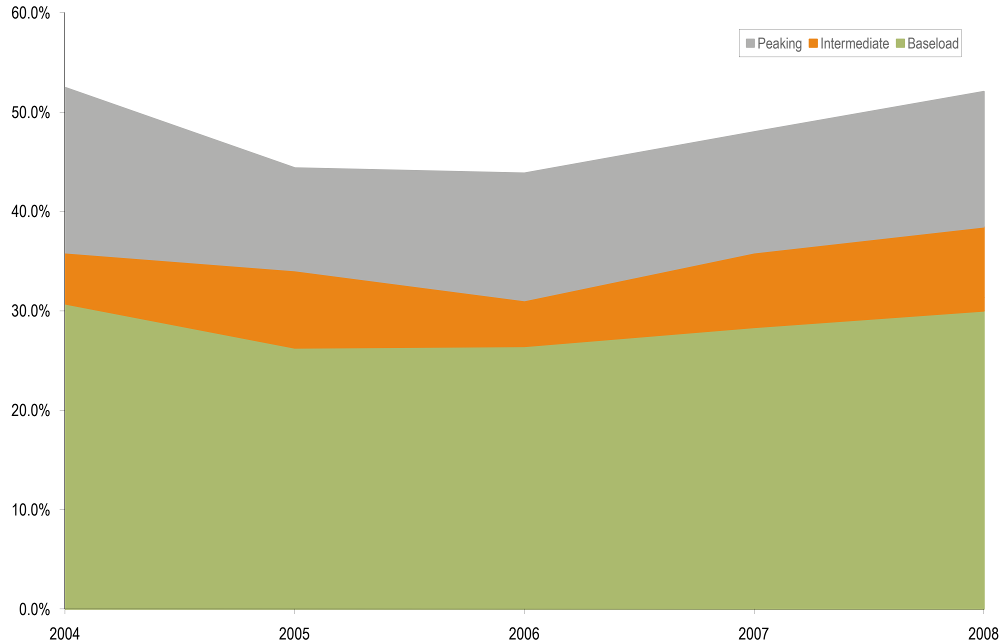
Duty Cycle and EFORd

In addition to disaggregating system EFORd by unit type, units were categorized by actual duty cycles as baseload, intermediate or peaking to determine the relationship between type of operation and forced outage rates.[56] Figure 5-9 shows the contribution of unit types to system average EFORd. In 2008, of 21,323 total MW of combined-cycle units, approximately 6,497 MW are in baseload classes, 11,555 MW in the intermediate, and 3,271 MW are in peaking classes. Of the 24,157 total MW of combustion turbine units, approximately 533 MW are in baseload classes, 1,589 MW in the intermediate, and 22,036 MW are in peaking classes.

55 NERC defines combustion turbines in two categories: jet engines and gas turbines. Their EFORd for the 2003 to 2007 period are 8.9 percent and 8.3 percent, respectively, per NERC's GADS "2003-2007 Generating Unit Statistical Brochure - Units Reporting Events" <http://www.nerc.com/files/2003-2007%20Generating%20Unit%20Statistical%20Brochure%20-%20Units%20Reporting%20Events.zip> (32 KB). Also, the NERC average for fossil steam units is a unit-year-weighted value for all units reporting. The PJM values are weighted by capability for each calendar year.

56 Duty cycle is the time the unit is generating divided by the time the unit is available to generate. A baseload unit is defined as a unit that generates during 50 percent or more of its available hours. An intermediate unit is defined as a unit that generates during from 10 percent to 50 percent of its available hours. A peaking unit is defined as a unit that generates during less than 10 percent of its available hours. These terms were defined for the purposes of this analysis.

Figure 5-9 Contribution to EFORd by duty cycle: Calendar years 2004 to 2008



Forced Outage Analysis

The MMU analyzed the causes of forced outages for the entire PJM system. The metric used was lost generation, which is the product of the duration of the outage and the size of the outage reduction. Lost generation can be converted into lost system equivalent availability.[57] On a systemwide basis, the resultant lost equivalent availability from the forced outages is equal to the equivalent forced outage factor.

The PJM EAF for 2008 was 86.4 percent; the corresponding EMOF and EPOF were 2.2 percent and 6.6 percent, respectively. As a result, the 2008 PJM EFOF was 4.9 percent. This means 4.9 percent lost availability because of forced outages.

The major reasons for this lost equivalent availability are listed in Table 5-20.

57 For any unit, lost generation can be converted to lost equivalent availability by dividing lost generation by the product of the generating units' capacity and period hours. This can also be done on a systemwide basis.

Table 5-20 Outage cause contribution to PJM EFOF: Calendar year 2008

	Percentage Point Contribution to EFOF	Contribution to EFOF
Boiler Tube Leaks	0.96	19.7%
Economic	0.60	12.4%
Low Pressure Turbine	0.29	6.0%
Boiler Air and Gas Systems	0.23	4.8%
Boiler Fuel Supply from Bunkers to Boiler	0.21	4.4%
Feedwater System	0.16	3.3%
Miscellaneous (Generator)	0.16	3.2%
Stack Emission	0.15	3.0%
Fuel Quality	0.13	2.7%
Circulating Water Systems	0.12	2.4%
Electrical	0.12	2.4%
Miscellaneous (Steam Turbine)	0.08	1.7%
Performance	0.08	1.7%
Miscellaneous (Jet Engine)	0.08	1.7%
High Pressure Turbine	0.08	1.6%
Controls	0.07	1.5%
Condensing System	0.07	1.4%
Wet Scrubbers	0.07	1.4%
Generator	0.06	1.3%
All other causes	1.14	23.4%
PJM EFOF 2008	4.86	100.0%

Table 5-20 shows that boiler tube leaks, at 19.7 percent of the systemwide EFOF, were the largest single contributor to EFOF. Forced outages because of boiler tube leaks reduced system equivalent availability by 0.96 percentage points. Economic reasons caused the second largest reduction to equivalent availability by 0.60 percentage points. Low pressure turbine problems caused the third largest reduction to equivalent availability by 0.29 percentage points, or 6.0 percent of the systemwide EFOF.

Table 5-21 shows the categories which are included in the economic category.[58] Lack of fuel that is considered out of management control accounted for 96.0 percent of all economic reasons while the lack of fuel that was not out of management control accounted for only 1.1 percent. Lack of water (hydro) was included in the lack of fuel (OMC) calculation.

Table 5-21 Contributions to Economic Outages: 2008

	Contribution to Economic Reasons
Lack of Fuel (OMC)	95.9%
Core Coastdown (Nuclear)	2.1%
Lack of Fuel (Non-OMC)	1.1%
Fuel Conservation	0.5%
Other Economic Problems	0.4%
Lack of Water (Hydro)	0.1%

Table 5-22 Contribution to EFOF by unit type for the most prevalent causes: Calendar year 2008

	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	System
Boiler Tube Leaks	2.9%	0.0%	0.0%	0.0%	0.0%	26.1%	19.7%
Economic	1.1%	14.1%	4.1%	1.3%	3.3%	14.6%	12.4%
Low Pressure Turbine	0.0%	0.0%	0.0%	0.0%	58.2%	1.9%	6.0%
Boiler Air and Gas Systems	0.8%	0.0%	0.0%	0.0%	0.0%	6.3%	4.8%
Boiler Fuel Supply from Bunkers to Boiler	0.3%	0.0%	0.0%	0.0%	0.0%	5.9%	4.4%
Feedwater System	2.9%	0.0%	0.0%	0.0%	6.9%	3.4%	3.3%
Miscellaneous (Generator)	14.7%	9.6%	0.5%	33.9%	1.6%	1.0%	3.2%
Stack Emission	0.1%	0.2%	0.0%	0.0%	0.0%	4.0%	3.0%
Fuel Quality	1.1%	0.1%	9.3%	0.0%	0.0%	3.5%	2.7%
Circulating Water Systems	6.6%	0.0%	0.0%	0.0%	1.0%	2.4%	2.4%
Electrical	5.0%	5.6%	2.2%	3.4%	0.8%	1.9%	2.4%
Miscellaneous (Steam Turbine)	3.3%	0.0%	0.0%	0.0%	2.6%	1.6%	1.7%
Performance	2.4%	7.1%	1.2%	14.2%	3.4%	0.8%	1.7%
Miscellaneous (Jet Engine)	0.0%	21.0%	0.0%	0.0%	0.0%	0.0%	1.7%
High Pressure Turbine	4.2%	0.0%	0.0%	0.0%	0.1%	1.7%	1.6%
Controls	1.5%	0.9%	1.4%	6.2%	1.1%	1.6%	1.5%
Condensing System	1.4%	0.0%	0.0%	0.0%	2.0%	1.5%	1.4%
Wet Scrubbers	0.0%	0.0%	0.0%	0.0%	0.0%	1.9%	1.4%
Generator	7.4%	3.0%	0.8%	0.5%	0.0%	0.5%	1.3%

58 The classification and definitions of these outages are defined by NERC GADS.

Table 5-22 shows the major causes of EFOF by unit type. Boiler tube leaks caused 26.1 percent of the EFOF for fossil steam units. Low pressure turbine problems caused 58.2 percent of the EFOF for nuclear units. Miscellaneous (generator) outages caused 33.9 percent of the EFOF for hydroelectric units. Some miscellaneous generator outages include outages caused by problems with the generator's output breaker, the generator's main leads, or other miscellaneous generator problems.[12]

Table 5-23 Contribution to EFOF by unit type: Calendar year 2008

	EFOF	Contribution to EFOF
Combined cycle	3.4%	8.6%
Combustion turbine	2.7%	7.9%
Diesel	7.3%	0.3%
Hydroelectric	2.0%	0.7%
Nuclear	2.0%	7.8%
Steam	7.3%	74.7%
PJM systemwide	4.9%	100.0%

The contribution to systemwide EFOF by a generator or group of generators is a function of duty cycle, EFORd and share of the systemwide capacity mix. For example, fossil steam units have the largest share (about 49.8 percent) of the capacity mix,[59] have a high duty cycle and in 2008 had an EFORd of 9.8 percent which yields a 74.7 percent contribution to PJM systemwide EFOF. Nuclear units also have a high duty cycle; their share of the PJM systemwide capacity mix is about 18.4 percent and in 2008 they had a 1.9 percent EFORd which yields a 7.8 percent contribution to PJM systemwide EFOF. By using the values in Table 5-23 and Table 5-22 one can determine how much the individual unit types' causes contributed to PJM systemwide EFOF. For instance the value for boiler tube leaks in Table 5-22 multiplied by the contribution value in Table 5-23 for the same unit type will yield the percent contribution to the PJM systemwide EFOF for that outage cause.

59 See the *2008 State of the Market Report*, Volume II, Section 3, "Energy Market, Part 2," "Existing and Planned Generation," at Table 3-37, " Existing PJM capacity 2008 (By zone and unit type (MW))."

Outages Deemed Outside Management Control

In 2006, NERC created specifications for certain types of outages to be deemed outside management control (OMC) in response to the system disturbance of August 14, 2003.[60] NERC specified, in its January 2006 update to the "Generator Availability Data System Data Reporting Instructions,"[61] in Appendix K,[62] that each OMC outage must be carefully considered as to its cause and nature. An outage can be classified as an OMC outage only if the generating unit outage was caused by other than failure of the owning company's equipment or other than the failure of the practices, policies and procedures of the owning company. Appendix K of the "Generator Availability Data Systems Data Reporting Instructions" lists specific cause codes (i.e., codes that are standardized for specific outage causes) that would be considered OMC outages.[63] Not all outages caused by the factors in these specific OMC cause codes are OMC outages. For example, fuel quality issues (i.e., codes 9200 to 9299) may be within the control of the owner or outside management control. Each outage must be considered per the NERC directive. In 2007, PJM removed the OMC designation from all of the fuel quality codes with the exception of 9250, "low Btu coal" since only that code had both an OMC and non-OMC code (i.e., 9250, OMC code for "low Btu coal"; 9251, non-OMC code for "low Btu coal"). After analyzing the data for these outages types, it was found that in 2006, of 17 companies that used either of these cause codes, only three had used both the OMC and non-OMC cause codes. In other words, 14 companies exclusively used the OMC cause code. In 2007, however, of 39 companies that used either of the OMC and non-OMC fuel quality cause codes, only one company exclusively used the OMC cause code. Finally, in 2008, of those same 39 companies that used either OMC and non-OMC fuel quality cause codes, no company exclusively used the OMC cause code. In 2006, approximately 51 percent of the lost generation because of "low Btu coal" was deemed OMC by the generation owners. In 2007, 6 percent of the lost generation because of "low Btu coal" was deemed OMC and in 2008, 12 percent of the lost generation because of "low Btu coal" was deemed OMC. It is not clear why some companies, in 2006, exclusively used the OMC cause codes and did not use the non-OMC cause code for "low Btu coal." In 2007 and 2008, companies seem to have used the non-OMC and OMC cause codes for fuel quality more carefully. It is a reasonable expectation that companies would monitor coal quality stringently and reject noncompliant shipments. It is also possible that these outages are a function of issues with generating plant equipment. PJM should scrutinize OMC outages for low Btu coal carefully.

All outages, including OMC outages, are included in the EFORd that is used for planning studies that determine the reserve requirement. However, OMC outages are excluded from the calculations used to determine the level of unforced capacity for specific units and thus the amount of unforced capacity for sale in Capacity Markets. This modified EFORd is termed the XEFORd. All submitted OMC outages are reviewed by PJM's Capacity Adequacy Department. Table 5-24 shows the impact of OMC outages on EFORd for 2008. The difference is especially noticeable for steam units and combustion turbine units. For steam units, the OMC outage reason that resulted in the highest total MW loss in 2008 was lack of fuel. Although not sub-categorized in the table shown below, most of the difference in the steam XEFORd compared to EFORd is from petroleum-fired steam units

60 NERC had always provided cause codes for outages that were caused by external forces. However, as a result of the system disturbance on August 14, 2003, NERC specifically created outage specifications for outages that were "outside management control."

61 The "Generator Availability Data System Data Reporting Instructions" can be found on the NERC Web site: <http://www.nerc.com/files/2009 GADS DRI Complete Set.pdf> (4.9 MB).

62 The "Generator Availability Data System Data Reporting Instructions," Appendix K can be found on the NERC Web site: <http://www.nerc.com/files/Appendix K Outside Plant Management Control.pdf> (161 KB).

63 For a list of these cause codes, see the *2008 State of the Market Report*, Volume II, Appendix E, "Capacity Market."

and not coal-fired plants. Combustion turbine units have natural gas fuel curtailment outages that are also deemed as OMC. If companies' natural gas fuel supply is curtailed because of pipeline issues, the event can be deemed OMC. However, natural gas curtailments caused by lack of firm transportation contracts or arbitraging transportation reservations should not be classified as OMC. In 2008, XEFORd was 1.3 percentage points less than EFORd, which translates into a 2,155 MW difference in unforced capacity.

Table 5-24 PJM EFORd vs. XEFORd: Calendar year 2008

	2008 EFORd	2008 XEFORd	Difference
Combined cycle	3.4%	3.3%	0.1%
Combustion turbine	10.9%	7.4%	3.5%
Diesel	9.6%	9.0%	0.6%
Hydroelectric	2.4%	1.7%	0.7%
Nuclear	1.9%	1.9%	0.0%
Steam	9.8%	8.5%	1.4%
Overall	7.4%	6.1%	1.3%

SECTION 6 – ANCILLARY SERVICE MARKETS

The United States Federal Energy Regulatory Commission (FERC) defined six ancillary services in Order 888: 1) scheduling, system control and dispatch; 2) reactive supply and voltage control from generation service; 3) regulation and frequency response service; 4) energy imbalance service; 5) operating reserve – synchronized reserve service; and 6) operating reserve – supplemental reserve service.[1] Of these, PJM currently provides regulation, energy imbalance, synchronized reserve, and operating reserve – supplemental reserve services through market-based mechanisms. PJM provides energy imbalance service through the Real-Time Energy Market. PJM provides the remaining ancillary services on a cost basis.

Regulation matches generation with very short-term changes in load by moving the output of selected resources up and down via an automatic control signal.[2] Regulation is provided, independent of economic signal, by generators with a short-term response capability (i.e., less than five minutes) or by demand-side response (DSR). Longer-term deviations between system load and generation are met via primary and secondary reserve and generation responses to economic signals. Synchronized reserve is a form of primary reserve. To provide synchronized reserve a generator must be synchronized to the system and capable of providing output within 10 minutes. Synchronized reserve can also be provided by DSR. The term, Synchronized Reserve Market, refers only to supply of and demand for Tier 2 synchronized reserve.

Both the Regulation and Synchronized Reserve Markets are cleared on a real-time basis. A unit can be selected for either regulation or synchronized reserve, but not for both. The Regulation and the Synchronized Reserve Markets are cleared interactively with the Energy Market and operating reserve requirements to minimize the cost of the combined products, subject to reactive limits, resource constraints, unscheduled power flows, interarea transfer limits, resource distribution factors, self-scheduled resources, limited fuel resources, bilateral transactions, hydrological constraints, generation requirements and reserve requirements.

On June 1, 2008 PJM introduced the Day-Ahead Scheduling Reserve Market (DASR), as required by the settlement in the RPM case.[3] The purpose of this market is to satisfy supplemental (30-minute) reserve requirements with a market-based mechanism that allows generation resources to offer their reserve energy at a price and compensates cleared supply at the market clearing price.

PJM does not provide a market for reactive power, but does ensure its adequacy through member requirements and scheduling. Generation owners are paid according to the FERC-approved, reactive revenue requirements. Charges are allocated to network customers based on their percentage of load, as well as to point-to-point customers based on their monthly peak usage.

PJM does not provide a market for black start services, which are procured and paid zonally, but does ensure that there are adequate black start resources.

1 75 FERC ¶ 61,080 (1996).
2 Regulation is used to help control the area control error (ACE). See *2008 State of the Market Report,* Volume II, Appendix F, "Ancillary Service Markets," for a full definition and discussion of ACE. Regulation resources were almost exclusively generating units in 2008.
3 See PJM Interconnection, L.L.C., 117 FERC ¶ 61,331 (2006).

The MMU analyzed measures of market structure, conduct and performance of the PJM Regulation Market and of its two Synchronized Reserve Markets for 2008, comparing market results to 2007. The Market Monitoring Unit (MMU) also analyzed measures of market structure, conduct and performance of the PJM DASR Market from June 1 through December 31, 2008.

Overview

Regulation Market

There were no major structural changes to the PJM Regulation Market in 2008 which continues to be operated as a single market. On December 1, 2008, PJM implemented several changes to the Regulation Market including the introduction of the three pivotal supplier test for market power, a change to the calculation of lost opportunity cost and a change to the treatment of regulation revenues with respect to operating reserve credits.

Market Structure

- **Supply.** During 2008, the supply of offered and eligible regulation in PJM was generally both stable and adequate. Although PJM rules allow up to 25 percent of the regulation requirement to be satisfied by demand resources, none qualified to make regulation offers in 2008. The ratio of eligible regulation offered to regulation required averaged 2.39 throughout 2008.

- **Demand.** From January 1 through August 7, 2008, PJM calculated the regulation requirement for all hours of the day as 1.0 percent of the peak load forecast for the operating day. This requirement was established in August 2006. Beginning August 7, PJM began to calculate on-peak and off-peak regulation requirement. The on-peak requirement is equal to 1.0 percent of the forecast peak load for the PJM RTO for the day. The PJM RTO off-peak Regulation Requirement is equal to 1.0 percent of the forecast valley load for the PJM RTO for the day. The average hourly regulation demand in 2008 was 922 MW. For the winter the demand was 960 MW; for the spring it was 834 MW; for the summer it was 1,064 MW; and for the fall it was 815 MW. For the months of August through December, average off-peak regulation demand was 665 MW while average on-peak demand was 881 MW.

- **Market Concentration.** During 2008, the PJM Regulation Market had a load weighted, average Herfindahl-Hirschman Index (HHI) of 1283 which is classified as "moderately concentrated."[4] The load weighted average HHI before August 1 (when the requirement was fixed for all hours of the day) was 1226. The load weighted average HHI after August 1 when the requirement was lower for off-peak hours, was 1397. The minimum hourly HHI was 707 and the maximum hourly HHI was 2767. The largest hourly market share in any single hour was 58 percent, and 63 percent of all hours had a maximum market share greater than 20 percent. In 2008, 82 percent of hours had three or fewer pivotal suppliers. The MMU concludes from these results that the PJM Regulation Market in 2008 was characterized by structural market power in 82 percent of the hours.

4 See the *2008 State of the Market Report*, Volume II, Section 2, "Energy Market, Part I," at "Market Concentration" for a more complete discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI).

Market Conduct

- **Offers.** From January through November 2008 regulation offer prices were provided by the unit owner, applicable for the entire operating day and, with lost opportunity cost (LOC), comprised the total offer to the Regulation Market. The regulation offer price was subject to a $100 per MWh offer cap, with the exception of the two dominant suppliers, whose offers were capped at marginal cost plus $7.50 per MWh plus LOC. All suppliers are paid the market-clearing price. Beginning December 1, 2008 PJM implemented a three pivotal supplier test in the regulation market. As part of the implementation, owners are required to submit unit specific cost based offers which may include up to a $12/MWh margin adder and owners have the option to submit price based offers. All offers remain subject to the $100 per MWh cap. All units owned by owners who fail the three pivotal supplier test for an hour are dispatched at the lesser of their cost based or price based offer. As part of the changes to the regulation market implemented on December 1, 2008, PJM no longer nets regulation revenue above offer price against operating reserve revenue and PJM now calculates lost opportunity costs using the lower of cost based or price based offers as the reference rather than the cost based offer.

Market Performance

- **Price.** For the PJM Regulation Market during 2008 the load weighted, average price per MWh (i.e., the regulation market clearing price, including LOC) associated with meeting PJM's demand for regulation was $42.09. This represents an increase of $5.37 from the average price for regulation during 2007. From January through November 2008, based on MMU estimates of the marginal cost of regulation, offers at levels greater than competitive levels set the clearing price for regulation in about 18 percent of all hours. On December 1, 2008, PJM implemented new Regulation Market rules that cost cap units offered by suppliers which are pivotal and allow price based offers for units whose suppliers are not.

Synchronized Reserve Market

There were no major structural changes to the PJM Synchronized Reserve Market in 2008.[5] Throughout 2008 PJM retained the two synchronized reserve markets it implemented on February 1, 2007. The RFC Synchronized Reserve Zone reliability requirements are set by the Reliability*First* Corporation. The Southern Synchronized Reserve Zone (Dominion) reliability requirements are set by the Southeastern Electric Reliability Council (SERC).

In September 2008, PJM made a change to the market clearing software, Synchronized Reserve and Regulation Optimizer (SPREGO), designed to improve the accuracy of Tier 1 estimates and reduce the amount of Tier 2 synchronized reserve called by PJM dispatchers after the market cleared. These additional assignments made by the dispatchers are to meet increases in required synchronized reserves that occur after needed synchronized reserve is first forecast 90 minutes before the operating hour. The changes were made to address a problem in the Synchronized Reserve Market that has been persistent since late 2007.

5 In PJM, the term, Synchronized Reserve Market, refers to Tier 2 synchronized reserve. Synchronized Reserve as it is used here is 10-minute operating reserve.

In mid-January 2009, PJM Market Operations took the unusual step of recalculating, revising, and reposting synchronized reserve market clearing prices for November and early December 2008. Some hours had been erroneously calculated because validation data required by a software change had not been entered. In all, nine hours were reposted. The price changes ranged from a reduction of $30.38 to a reduction of $429.83 and included one hour where there was a price increase of $11.23.

Market Structure

- **Supply.** During 2008, the offered and eligible excess supply ratio was 1.41 for the PJM Mid-Atlantic Synchronized Reserve Region.[6] The excess supply ratio is determined using the administratively required synchronized reserve. The actual requirement for Tier 2 synchronized reserve is lower because there is usually a significant amount of Tier 1 synchronized reserve available. Throughout 2008, the MW contribution of DSR resources to the Synchronized Reserve Market remained significant and resulted in lower overall Synchronized Reserve prices.

- **Demand.** The average synchronized reserve requirements were 1,310 MW for the RFC Synchronized Reserve Zone and 1,160 MW for the Mid-Atlantic Subzone. These requirements are a function of administratively determined, regional requirements established by each market zone's reliability council. Since there was usually enough Tier 1 in the RFC Synchronized Reserve Zone to cover the requirement, only 5 percent of hours cleared a Tier 2 Synchronized Reserve market in the RFC. For the Southern Synchronized Reserve Zone only 1.5 percent of the hours had a non-zero Tier 2 requirement in 2008. Market demand is less than the requirement by the amount of forecast Tier 1 synchronized reserve available at the time a Synchronized Reserve Market is cleared. The average demand for Tier 2 synchronized reserve in the Mid-Atlantic Subzone of the RFC Synchronized Reserve Zone was 153 MW. Demand for Tier 2 Synchronized Reserve fell sharply in December as a result of a large increase in the forecast Tier 1 available. The average demand for Tier 2 synchronized reserve in the Southern Synchronized Reserve Zone was 1.5 MW. All demand for Tier 2 in the Southern Synchronized Reserve Zone was satisfied by 15-minute quick start units. A Southern Synchronized Reserve Zone market did not clear in any hours in 2008.

  The purchase of additional Tier 2 synchronized reserves by dispatchers after synchronized reserve market settlement continued to be an issue in 2008. In 2008, 44 percent of all Tier 2 synchronized reserves were added after the market cleared. It is clear that, in actual operations, PJM dispatch identifies a need for more Tier 2 synchronized reserve, or differently located synchronized reserve, than is being forecast and scheduled through the Tier 2 Synchronized Reserve Market. It is clear that there is a difference in the calculation of the need for Tier 2 synchronized reserves between the market solution and the operators. The reason remains under investigation.

6 The Synchronized Reserve Market in the Southern Region cleared in so few hours that related data for that market is not meaningful.

- **Market Concentration.** Although lower than in 2007, market concentration in the Tier 2 Synchronized Reserve Markets remained high in 2008. The average load weighted cleared Synchronized Reserve Market HHI for the Mid-Atlantic Subzone of the RFC Synchronized Reserve Zone throughout 2008 was 2844. Slightly less than one percent of all hours had a market share of 100 percent. In 56 percent of hours the maximum market share was greater than 40 percent (compared to 76 percent of hours in 2007). In the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market, in 2008, 96 percent of hours had three or fewer pivotal suppliers. The MMU concludes from these results that the PJM Synchronized Reserve Markets in 2008 were characterized by structural market power.

Market Conduct

- **Offers.** The offer price is provided by the unit owner, is applicable for the entire operating day and, with lost opportunity cost calculated by PJM, comprises the merit order price to the Synchronized Reserve Market. The synchronized reserve offer made by the unit owner is subject to an offer cap of marginal cost plus $7.50 per MW, plus lost opportunity cost. All suppliers are paid the higher of the market clearing price or their offer plus their unit specific opportunity cost.

Market Performance

- **Price.** The load weighted, average PJM price for Tier 2 synchronized reserve in the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market was $10.65 per MW in 2008, a $5.63 per MW decrease from 2007.

- **Demand.** There was a significant change in the operation of the Synchronized Reserve Market in the last quarter of 2007 as PJM relied less on the market and more on out of market purchases of spinning reserve for local needs. This continued throughout 2008. The increase in out of market purchases indicates that the Synchronized Reserve Market is not functioning to adequately coordinate supply and demand. It is not clear why the demand identified in the market solution is consistently less than the demand identified by the system operators.

- **DSR.** Demand side resources began participating in the Synchronized Reserve Markets in August 2006. Participation of demand response grew significantly in late 2007, leveled off through August of 2008 and rose significantly in September through December of 2008. In 32 percent of hours during 2008 in which a Tier 2 Synchronized Reserve Market was cleared for the Mid-Atlantic Subzone, all synchronized reserve was provided by DSR.

- **Availability.** A synchronized reserve deficit occurs when the combination of Tier 1 and Tier 2 synchronized reserve is not adequate to meet the synchronized reserve requirement. Neither PJM Synchronized Reserve Market experienced deficits during 2008.

DASR

On June 1, 2008 PJM introduced the Day-Ahead Scheduling Reserve Market (DASR), as required by the RPM settlement.[7] The purpose of this market is to satisfy supplemental (30-minute) reserve requirements with a market-based mechanism that allows generation resources to offer their reserve energy at a price and compensates cleared supply at a single market clearing price. The DASR 30-minute reserve requirements are determined by the reliability region.[8] The RFC and Dominion DASR requirements are added together to form a single RTO DASR Requirement which is obtained via the DASR Market. The requirement is applicable for all hours of the operating day. If the DASR Market does not result in procuring adequate scheduling reserves, PJM is required to schedule additional operating reserves.

Market Structure

The DASR Market in 2008 had three pivotal suppliers in a monthly average of 45 percent of all hours. The number of hours in which the DASR Market had three pivotal suppliers declined in November and December. The MMU concludes from these results that the PJM DASR Market in 2008 was characterized by structural market power.

Market Conduct

In December, about 6 percent of all units engaged in economic withholding from the DASR Market by providing high offer prices. Conversely, about 48 percent of units had offers of $0.00, either by choice or by default.

Market Performance

For June 2008 through December 2008, the load weighted price of DASR was $0.26. DASR prices declined in the last three months of 2008. Demand side resources began to offer and clear in the DASR Market in November and became significant in December.

Black Start

Black start service is necessary to help ensure the reliable restoration of the grid following a black out. Black start service is the ability of a generating unit to start without an outside electrical supply, or is the demonstrated ability of a generating unit with a high operating factor to automatically remain operating at reduced levels when disconnected from the grid.[9]

Individual transmission owners, with PJM, identify the black start units included in each transmission owner's system restoration plan. PJM defines required black start capability zonally and ensures the availability of black start service by charging transmission customers according to their zonal load ratio share and compensating black start unit owners.

7 See PJM Interconnection, L.L.C., 117 FERC ¶ 61,331 (2006).
8 PJM Manual 13, Emergency Requirements, Rev 35, 11/07/2008; pp 11-12.
9 PJM Tariff, Second Revised Sheet No. 33.01, March 1, 2007.

PJM does not have a market to provide black start reserve, but compensates black start resource owners for all costs associated with providing this service, as defined in the tariff. For 2008, charges to PJM members for providing black start services were just over $13 million.

As a consequence of PJM's filing to revise its formula rate for black start service to allow for the recovery of the costs of compliance with Critical Infrastructure Protection standards, these costs likely will increase substantially. The revised rates also better match the sellers' commitment period with the period for cost recovery.

The MMU recommends that PJM, FERC and state regulators reevaluate the way in which black start service is procured in order to ensure that procurement is done in a globally least cost manner.

Conclusion

PJM consolidated its Regulation Markets into a single Combined Regulation Market, on a trial basis, effective August 1, 2005. The MMU has consistently found since that time that the PJM Regulation Market is characterized by structural market power. This conclusion is based on the results of the three pivotal supplier test. In 2008, the MMU cannot conclude that the Regulation Market produced competitive results or noncompetitive results, based on the MMU analysis of the relationship between the offer prices and marginal costs of units that set the price in the Regulation Market, the marginal units, where the MMU finds that prices were set by offers above the competitive level in 18 percent of the hours. The absence of a definitive conclusion is a result of the fact that the cost data are based on MMU estimates rather than data submitted by market participants. It is expected that the application of the three pivotal supplier test will mean that the results of the Regulation Market will be competitive in 2009.

In 2008, PJM and its stakeholders addressed the issue of market power mitigation for the Regulation Market in the Three Pivotal Supplier Task Force (TPSTF), which was convened pursuant to PJM's 2007 Strategic Report to review market power mitigation issues.[10] The TPSTF achieved a consensus supporting the application of the three pivotal supplier (TPS) test to the Regulation Market, provided that three adjustments to the rules were included, all of which increased margins for regulation units. PJM filed the proposed revisions on October 1, 2008.[11] A number of parties filed comments, including the MMU on October 20, 2008.[12] The MMU supported the consensus but requested that the Commission direct the MMU to report on the three adjustments to the rules: increasing the current $7.50 adder to cost based offers to $12; modifying the calculation of opportunity costs to use the lower of cost based or price based offers as the reference; and eliminating the netting of revenues from the Regulation Market from make whole balancing operating reserve payments. The Commission, in accepting PJM's filing on November 26, 2008, directed the Market Monitoring Unit to prepare a report due on November 26, 2009.[13]

10 See PJM 2007 Strategic Report at 65 (April 2, 2007). This report is posted on PJM's Website at: http://www2.pjm.com/documents/downloads/strategic-responses/report/20070402-pjm-strategic-report.pdf.

11 PJM submitted its initial filing in FERC Docket No. ER09-13-000.

12 Comments and Motion for Leave to Intervene of the Independent Market Monitor for PJM, Docket No. ER09-13-000. These comments are posted on the Monitoring Analytics' Website at http://www.monitoringanalytics.com.

13 *PJM Interconnection, L.L.C.*, 125 FERC ¶ 61,231, at P 18 (2008).

On December 1, 2008, the three pivotal supplier test was implemented in the Regulation Market to address the identified market power problems. The one month of data for December 2008, is inadequate to permit a meaningful assessment of the impact of the modifications on the PJM Regulation Market.

The implementation of the three pivotal supplier test is consistent with the longstanding MMU recommendation that real-time, hourly market structure tests be implemented in the Regulation Market, that market power mitigation be applied only for hours in which the market structure is noncompetitive and that market power mitigation be applied only to the companies failing the market structure tests. This more flexible and real-time approach to mitigation represents an improvement over the approach to mitigation which had been in place from August 2005 through November 2008 which required cost based offers from the two dominant suppliers at all times. The three pivotal supplier approach to mitigation also represents an improvement over prior methods of simply defining the market to be noncompetitive and limiting all offers to cost based offers. The real-time approach recognizes that at times the market is structurally competitive and therefore no mitigation is required, that at times the market is not structurally competitive and mitigation is required, and that at times generation owners other than the designated, two dominant suppliers may have structural market power that requires mitigation. The MMU also recommends that the overall $100 regulation offer cap remain in effect. The retention of an overall offer cap together with a real-time, three pivotal supplier test for market structure is identical to PJM's current practice in the Energy Market.

The structure of each Synchronized Reserve Market has been evaluated and the MMU has concluded that these markets are not structurally competitive as they are characterized by high levels of supplier concentration and inelastic demand. (The term Synchronized Reserve Market refers only to Tier 2 synchronized reserve.) As a result, these markets are operated with market-clearing prices and with offers based on the marginal cost of producing the service plus a margin. As a result of these requirements, the conduct of market participants within these market structures has been consistent with competition, and the market performance results have been competitive. Prices for synchronized reserve in the RFC Synchronized Reserve Zone and in the Southern Synchronized Reserve Zone are market-clearing prices determined by the supply curve and the administratively defined demand. The cost based synchronized reserve offers are defined to be the unit specific incremental cost of providing synchronized reserve plus a margin of $7.50 per MWh plus lost opportunity cost calculated by PJM.

The issue of Tier 2 synchronized reserve purchases after market clearing began in the last quarter of 2007. Beginning in October and increasing substantially in November and December 2007, there was an increase in the amount of combustion turbine, synchronized condenser MW added by PJM market operations to the Synchronized Reserve Market after market clearing.

In 2008 PJM continued to rely on non-economic, out of market Tier 2 resources added to the resources procured in the synchronized reserve market. Tier 2 synchronized reserve added after the market cleared accounted for approximately 44 percent of total Tier 2 synchronized reserve purchased in 2008. In September, PJM attempted to address this issue by improving the forecast of Tier 1. PJM added a second Tier 1 estimate performed 30 minutes prior to the operating hour. This did not succeed in reducing the amount of Tier 2 added after market clearing.

In December, a significant increase in the amount of estimated Tier 1 reduced the amount of Tier 2 needed to meet the required synchronized reserve. The increase in the amount of estimated Tier 1 appears to have been the result of a mistake in identifying available Tier 1 resources prior to December. The increase in Tier 1 resources did not reduce the amount of Tier 2 synchronized reserve added to the synchronized reserve market after market clearing. In December, the amount of Tier 2 cleared fell substantially, while the proportion of synchronized reserve added out of market increased significantly.

The continued reliance on out of market purchases indicates that the Synchronized Reserve Market is not functioning to coordinate supply and demand in a way consistent with the need identified for these reserves in real time by PJM operations. It is clear that, in actual operations, PJM dispatch identifies a need for more Tier 2 synchronized reserve, or differently located synchronized reserve, than is being forecast and scheduled through the Tier 2 Synchronized Reserve Market. It is clear that there is a difference in the calculation of the need for Tier 2 synchronized reserves in the Mid-Atlantic subzone between the market solution and the operators. The reason remains under investigation.

The MMU concludes that the DASR Market is not structurally competitive, based on the results in 2008. The MMU recommends that the DASR Market rules be modified to incorporate the application of the three pivotal supplier test. The MMU also concludes that the DASR Market results were competitive in 2008.

The benefits of markets are realized under these approaches to ancillary service markets. Even in the presence of structurally noncompetitive markets, there can be transparent, market clearing prices based on competitive offers that account explicitly and accurately for opportunity cost. This is consistent with the market design goal of ensuring competitive outcomes that provide appropriate incentives without reliance on the exercise of market power and with explicit mechanisms to prevent the exercise of market power.

PJM should continue to consider whether additional ancillary service markets need to be defined in order to ensure that the market is compensating suppliers for services when appropriate.

Overall, the MMU concludes that the Regulation Market's results cannot be determined to have been competitive or to have been noncompetitive, although the implementation of the three pivotal supplier test in the Regulation Market on December 1 is expected to improve the results. The MMU concludes that the Synchronized Reserve Markets' results were competitive and that the differences between the market demand and the operational demand for Synchronized Reserves need to be addressed. The MMU concludes that the DASR Market's results were competitive.

Regulation Market

Market Structure

The market structure of the 2008 PJM Regulation Market remained similar to the market structure of the 2007 Regulation Market. DSR participation was introduced in 2006, but demand-side resources have not yet qualified or made offers in the Regulation Market.

Supply

The supply of regulation can be measured as regulation capability, regulation offered, or regulation offered and eligible. For purposes of evaluating the Regulation Market, the relevant regulation supply is the level of supply that is both offered to the market on an hourly basis and is eligible to participate in the market on an hourly basis. This is the only supply that is actually considered in the determination of market prices. The level of supply that clears in the market on an hourly basis is called assigned regulation or cleared regulation. Assigned regulation is selected from regulation that is eligible to participate.

Regulation capability is the sum of the maximum daily offers for each unit and is a measure of the total volume of regulation capability as reported by resource owners.

Regulation offered represents the level of regulation capability offered to the PJM Regulation Market. Resource owners may offer those units with approved regulation capability into the PJM Regulation Market. PJM does not require a resource capable of providing regulation service to offer its capability to the market. Regulation offers are submitted on a daily basis.

Regulation offered and eligible represents the level of regulation capability offered to the PJM Regulation Market and actually eligible to provide regulation in an hour. Some regulation offered to the market is not eligible to participate in the Regulation Market as a result of identifiable offer parameters specified by the supplier. As an example, the regulation capability of a unit is included in regulation offered based on the daily offer and availability status, but that regulation capability is not eligible in one or more hours because the supplier sets the availability status to unavailable for one or more hours of that same day. (The availability status of a unit may be set in both a daily offer and an hourly update table in the PJM market software.) As another example, the regulation capability of a unit is included in regulation offered if the owner of a unit offers regulation, but that regulation capability is not eligible if the owner sets the unit's economic maximum generation level equal to its economic minimum generation level. In that case, the unit cannot provide regulation and is not eligible to provide regulation. As another example, the regulation capability of a unit is included in regulation offered, but that regulation capability is not eligible if the unit is not operating, unless the unit meets specific operating parameter requirements. A unit whose owner has not submitted a cost based offer will not be eligible to regulate even if the unit is a regulation resource.

Only those offers eligible to provide regulation in an hour are part of supply for that hour, and only eligible offers are considered by PJM for purposes of clearing the market. Regulation assigned represents those regulation resources selected through the regulation market clearing mechanism to provide regulation service for a given hour.

The average eligible regulation supply-to-requirement ratio in the PJM Regulation Market during 2008 was 2.39. Even during periods of diminished supply such as off-peak hours, eligible regulation supply was adequate to meet the regulation requirement.

Demand

Demand for regulation does not change with price, i.e. demand is price inelastic. The demand for regulation is set administratively based on reliability objectives and forecast load. Regulation demand is also referred to in the *2008 State of the Market Report* as "required regulation."

The PJM regulation requirement is set by PJM Interconnection in accordance with NERC control standards. In August 2008 the requirement was adjusted to be 1.0 percent of the forecast peak load for on peak hours and 1.0 percent of the forecast valley load for off peak hours.[14] During 2008 the PJM regulation requirements ranged from 523 MW to 1,329 MW. The average required regulation was 922 MW (Table 6-1).

Table 6-1 PJM Regulation Market Required MW and Ratio of Supply to Requirement

Period Type	Average Required Regulation (MW)	Ratio of Supply to Requirement
All of 2008	922	2.39
Winter	960	2.52
Spring	834	2.44
Summer	1064	2.19
Fall	815	2.44
August through December Off Peak	665	2.87
August through December On Peak	881	2.43

Market Concentration

Market Structure Definitions

The market structure analysis follows the FERC logic specified in the AEP Order.[15] The logic of the delivered price test is followed by calculating market share, HHI and pivotal supplier metrics for each market configuration.[16] The analysis here includes a broader definition of the relevant competitive offers, defined as those offered and eligible units that could provide regulation at less than, or equal to, 1.5 times the clearing price. In addition, the analysis here includes the result of the three pivotal supplier test. In all cases, regulation must be both offered and eligible in an hour in order for it to be part of the market. This is termed economic capacity under the delivered price test.

The delivered price test may also be applied using available economic capacity, defined as gross supply by participants net of their load obligation. The fact that suppliers have load obligations may affect their incentives to exercise market power although not unambiguously. However, as the amount of load that will be served by the integrated utilities in the future is unknown given the

14 See Reliability*First* Corporation <http://www.rfirst.org/> (1 KB).
15 107 FERC ¶ 61,018 (2004) (AEP Order) and 108 FERC ¶ 61,026 (2004) (AEP Order on Rehearing).
16 AEP Order at 105 *et seq.*

unknown extent of retail competition, a reasonable approach is to evaluate the entire regulation supply, or economic capacity, as is done here.

The FERC's AEP Order indicates that failure of any one of the specified tests is adequate for a showing of market power including tests based on market concentration, market share and pivotal supplier analyses. The analysis presented here goes further in order to analyze the significance of excess supply. The MMU applies the pivotal supplier test using three pivotal suppliers. In addition, when there are hours with three pivotal suppliers, the analysis also examines the frequency with which individual generation owners are in the pivotal group. If the hours that fail a pivotal supplier test have the same pivotal supplier(s) for a significant proportion of the hours, that information can be used to identify dominant suppliers.

The pivotal supplier test represents an analytical approach to the issue of excess supply. Excess supply, by itself, is not adequate to ensure a competitive outcome. A monopolist could have substantial excess supply, but the monopolist would not be expected to change its market behavior as a result. The same logic applies to a small group of dominant suppliers. However, if there is adequate supply without the three dominant suppliers to meet the demand, then the market structure can reasonably be deemed competitive.

PJM Regulation Market

During 2008 the PJM Regulation Market total capability was 7,326 MW.[17] Total capability is a theoretical measure which is never actually achieved. The level of regulation resources offered on a daily level and the level of regulation resources eligible to participate on an hourly level in the market were lower than the total regulation capability. In 2008 the average daily offer level was 4,983 MW or 68 percent of total capability while the average hourly eligible offer level was 2,183 MW or 30 percent of total capability. In 2008 the average hourly eligible offer level was 44 percent of the average daily offer level. Although regulation is offered daily, eligible regulation changes hourly. Typically less regulation is eligible during off-peak hours because fewer steam units are running during those hours. Table 6-2 shows capability, daily offer and average hourly eligible MW for all hours as well as for off-peak and on-peak hours.

Table 6-2 PJM regulation capability, daily offer and hourly eligible: Calendar year 2008

Period	Regulation Capability (MW)	Average Daily Offer (MW)	Percent of Capability Offered	Average Hourly Eligible (MW)	Percent of Capability Eligible
All Hours	7,326	4,983	68%	2,183	30%
Off Peak	7,326	NA	NA	1,936	26%
On Peak	7,326	NA	NA	2,481	34%

The ratio of the hourly eligible regulation supply to the hourly regulation requirement averaged 2.39 for PJM during 2008. When this ratio equals 1.0, it indicates that offered supply exactly equals demand for the referenced time period.

17 Total offer capability is defined as the sum of the maximum daily offer volume for each offering unit during the period, without regard to the actual availability of the resource or to the day on which the maximum was offered.

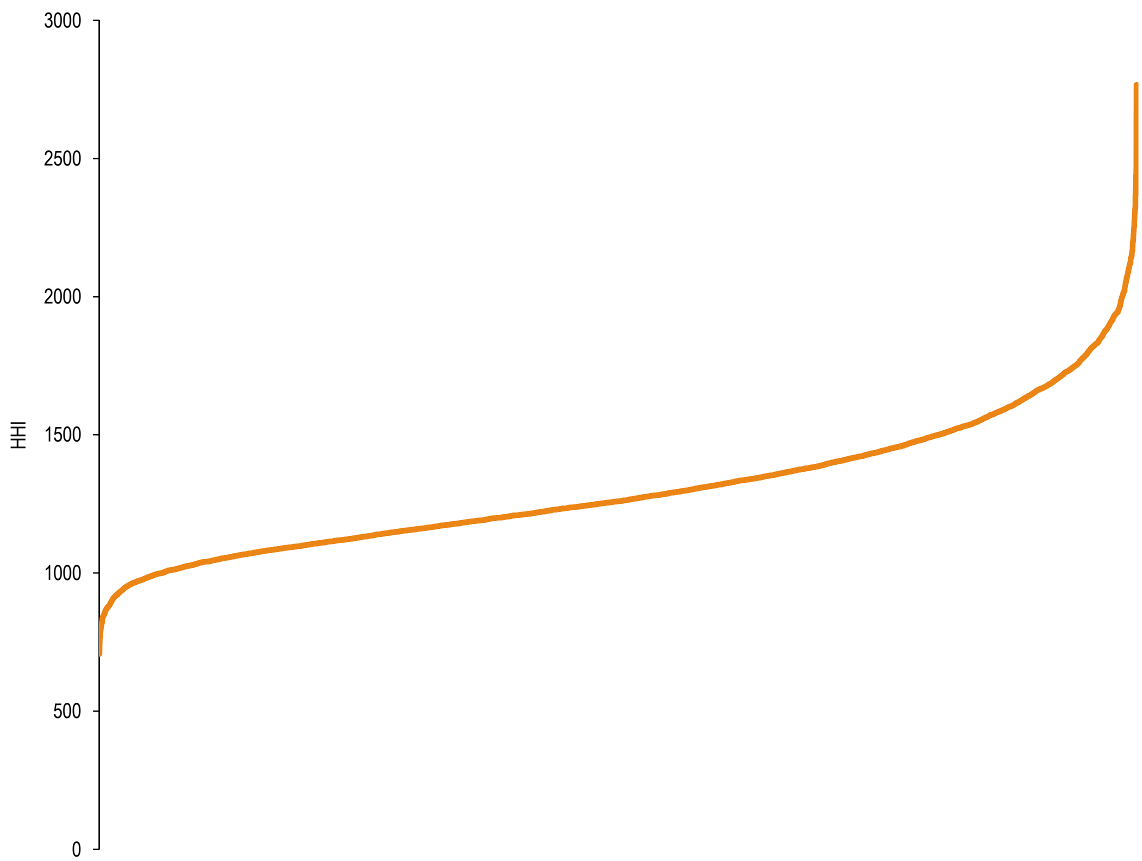
Hourly HHI values were calculated based on cleared regulation. In 2008 HHI values ranged from a maximum of 2767 to a minimum of 707, with a load weighted average value of 1291, which is categorized as moderately concentrated by the FERC definitions. Table 0-3 summarizes the 2008 PJM Regulation Market HHIs and includes HHIs separately for the periods before and after August 2008 to show the impact of the reduction in required regulation.

Table 6-3 PJM cleared regulation HHI: Calendar year 2008

Market Type	Minimum HHI	Load-Weighted Average HHI	Maximum HHI
Cleared Regulation, 2008	707	1290	2767
Cleared Regulation, January through July	707	1226	2767
Cleared Regulation, August through December	736	1397	2480

The PJM Regulation Market exhibited consistent moderate market concentration with about 5.9 percent of the periods with an HHI less than 1000 and about 4.7 percent of the periods with an HHI greater than 1800. See the HHI distribution curve in Figure 6-1.

Figure 6-1 PJM Regulation Market HHI distribution: Calendar year 2008



The largest hourly market share for cleared regulation was 49 percent, and 63 percent of all hours had a maximum market share greater than 20 percent. Although most hours had a market participant with a market share greater than 20 percent, the highest annual average hourly market share by a company was 17.3 percent. The top four annual average hourly market shares for cleared regulation in 2008 are listed in Table 6-4.

Table 6-4 Highest annual average hourly Regulation Market shares: Calendar year 2008

Company Market Share Rank	Cleared Regulation Top Market Shares
1	17%
2	14%
3	10%
4	9%

In 2008, 83 percent of hours failed the three pivotal supplier test. This means that for 83 percent of hours the total regulation requirement could not be met in the absence of the three largest suppliers. One supplier of regulation was pivotal in 89 percent of three pivotal hours. A second company was pivotal in 85 percent of the three pivotal hours. A third company was pivotal in 61 percent of three pivotal hours. Table 6-5 includes a monthly summary of three pivotal supplier results.

Table 6-5 Regulation market monthly three pivotal supplier results: Calendar year 2008

Month	Hours With Three Pivotal Suppliers
Jan	84%
Feb	83%
Mar	89%
Apr	88%
May	97%
Jun	77%
Jul	75%
Aug	80%
Sep	74%
Oct	89%
Nov	59%
Dec	92%

Thus, in addition to failing the three pivotal supplier test in a significant number of hours, the pivotal suppliers in the Regulation Market were the same suppliers in the majority of hours when the test was failed. This is a further indication that the structural market power issue in the Regulation Market remained persistent and repeated during 2008.

The MMU concludes from these results that the PJM Regulation Market in 2008 was characterized by structural market power. This conclusion is based on the results of the three pivotal supplier test.

Market Conduct

Offers

PJM implemented the three pivotal supplier test in the Regulation Market in December 2008. As a result, generators wishing to participate in the PJM Regulation Market must submit cost based regulation offers for specific units by 1800 Eastern Prevailing Time (EPT) of the day before the operating day. Generators may also submit price based offers. The regulation cost based offer price is limited to costs plus $12.00. The costs are validated in accordance with unit specific operating parameters entered with the cost based offer. A unit is not required to provide these parameters if its offer is less than $12.00. The unit specific operating parameters are heat rate at economic maximum, heat rate at regulation minimum, VOM rate and fuel cost. Regulation offers are applicable for the entire 24 hour period for which they are submitted. As in any competitive market, regulation offers at marginal cost are considered to be competitive.

The cost based and price based offers and the associated cost related parameters are the only components of the regulation offer applicable for the entire operating day. The following information must be included in each offer, but can be entered or changed up to 60 minutes prior to the operating hour: regulating status (i.e., available, unavailable or self-scheduled); regulation capability; regulation minimum (may be increased but not decreased); and regulation maximum (may be decreased but not increased). The Regulation Market is cleared on a real-time basis and regulation prices are posted hourly throughout the operating day. The amount of self-scheduled regulation is confirmed 60 minutes before each operating hour, and regulation assignments are made at least 30 minutes before each operating hour.

PJM's Regulation Market is cleared hourly, based on both offers submitted by the units and the hourly lost opportunity cost of each unit, calculated based on the forecast LMP at the location of each regulating unit.[18] The total offer price is the sum of the unit specific offer and the opportunity cost. In order to clear the market, PJM ranks the cost based offers of all offered and eligible regulating resources in ascending total offer price order; it does the same for synchronized reserve and simultaneously determines the least expensive set of resources necessary to provide regulation, synchronized reserve and energy for the operating hour, taking into account any resources self-scheduled to provide any of these services. Units are assigned to regulate in ascending merit order by price until the required regulation is satisfied. The resulting assignments are evaluated to see which if any of the owning companies are pivotal. Pivotal companies will have their resources offer capped at the lesser of their cost based or price based offer. The generating units of companies which are not pivotal will then have their offer reset to their price based offer and the market is cleared.[19] The Regulation Market price that results is the RMCP and the unit that sets this price is the marginal unit.

18 PJM estimates the opportunity cost for units providing regulation based on a forecast of locational marginal price (LMP) for the upcoming hour. In September 2008, PJM also began including the lost opportunity cost impact in adjoining hours of dispatching a unit to its regulation set point. As part of the settlement that included the implementation of the three pivotal supplier test on December 1, 2008, the LOC calculator now uses the lesser of the available price based energy schedule or the most expensive available cost based energy schedule.

19 See PJM, "Manual-11: Scheduling Operations," Revision 38 (Redline), Regulation Market Clearing, (January 15, 2009) (accessed February 23, 2009), p. 37.

In 2008, offers from some regulation suppliers exceeded the competitive level. Based on the MMU's estimates of unit specific cost data, 18 percent of marginal unit daily offers exceeded marginal costs. The competitive offer level for regulation, as for any other market, is the marginal cost of providing regulation. For the PJM Regulation Market, the marginal cost has been defined as the calculated cost plus a margin of $7.50 per MWh, through November 2008. From January through November 2008, the cost of providing regulation was not provided by suppliers. The MMU had long recommended that the provision of such data be required and although PJM systems were created to allow the provision of cost data, provision of the data had not been mandatory. In December 2008, with the introduction of the three pivotal supplier test in the regulation market, suppliers of regulation are required to provide cost data if their cost based offer exceeds $12/MWh.

Market Performance

Price

Figure 6-2 shows the daily average regulation market clearing price and the opportunity cost component for the marginal units in the PJM Regulation Market. All units chosen to provide regulation received as payment the higher of the clearing price multiplied by the unit's assigned regulating capability, or the unit's regulation offer multiplied by its assigned regulating capability plus the individual unit's real-time opportunity cost.[20]

From January through November 2008, offers at levels greater than the competitive level set the clearing price for regulation in 18 percent of hours.[21] In eight percent of hours offers were greater than $5.00 per MW above the competitive level; in seven percent of hours offers were greater than $10.00 per MWh above the competitive level; and in one percent of hours the marginal unit offer was greater than $15.00 per MWh above the competitive level. To put these results in context, the load weighted, average offer price for all marginal units in the PJM Regulation Market during 2008 was $11.94, so an additional $5.00 per MWh is a markup of approximately 42 percent. These results mean that the MMU cannot conclude that the Regulation Market results were competitive in 2008 or that the Regulation Market results were noncompetitive. The absence of a definitive conclusion is a result of the fact that the cost data are based on MMU estimates rather than data submitted by market participants. The MMU supports the change to the regulation market rules on December 1, 2008 requiring participants to submit the cost of regulation consistent with the definitions in PJM's "Cost Development Guidelines."[22]

Regulation credits are awarded to generation owners that have either self-scheduled or sold regulation into the market. Regulation credits for units self-scheduled to provide regulation are equal to the RMCP times the unit's self-scheduled regulating capability. Regulation credits for units that offer regulation into the market and are selected to provide regulation are the higher of the RMCP times the unit's assigned regulating capability, or the unit's regulation offer times its assigned regulating capability plus the opportunity cost that the unit has incurred. Although most

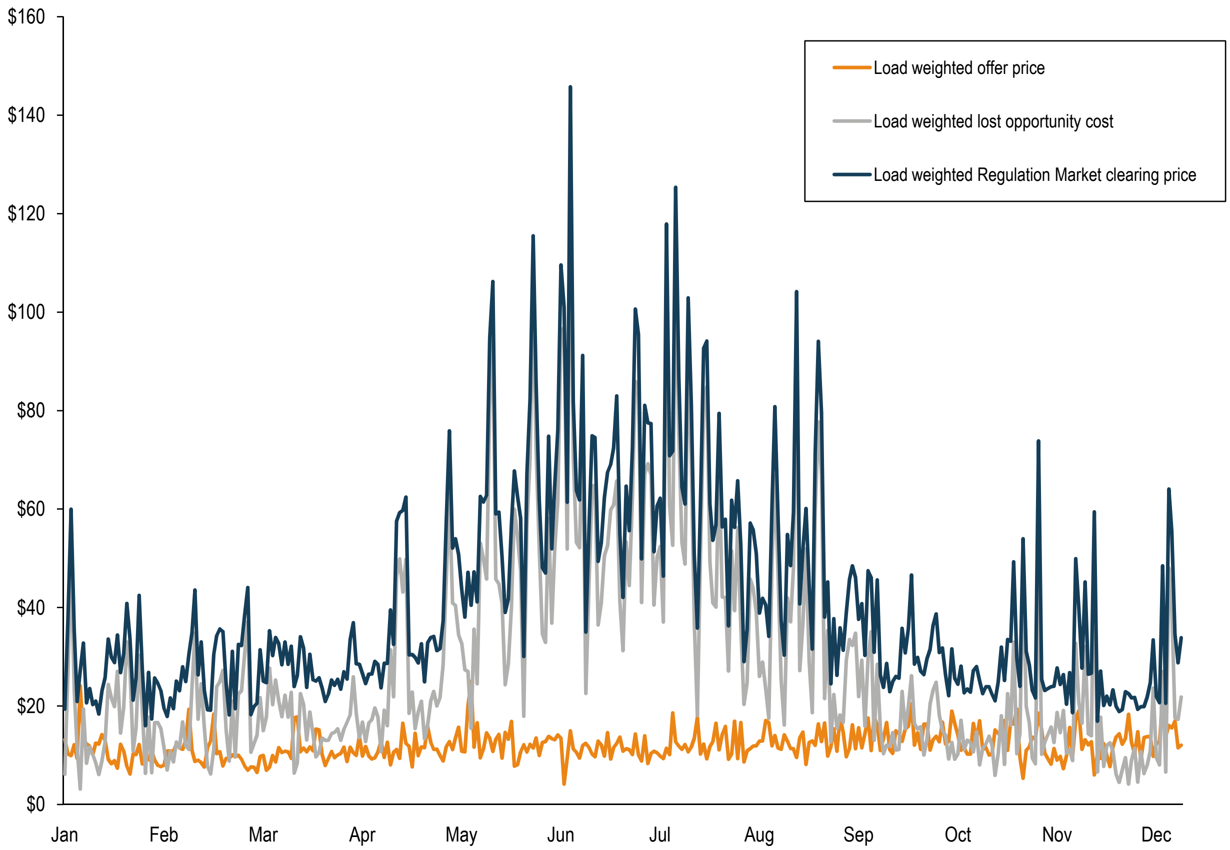
20 See PJM. "Manual 28: Operating Agreement, Accounting," Revision 41, Section 4, "Regulation Credits" (November 1, 2008), pp. 27-28. PJM uses estimated opportunity cost to clear the market and real-time opportunity cost to compensate generators that provide regulation and synchronized reserve. Real-time opportunity cost is calculated using real-time LMP.

21 The percent of hours in which the offer of the marginal unit exceeded marginal cost is slightly less than the percent of offers of marginal units exceeding marginal cost because there can be multiple marginal units in an hour.

22 PJM M-15, Cost Development Guidelines, Rev 9, January 23, 2009, Section 4, Fuel Cost Guidelines, Section 5, Operating and Maintenance Cost Guidelines, and Section 6, Start Cost Guidelines. Pgs. 11-34

units are paid RMCP times their assigned regulation MWh, a substantial portion of the RMCP is the LOC, based on forecast LMP calculated for the marginal unit during market clearing. This means that a substantial portion of the total cost of regulation is determined by LOC. As shown in Figure 6-2, more than half of the regulation price is the LOC of the marginal unit. The balance of the RMCP is the unit's regulation offer. The load weighted, average offer of the marginal unit for the PJM Regulation Market during 2008 was $11.94 per MWh. The load weighted, average LOC of the marginal unit for the PJM Regulation Market during 2008 was $30.59. In the PJM Regulation Market the marginal unit LOC averaged 72 percent of the RMCP.

Figure 6-2 PJM Regulation Market daily average market-clearing price, lost opportunity cost and offer price (Dollars per MWh): Calendar year 2008



On a shorter term basis, regulation prices follow daily and weekly patterns. The supply of regulation is most plentiful between 0600 and 2300 EPT, Monday through Friday.

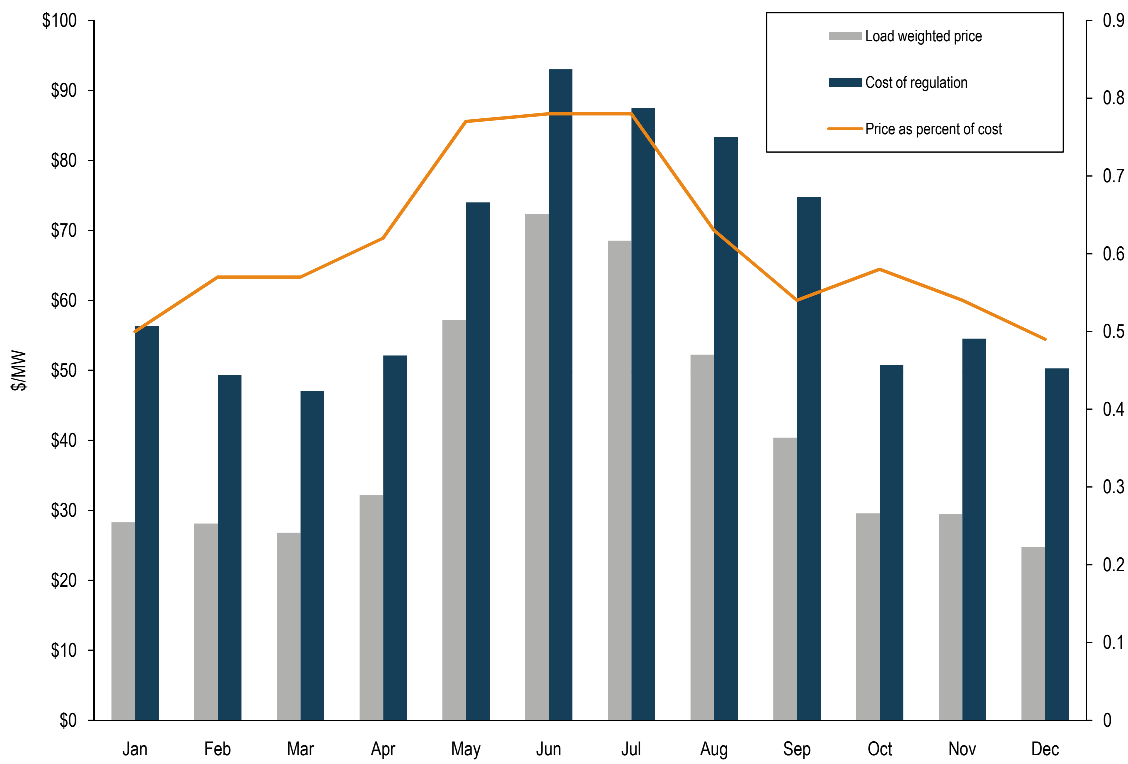
During weekends and North American Electric Reliability Council (NERC) holidays, and weekdays between the hour ending at 2300 until the hour ending at 0800 (i.e., the off-peak hours), fewer steam generators are running and available to regulate. At times, units must be kept running for regulation that are not economic for energy, resulting in an increase in the LOC portion of the clearing price. At other times, expensive combustion turbine generators must be started to meet regulation requirements. Although the regulation requirement is a function of reliability concerns, lower off-peak load allowed PJM to decrease the off-peak regulation requirement in August 2008, thus aligning demand with supply and moderating prices.

Figure 6-3 shows the level of demand for regulation by month in 2008 and the corresponding level of regulation price. The data show a correlation between price and demand. In 2008, the August reduction in the regulation requirement for off-peak hours resulted in a corresponding reduction in regulation demand and price.

Figure 6-3 Monthly average regulation demand (required) vs. price: Calendar year 2008

As with all ancillary services, the total cost of the service per MWh will exceed the price per MWh because some regulation is procured out of the market or because there are adjustments to unit specific LOC after the market clears. A well designed and efficient market will minimize this difference. Units which provide regulation are paid the higher of the RMCP or their offer plus their unit specific opportunity cost. The offer plus the unit specific opportunity cost may be higher than the RMCP for a number of reasons. If real time LMP is greater than the LMP forecast prior to the operating hour and included in the RMCP, unit specific opportunity costs will be higher than forecast. Such higher LMPs can be local, because of congestion, or more general, if system conditions change. Other reasons include unit redispatch because of constraints or unanticipated unit performance problems. When some units are paid more than the RMCP based on unit specific lost opportunity costs, the result is that PJM's regulation cost per MWh is higher than the RMCP. Figure 6-4 compares the regulation cost per MWh (price plus settled lost opportunity costs) with the regulation clearing price to show the difference between the price of regulation and the cost of regulation.

Figure 6-4 Monthly load weighted, average regulation cost and price: Calendar year 2008



Total scheduled regulation MWh, total regulation charges, regulation price and regulation cost are listed in Table 6-6.

Table 6-6 Total regulation charges: Calendar year 2008

Month	Scheduled Regulation MWh	Total Regulation Charges	Weighted Average Regulation Market Price ($/MWh)	Cost of Regulation ($/MWh)
Jan	739,736	$41,680,277	$28.29	$56.34
Feb	685,256	$33,792,512	$28.16	$49.31
Mar	659,679	$31,036,079	$26.76	$47.04
Apr	587,950	$30,640,949	$32.12	$52.11
May	593,392	$43,908,281	$57.43	$74.00
Jun	767,808	$71,423,112	$72.51	$93.03
Jul	857,979	$75,035,751	$69.41	$87.46
Aug	727,153	$60,569,059	$52.21	$83.30
Sep	622,563	$46,572,848	$40.38	$74.81
Oct	576,303	$30,251,416	$29.58	$52.49
Nov	598,079	$32,617,280	$29.52	$54.54
Dec	677,526	$34,066,767	$24.79	$50.28
Total	8,093,424	$521,485,646	$42.09	$64.43

For 2008, the load weighted, average regulation price was $42.09 per MWh. The average regulation cost was $64.43 per MWh. The difference between the Regulation Market price and the actual cost of regulation remained significant in 2008. The cost of regulation was 53 percent higher than the market price of regulation. The payment of a large portion of regulation charges on a unit specific basis rather than on the basis of a market clearing price remains a cause for concern as it results in a weakened market price signal to the providers of regulation.

Synchronized Reserve Market

Market Structure

In 2008, the PJM Synchronized Reserve Market structure remained unchanged following its restructuring in 2007. Reliability requirements for the RFC Synchronized Reserve Zone are set by the Reliability*First* Corporation. The Southern Region's Synchronized Reserve Market remains a separate market. It falls under the reliability requirements of SERC and is referred to as the Southern Synchronized Reserve Zone. Although the RFC Synchronized Reserve Market is one market, transmission constraints often limit the amount of Tier 1 synchronized reserve that can be made available in the PJM Mid-Atlantic subzone of the RFC. This subzone is defined as the RFC Synchronized Reserve Zone exclusive of the AP, AE, Dayton, Duquesne, and ComEd zones.[23] Therefore PJM's market must clear enough Tier 2 synchronized reserve in the Mid-Atlantic (Eastern) subzone of the RFC Synchronized Reserve Market to ensure that the Mid-Atlantic locational

23 PJM M-11, Scheduling Operations, Rev 37, November 24, 2008, pg. 44.

synchronized reserve requirement of 1,150 MW is met, after accounting for available Tier 1 supply. This results in a separate Mid-Atlantic subzone clearing price.

Supply

Synchronized reserve is an ancillary service defined as generation or curtailable load that is synchronized to the system and capable of producing output or shedding load within 10 minutes. Synchronized reserve can, at present, be provided by a number of resources, including steam units with available ramp, condensing hydroelectric units, condensing combustion turbines (CTs) and CTs running at minimum generation. Synchronized reserve can also be supplied by DSR resources subject to the limit that they provide no more than 25 percent of the total synchronized reserve requirement. Synchronized reserve DSR resources can be provided by behind the meter generation or by load reductions.

All of the resources that participate in the Synchronized Reserve Markets are categorized as Tier 2 synchronized reserve. Tier 1 resources are those resources that are online, following economic dispatch, and able to respond to a spinning event by ramping up from their present output. All resources operating on the PJM system are considered potential Tier 1 resources, except for those explicitly assigned to Tier 2 synchronized reserve. Tier 2 resources include units that are backed down to provide synchronized reserve capability, condensing units synchronized to the system and available to increase output and demand side resources.

Under Synchronized Reserve Market rules, Tier 1 resources are paid when they respond to an identified spinning event as an incentive to respond when needed.[24] Tier 1 synchronized reserve payments or credits are equal to the integrated increase in MW output above economic dispatch from each generator over the length of a spinning event, multiplied by the synchronized reserve energy premium less the hourly integrated LMP. The synchronized reserve energy premium is defined as the average of the five minute LMPs calculated during the spinning event plus $50 per MWh. All units called on to supply Tier 1 or Tier 2 synchronized reserve have their actual MW monitored. Tier 1 units are not penalized if their output fails to match their expected response as they are only compensated for their actual response.

Under Synchronized Reserve Market rules, Tier 2 synchronized reserve resources are paid to be available as synchronized reserve, regardless of whether the units are called upon to generate in response to a spinning event, and are subject to penalties if they do not provide synchronized reserve when called. The price for Tier 2 synchronized reserve is determined in a market for Tier 2 synchronized reserves. This market is termed the Synchronized Reserve Market. Several steps are necessary before the hourly Synchronized Reserve Market is cleared. Ninety minutes prior to the start of the hour, PJM estimates the amount of Tier 1 reserve available from every unit; 60 minutes prior to the start of the hour, self-scheduled Tier 2 units are identified. Thirty minutes prior to the hour, Tier 1 is estimated again. If synchronized reserve requirements are not met by Tier 1 and self-scheduled Tier 2 resources, then a Tier 2 clearing price is determined at least 30 minutes prior to the start of the hour. This Tier 2 price is equivalent to the merit-order price of the highest-priced, Tier 2 resource needed to meet the demand for synchronized reserve requirements, the marginal

24 See PJM. "Manual 11: Scheduling Operations," Revision 37 (November 24, 2008), p. 41.

unit, based on the simultaneous clearing of the Regulation Market and the Synchronized Reserve Market.[25]

The synchronized reserve offer price submitted for a unit can be no greater than the unit's incremental operating and maintenance cost plus a $7.50 per MWh margin.[26, 27] The market clearing price is comprised of the marginal unit's synchronized reserve offer price, the cost of energy use, the startup cost (if the unit is not running) and the unit's lost opportunity cost. LOC is calculated by PJM based on forecast LMPs and generation schedules from the unit dispatch system. LOC for demand-side resources is always zero. All units cleared in the Synchronized Reserve Markets are paid the higher of either the market-clearing price or the unit's synchronized reserve offer plus the unit specific LOC and the cost of energy use incurred.

The Tier 2 Synchronized Reserve Market in each of PJM's synchronized reserve areas is cleared on cost based offers because the structural conditions for competition do not exist. The market structure issue can be even more severe when the Synchronized Reserve Market becomes local because of transmission constraints.

For the RFC Synchronized Reserve Zone during 2008, the offered and eligible excess supply ratio was 2.01. Within the Mid-Atlantic Subzone of the RFC Synchronized Reserve Zone, the offered and eligible excess supply ratio was 1.41.[28] These excess supply ratios are determined using the administratively established requirement for synchronized reserve. Actual market demand for Tier 2 synchronized reserve is lower than the synchronized reserve requirement because a significant amount of Tier 1 synchronized reserve is usually available.

Demand

The market demand for Tier 2 synchronized reserve is determined by subtracting the amount of forecast Tier 1 synchronized reserve available from each synchronized reserve zone's synchronized reserve requirement for the period. Market demand is further reduced by subtracting the amount of self scheduled Tier 2 resources. The total synchronized reserve requirement is different for the two Synchronized Reserve Markets. The synchronized reserve requirement is determined at the discretion of PJM after careful review to ensure appropriate system reliability and to maintain compliance with applicable NERC and regional reliability organization requirements. RFC and Dominion reserve requirements are determined on at least an annual basis. Mid-Atlantic Subzone requirements are established on a seasonal basis, recognizing potential deliverability issues.[29]

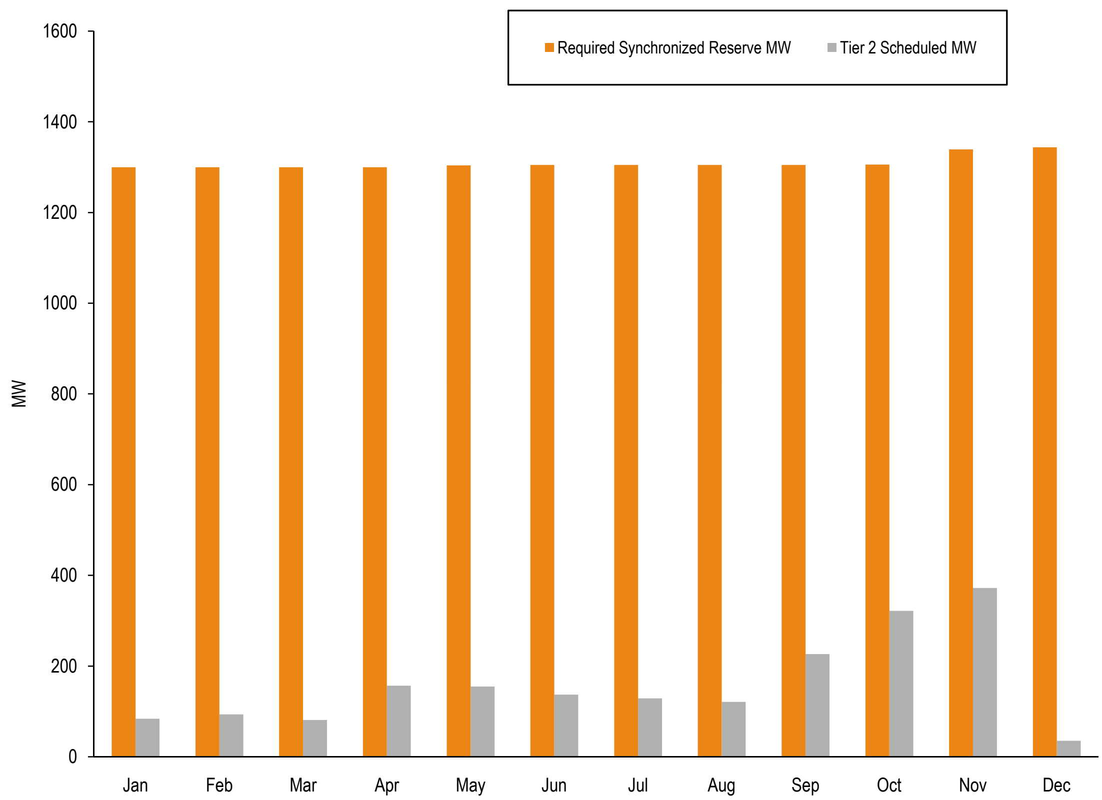
Currently the RFC synchronized reserve requirement is the greater of the Reliability*First* Corporation's imposed minimum requirement or the system's largest contingency. The actual synchronized reserve requirement for the RFC Zone for January through May 9, 2008 was 1,300 MW. From May 10, 2008 through December 31, 2008 the requirement was 1,305 MW.[30] Exceptions to this requirement can occur when grid maintenance or outages change the largest contingency.

25 Although it is unusual, a PJM dispatcher can deselect units which have been committed after the clearing price has been established. This only happens if real-time system conditions require dispatch of a spinning unit for constraint control, or problems with a generator or monitoring equipment are reported.
26 See PJM. "Manual 11: Scheduling Operations," Revision 37 (November 24, 2008), p. 43.
27 See PJM. "Manual 15: Cost Development Guidelines," Revision 8 (October 16, 2007), p. 34.
28 The Synchronized Reserve Market in the PJM Southern Region cleared in so few hours that related data for that market are not meaningful.
29 See PJM. "Manual 10: Pre-Scheduling Operations," Revision 23 (January 2, 2008), p. 17.
30 The reasons for this increase are not known.

Such a condition occurred on February 2 when the Synchronized Reserve requirement was set at 2,300 MW. For 2008, the average RFC Zone Tier 2 required was 1,310 MW.

Figure 6-5 shows the average monthly synchronized reserve required and the average monthly Tier 2 synchronized reserve MW scheduled during 2008 for the RFC Synchronized Reserve Market. Figure 6-5 and Figure 6-6 below show that the amount of Tier 2 synchronized reserve scheduled for the RFC Zone and the Mid-Atlantic Subzone increased in September, October and November and then decreased sharply in December.

Figure 6-5 RFC Synchronized Reserve Zone monthly average synchronized reserve required vs. Tier 2 scheduled MW: Calendar year 2008



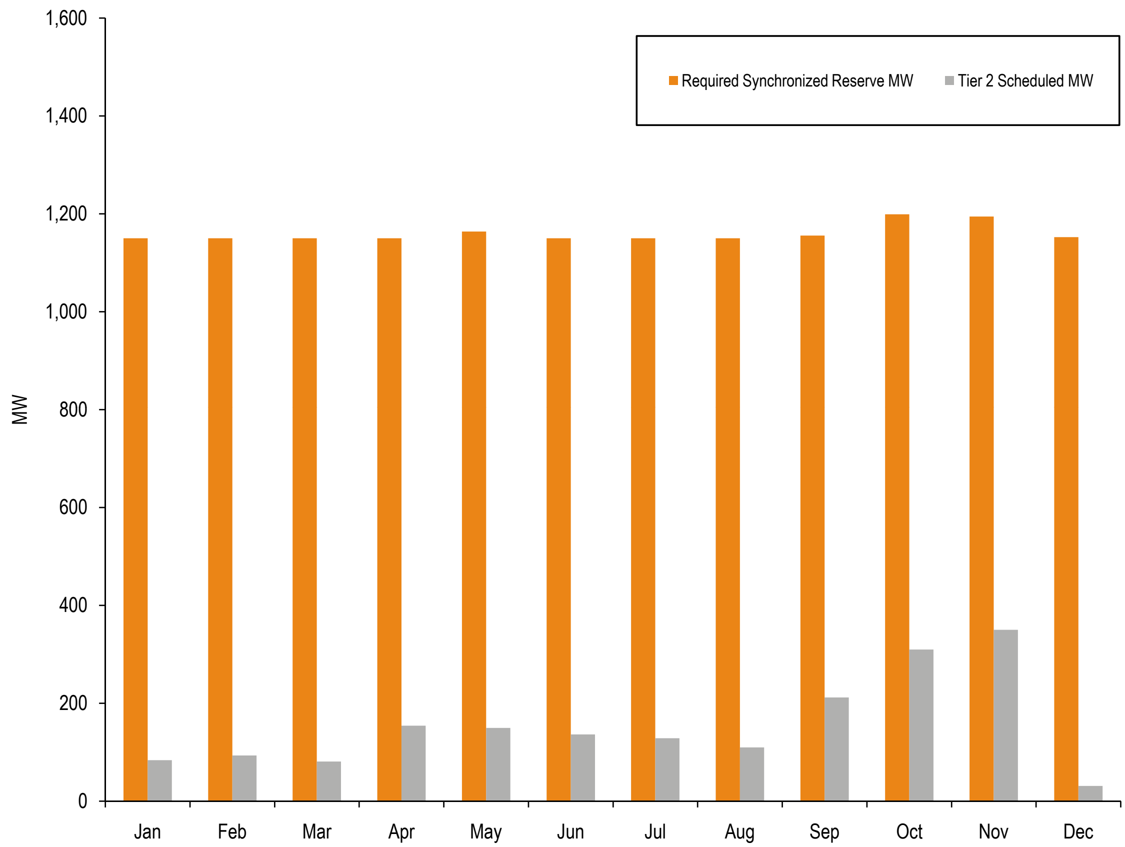
The RFC Synchronized Reserve Zone is large and some available Tier 1 must be physically located in the Mid-Atlantic Subzone as a result of transmission limits between the western and eastern portions of the zone. PJM calculates the transfer capability of these transmission facilities. The calculation of Mid-Atlantic Subzone Tier 1 includes what is available in the east plus the amount of Tier 1 synchronized reserve in the west that can be transferred into the east.[31]

As a whole, the RFC Synchronized Reserve Zone almost always has enough Tier 1 to cover its synchronized reserve requirement. Available Tier 1 in the western part of the RFC Synchronized

31 See PJM. "Manual 11: Scheduling Operations," Revision 37 (October 24, 2008,), p. 48.

Reserve Zone generally exceeds the total synchronized reserve requirement in the west. In 2008, the RFC Synchronized Reserve Zone cleared a Tier 2 Synchronized Reserve Market in 5 percent of all hours. This is not the case in the Mid-Atlantic Subzone. As a result, there is frequently a Tier 2 synchronized reserve requirement only in the Mid-Atlantic Subzone and a separate clearing price for the Mid-Atlantic Subzone. The Mid-Atlantic Subzone of the RFC Synchronized Reserve Zone cleared a separate Tier 2 market in 62 percent of all hours. Figure 6-6 compares the required synchronized reserve MW to the scheduled Tier 2 MW for the Mid-Atlantic Subzone only.

Figure 6-6 RFC Synchronized Reserve Zone, Mid-Atlantic Subzone average hourly synchronized reserve required vs. Tier 2 scheduled: Calendar year 2008



The actual synchronized reserve requirement for the Mid-Atlantic Subzone for February through December 2008 was usually 1,150 MW but there were several days when temporary grid conditions created a double contingency which increased the requirements. Required synchronized reserve was as high as 2,300 MW on February 2, 2008. Throughout all of 2008, the average synchronized reserve required MW in the Mid-Atlantic Subzone was 1,160 MW. The difference between the level of required synchronized reserve and the level of Tier 2 synchronized reserve scheduled is the amount of Tier 1 synchronized reserve available on the system.

A comparison of Figure 6-5 and Figure 6-6 illustrates that 98.9 percent of Tier 2 Synchronized Reserve Market MW are Mid-Atlantic Subzone, Synchronized Reserve Market MW.

The Southern Synchronized Reserve Zone is part of the Virginia and Carolinas Area (VACAR) subregion of SERC. VACAR specifies that available, 15 minute quick start reserve can be subtracted from Dominion's share of the largest contingency to determine synchronized reserve requirements.[32] The amount of 15 minute quick start reserve available in VACAR is sufficient to make Tier 2 synchronized reserve demand zero for most hours. The actual hourly Southern Synchronized Reserve Zone's synchronized reserve requirement was usually zero because Dominion's share of the largest contingency within VACAR was offset by its quick start capability. On average, the hourly synchronized reserve requirement in Dominion was 1.5 MW.

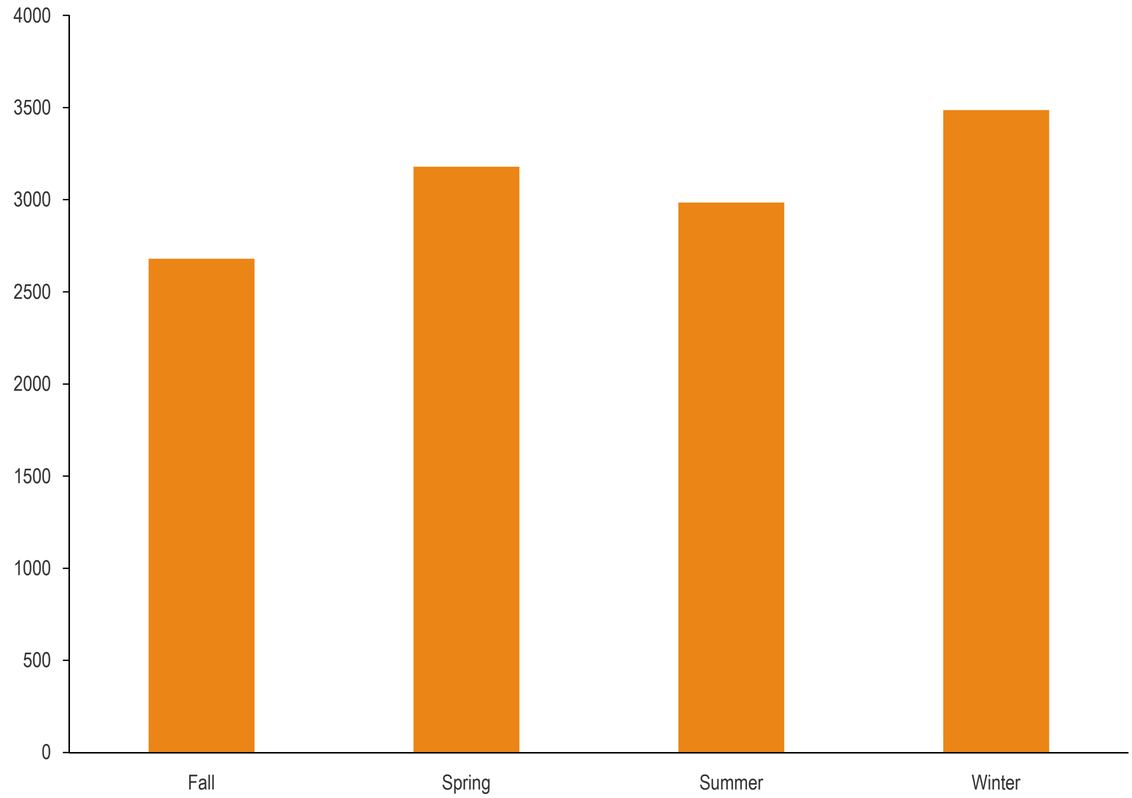
Market Concentration

The Tier 2 Synchronized Reserve Market is the only Synchronized Reserve Market cleared by PJM. Although the RFC Tier 2 Synchronized Reserve Market was less concentrated in 2008 than it had been in 2007, the 2008 RFC Synchronized Reserve Market remains highly concentrated and dominated by a relatively small number of companies. Concentration levels have been reduced as a result of the increased participation of demand-side response in the synchronized reserve market.

The HHI for the Mid-Atlantic Subzone of the 2008 RFC Synchronized Reserve Market was 3106, which is defined as highly concentrated. (See Figure 6-7 which also provides seasonal details.)

32 See PJM. "Manual 11: Scheduling Operations," Revision 37 (November 24, 2008), p. 72.

Figure 6-7 Cleared Mid-Atlantic Subzone RFC Tier 2 Synchronized Reserve Market seasonal HHI: Calendar year 2008



The largest hourly market share was 100 percent and 52 percent of all hours had a maximum market share greater than or equal to 40 percent. In slightly less than one percent of Mid-Atlantic Subzone hours during which a market was cleared between January and December 2008, a single company had 100 percent of the market share. The highest annual average market share for a single company for all hours in which it had any market share, was 33 percent. In other words, a single company sold 33 percent of synchronized reserves on average for all hours in which it had market share over the entire year. (See Table 6-7.)

Table 6-7 The Mid-Atlantic Subzone of the PJM RFC Tier 2 Synchronized Reserve Market's cleared market shares: Calendar year 2008

Company Market Share Rank	Cleared Synchronized Reserve: All Units
1	33%
2	32%
3	30%
4	30%
5	29%

The pivotal supplier metric provides an analytical approach to the issue of excess supply.[33] In 2008, 96 percent of hours in the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market failed the three pivotal supplier test. One company was pivotal in 64 percent of all pivotal hours, a second company was pivotal in 44 percent of all pivotal hours, and a third company was pivotal in 43 percent of all pivotal hours. These results indicate that the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market, the only synchronized reserve market that clears on a regular basis, is not structurally competitive.

Market Conduct

Offers

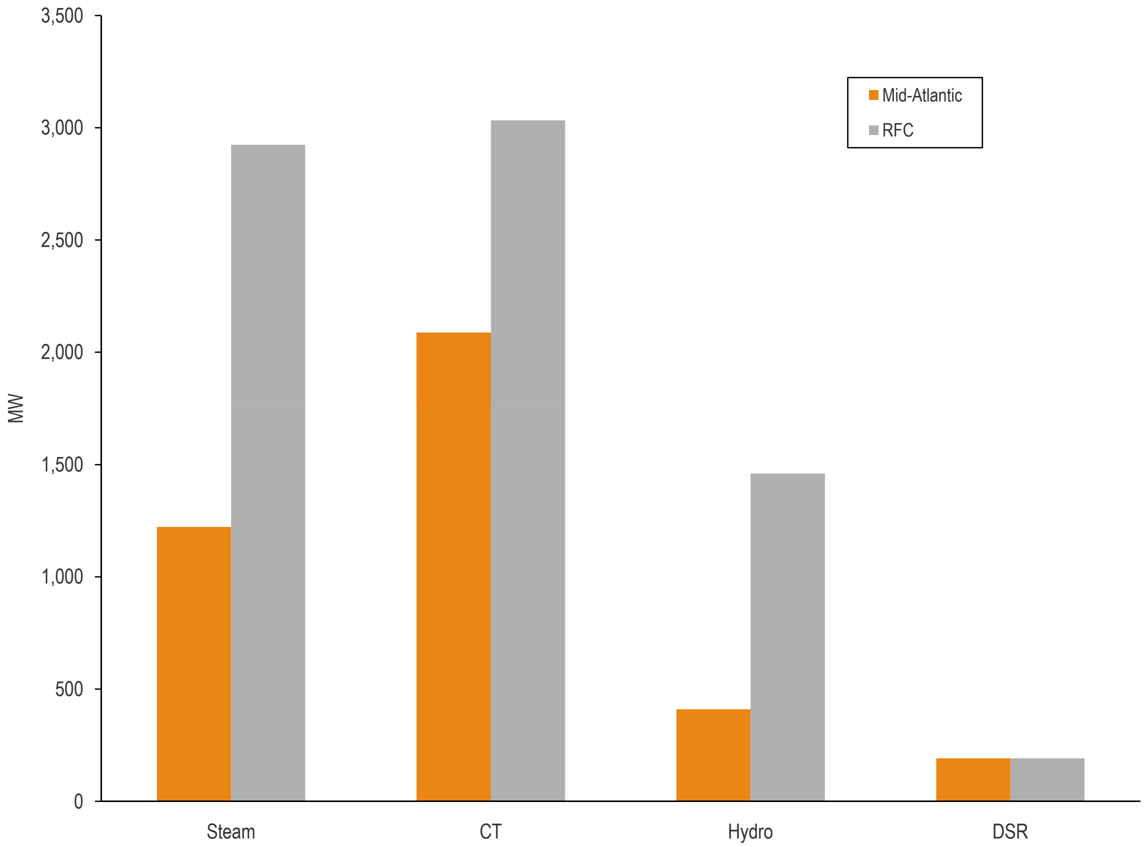
Figure 6-8 shows the daily average hourly offered Tier 2 synchronized reserve MW. For steam units, offered MW are eligible only if the offering unit is running. For that reason, the eligible offer volume shows weekly variability based on off-peak/on-peak operating cycles as well as seasonal variability.

Figure 6-8 Tier 2 synchronized reserve average hourly offer volume (MW): Calendar year 2008

33 See the *2008 State of the Market Report*, Volume II, Appendix L, "Three Pivotal Supplier Test."

Synchronized reserve is offered by steam, CT, hydroelectric and DSR resources. Figure 6-9 shows average offer MW volume by market and unit type.

Figure 6-9 Average daily Tier 2 synchronized reserve offer by unit type (MW): Calendar year 2008



The MW contribution of DSR resources to the Synchronized Reserve Market remained significant in 2008. The significance of DSR in the Synchronized Reserve Markets is greater than its eligible offer MW as illustrated in Figure 6-9. In 2008, DSR accounted for all cleared Tier 2 synchronized reserves in 27 percent of hours when a synchronized reserve market was cleared. In the hours when all supply was DSR, the unweighted average SRMCP was $2.58. The unweighted average SRMCP for all cleared hours was $8.49. As defined by PJM, demand-side resources may at times be generation that is behind the meter.

Market Performance

Price

Figure 6-10 shows the relationship among required Tier 2 synchronized reserve, Synchronized Reserve Market clearing price, and percent of cleared synchronized reserve satisfied by DSR in the Eastern subzone of the PJM Synchronized Reserve Market. This figure shows both that the synchronized reserve clearing price tends to increase with demand and that DSR satisfies a large percentage of Tier 2 synchronized reserve when the demand is low.

Figure 6-10 Required Tier 2 synchronized reserve, synchronized reserve market clearing price, and DSR percent of Tier 2

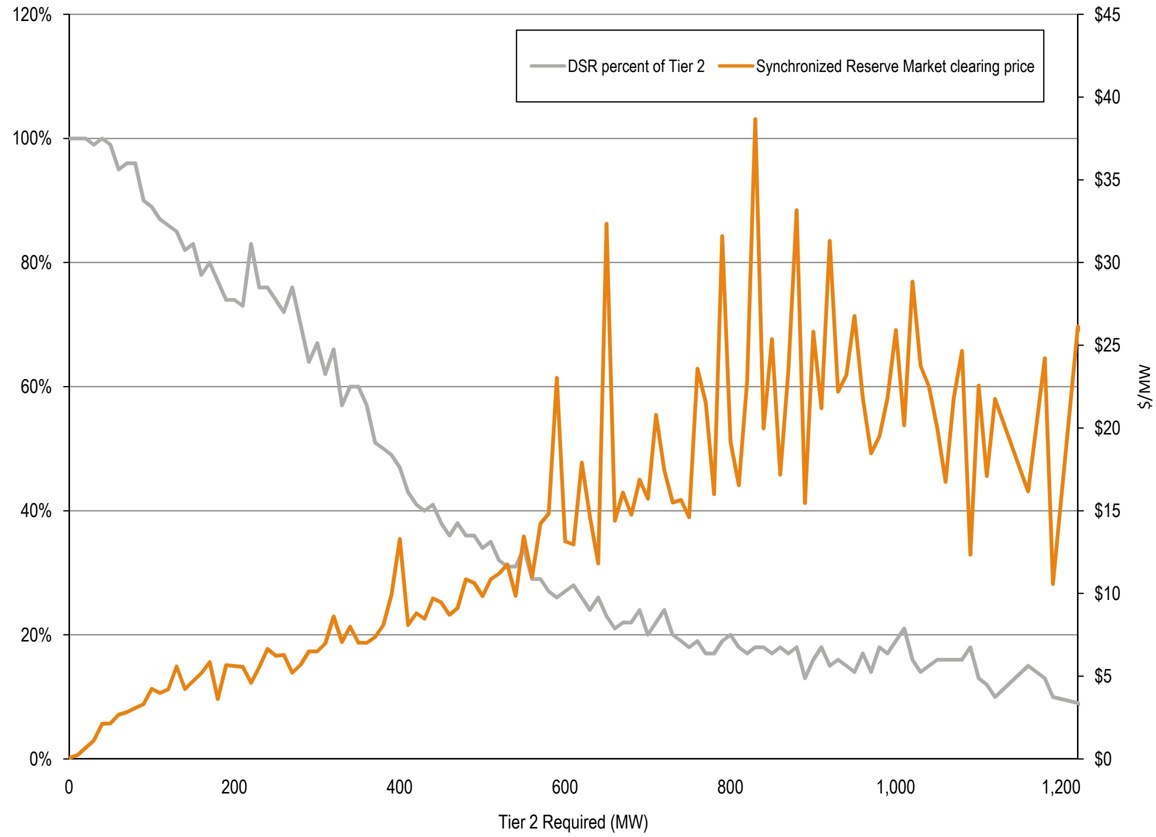


Figure 6-14 shows the load weighted, average Tier 2 price and the cost per MW associated with meeting PJM demand for synchronized reserve. The price of Tier 2 synchronized reserve is called the Synchronized Reserve Market-clearing price (SRMCP). Resources which provide synchronized reserve are paid the higher of the SRMCP or their offer plus their unit specific LOC. The offer plus the unit specific LOC may exceed the SRMCP for a number of reasons. If real time LMP is greater than the LMP forecast prior to the operating hour and included in the SRMCP, unit specific LOC will be higher than forecast. Such higher LMPs can be local because of congestion or more general if system conditions change. The additional costs of noneconomic dispatch are added to the total cost of synchronized reserve. When some units are paid the value of their offer plus their unit specific LOC, the result is that PJM's synchronized reserve cost per MWh is higher than the SRMCP.

The RFC Synchronized Reserve Market cleared as a single market 5 percent of all hours in 2008 with a load weighted average $4.94 clearing price. The load weighted, average price for synchronized reserve in the PJM Mid-Atlantic subzone of the RFC Synchronized Reserve Market in 2008 was $10.65 while the corresponding cost of synchronized reserve was $16.43.

Price and Cost

In 2008 PJM continued to rely on non-economic, out of market Tier 2 resources added to the resources procured in the synchronized reserve market. PJM dispatch procured additional Tier 2 reserves to cover anticipated operational needs. This added Tier 2 MW added to the cost of Tier 2 synchronized reserve and has been a significant contributor to total synchronized reserve costs. To improve the accuracy of the forecast Tier 1, PJM added a second Tier 1 estimate performed 30 minutes prior to the operating hour in September. This change appears to have had no impact on Tier 2 MW added after market clearing or on improving the forecasting the amount of Tier 1 available during a spinning event.

In December, a significant increase in the amount of estimated Tier 1 reduced the amount of Tier 2 needed to meet the required synchronized reserve. The increase in the amount of estimated Tier 1 appears to have been the result of a mistake in identifying available Tier 1 resources prior to December. The relationship between Tier 2 required and Tier 1 estimated is shown in Figure 6-11. When Tier 1 estimated increased from a daily average of 370 MW to 1,132 MW on December 1, 2008, the Tier 2 synchronized reserve market dropped from a November average of 350 MW to a December average of 31 MW.

The increase in Tier 1 resources did not reduce the amount of Tier 2 synchronized reserve added to the synchronized reserve market after market clearing. In December, the amount of Tier 2 cleared fell substantially, while the proportion of synchronized reserve added out of market increased significantly. Tier 2 MW added after the market cleared accounted for 44 percent of total Mid-Atlantic subzone synchronized reserve in 2008 and 80 percent in the month of December. Such synchronized reserve MW are not part of the market clearing process so they do not affect the price of synchronized reserve, but they do increase the amount of synchronized reserve purchased for which load-serving entities must pay. (See Figure 6-13.)

Figure 6-11 RFC Synchronized Reserve Zone, Mid-Atlantic Subzone daily average hourly synchronized reserve required, Tier 2 MW scheduled, and Tier 1 MW estimated

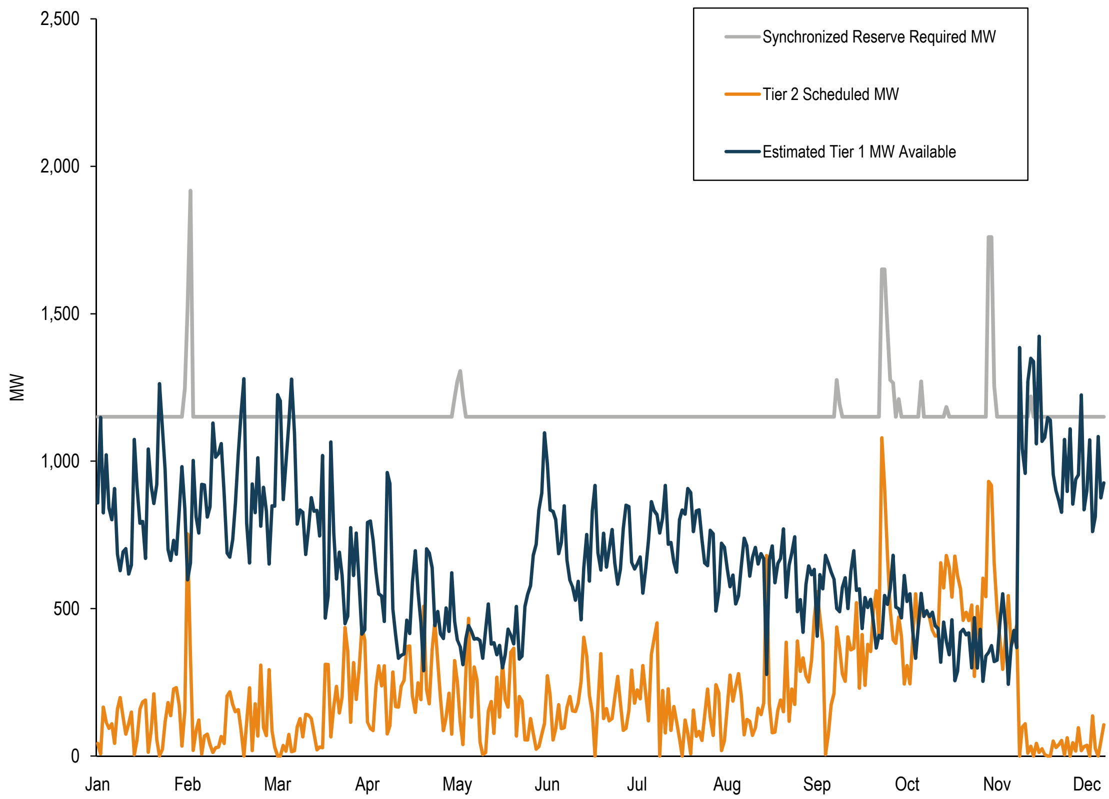
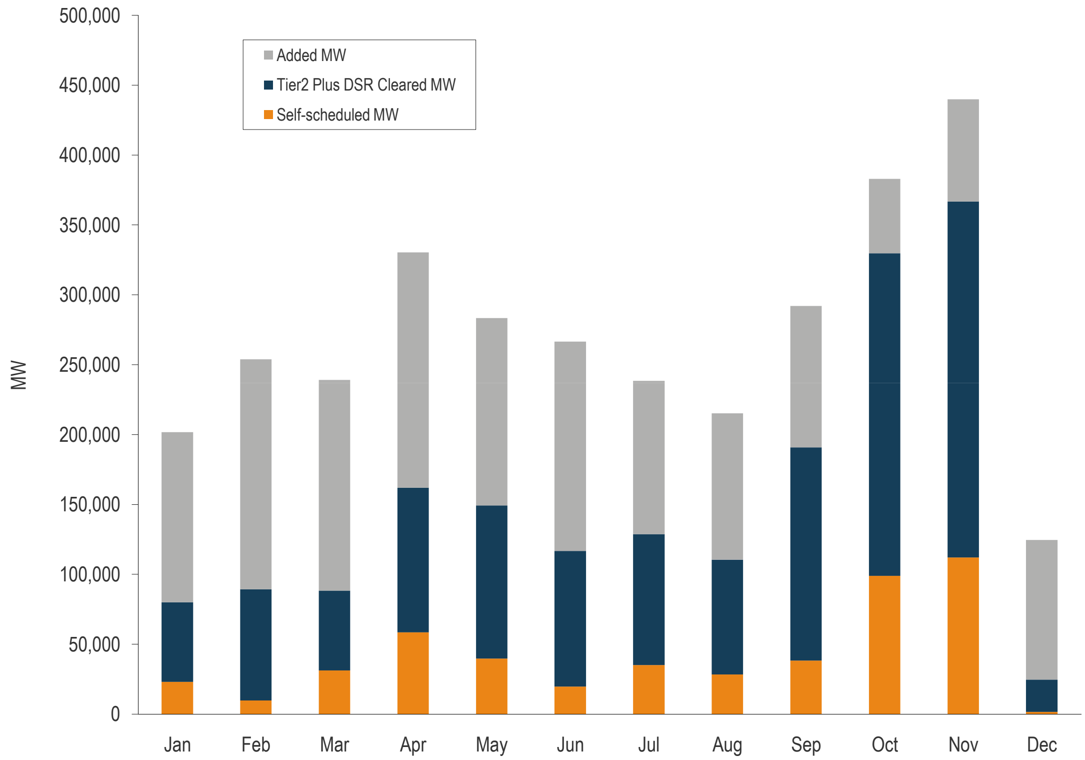


Figure 6-12 Tier 2 synchronized reserve purchases by month for the Mid-Atlantic subzone DSR



The out of market purchases indicate that the Synchronized Reserve Market is not functioning to adequately coordinate supply and demand. (Figure 6-13) The addition of synchronized reserve MW to the Synchronized Reserve Market on an out of market basis means that the clearing price is below the efficient level for the defined market. It is clear that there is a difference in the calculation of the need for Tier 2 synchronized reserves between the market solution and the operators. The reason remains under investigation.

The difference between the Tier 2 Synchronized Reserve Market price and the cost for Tier 2 synchronized reserve in 2008 was approximately the same as it had been in 2007 (Figure 6-14). The difference in the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market for 2008 between the monthly load weighted, average price of Tier 2 synchronized reserve and cost of Tier 2 synchronized reserve was $5.82. The cost was 55 percent higher than the price. In 2007 the cost had been 31 percent higher than the price.

Figure 6-13 Impact of Tier 2 synchronized reserve added MW to the RFC Synchronized Reserve Zone, Mid-Atlantic subzone: Calendar year 2008

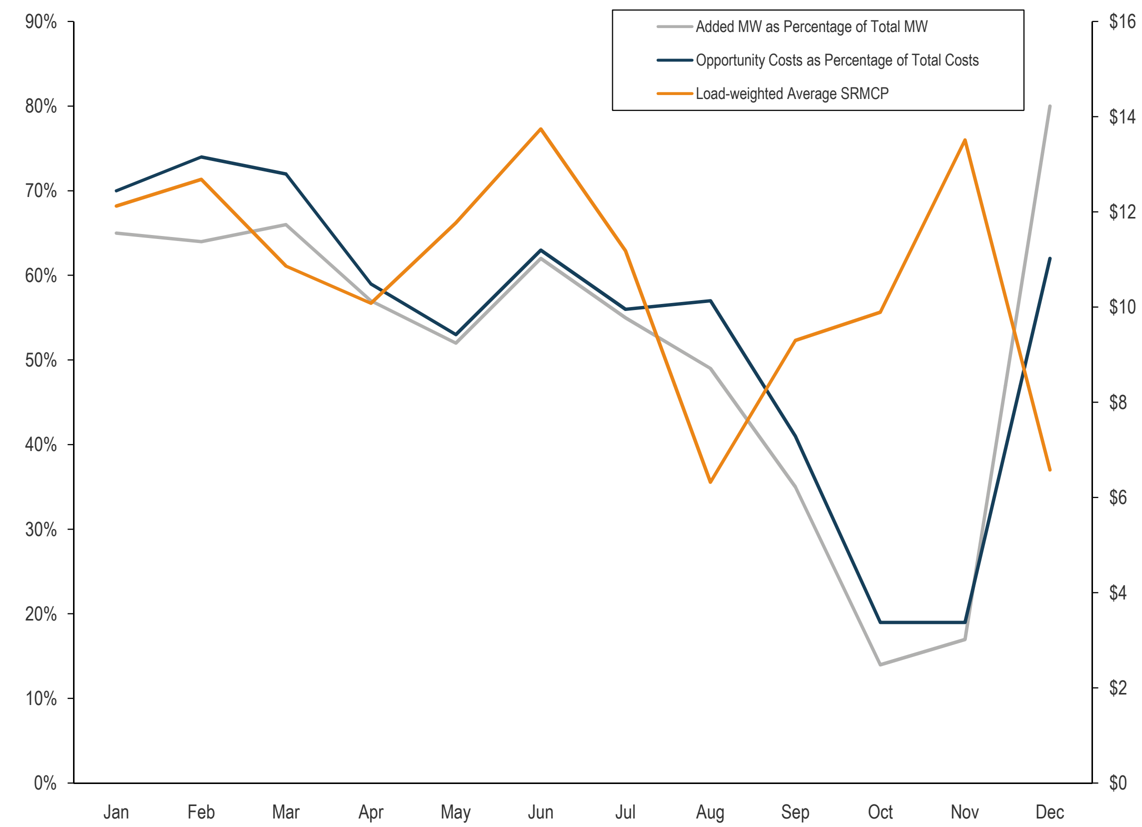
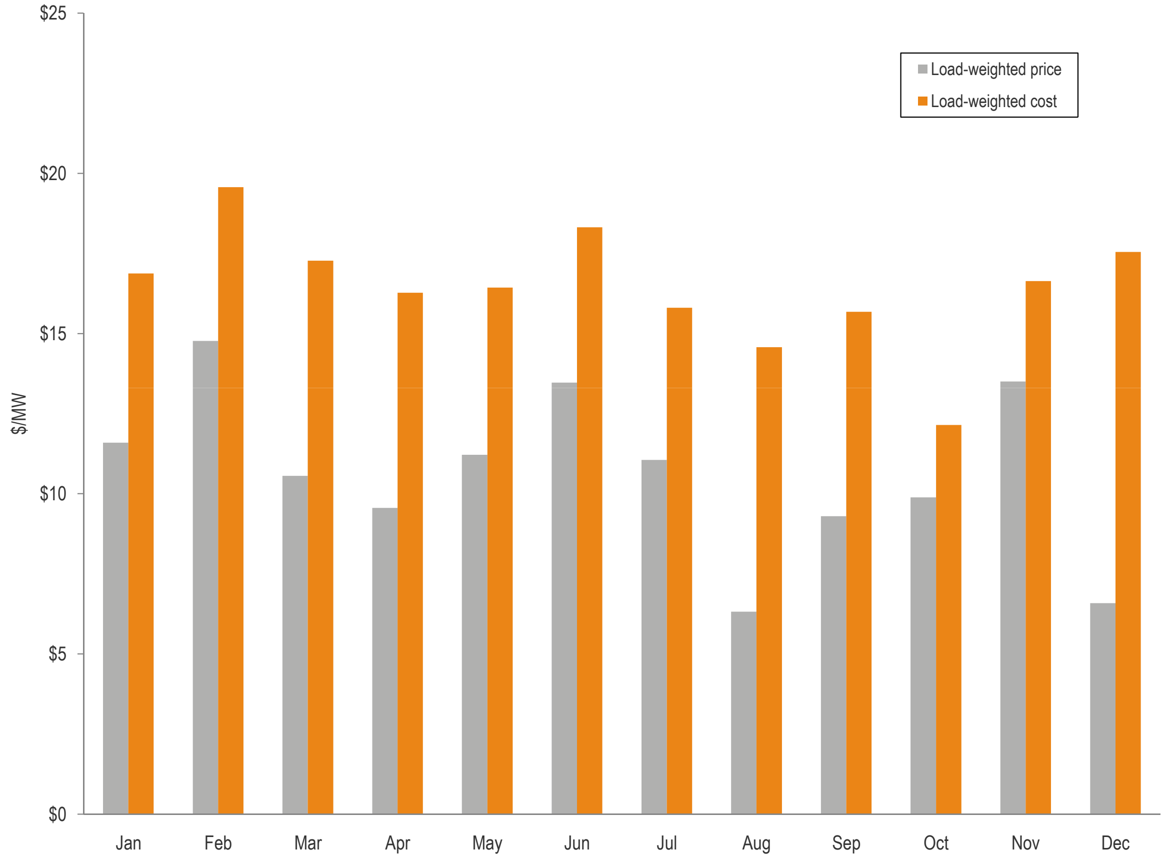


Figure 6-14 Comparison of RFC Tier 2 synchronized reserve price and cost (Dollars per MW): Calendar year 2008



Market Solution and Actual Dispatch of Ancillary Services

The actual dispatch of ancillary services can and does differ from the market solution, in many cases, as a result of legitimate reliability concerns. The result is usually that total costs per MWh (credits/MWh) are higher than the clearing price (RMCP). The MMU analyzes this cost/price differential and reports the cost and price.

The market solution software (SPREGO) optimizes regulation and spinning using a theoretical unit dispatch and estimated Tier 1 synchronized reserve based on forecast load. The MMU attempts to document and categorize deviations from market solutions although there tends to be insufficient PJM documentation. Dispatchers can deselect a unit from regulation, Tier 1 or Tier 2 synchronized reserve, or unit dispatch prior to running the market solution. This is the equivalent of imposing a constraint on the market solution. The MMU recommends that all unit deselection reasons be published in PJM's M-11 Scheduling Operations Manual. The MMU recommends that dispatchers classify the reasons for unit deselection and document all unit deselections.

DSR

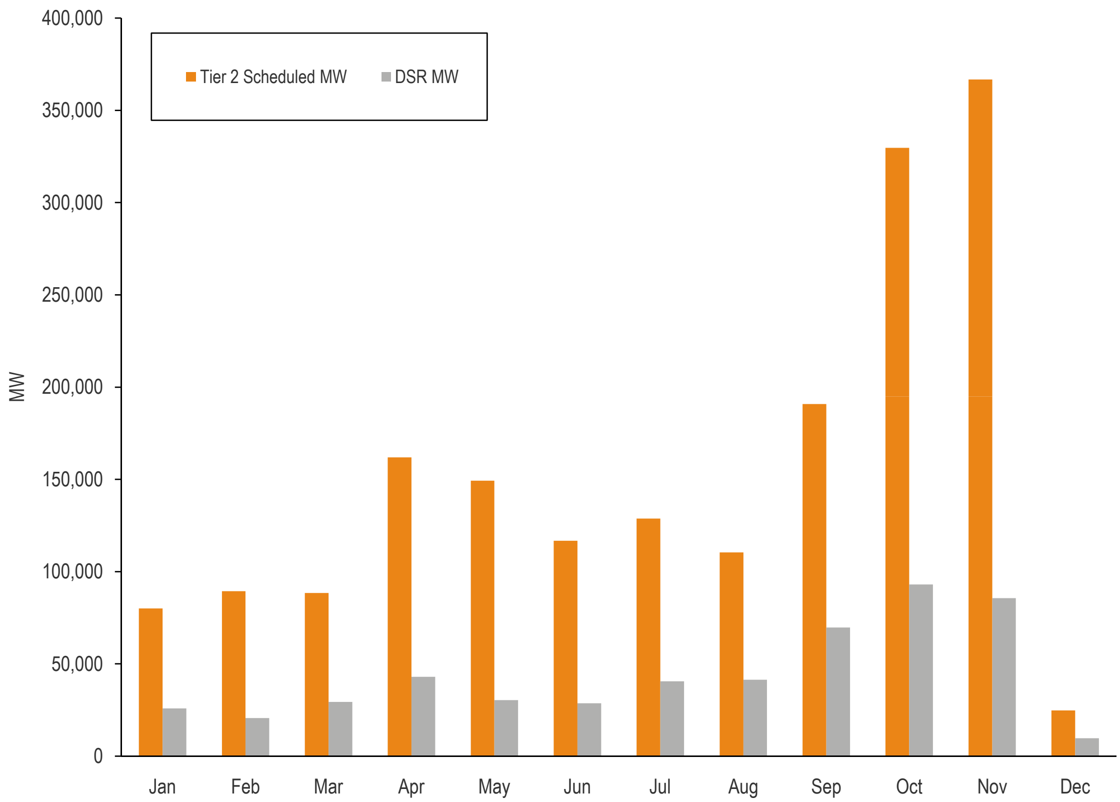
Demand-side resources began participating in the Synchronized Reserve Markets in August 2006. DSR continues to have a significant impact on the Synchronized Reserve Market. In 32 percent of hours where a synchronized reserve market was cleared in the Mid-Atlantic subzone of the RFC (see Table 6-8), all cleared synchronized reserve was DSR synchronized reserve. The clearing price for those hours was significantly lower than the average clearing price overall.

Table 6-8 Average SRMCP when all cleared synchronized reserve is DSR, average SRMCP, and percent of all cleared hours that all cleared synchronized reserve is DSR

Month	Average SRMCP when all cleared synchronized reserve is DSR	Average SRMCP	Percent of cleared hours all synchronized reserve is DSR
Jan	$2.65	$7.09	42%
Feb	$4.03	$7.87	41%
Mar	$3.89	$7.28	45%
Apr	$3.06	$7.33	28%
May	$2.42	$7.73	31%
Jun	$1.91	$9.30	26%
Jul	$1.73	$7.17	35%
Aug	$2.06	$3.47	41%
Sep	$2.48	$6.77	28%
Oct	$2.26	$8.03	17%
Nov	$2.30	$10.71	11%
Dec	$1.17	$2.09	36%

Figure 6-15 shows total monthly synchronized reserve scheduled MW and cleared MW for DSR synchronized reserve. Participation of demand response in the synchronized reserve market remained strong. Not only did more participants offer DSR, but demand response was significantly less expensive than other forms of synchronized reserve. The reason for the lower price of demand resources is twofold. Demand resources typically offer at a lower price, and demand resources do not have lost opportunity costs added to their offer in market clearing. In 32 percent of hours during 2008 in which a Tier 2 Synchronized Reserve Market was cleared for the Mid-Atlantic Subzone, all synchronized reserve was provided by DSR.

Figure 6-15 PJM RFC Zone Tier 2 synchronized reserve scheduled MW: Calendar year 2008



Availability

A synchronized reserve deficit occurs when the combination of Tier 1 and Tier 2 synchronized reserve is not adequate to meet the synchronized reserve requirement. Neither PJM Synchronized Reserve Market experienced deficits during 2008.

Day Ahead Scheduling Reserve (DASR)

PJM has a requirement to procure supplemental reserves to ensure that differences in forecasted loads and forced generator outages will not have a negative impact on grid reliability.[34] Prior to June 1, 2008, PJM obtained supplemental reserves from several sources including available unused capacity of generating units that had been dispatched for energy, available capacity of units not dispatched for energy but capable of coming online in 30 minutes and dispatch of additional units for the purpose of making supplemental reserve available.

34 PJM uses the terms "supplemental operating reserves" and "scheduling operating reserves" interchangeably.

On June 1, 2008 PJM introduced the Day-Ahead Scheduling Reserve Market (DASR), as required by the settlement in the RPM case.[35] The purpose of this market is to satisfy supplemental (30-minute) reserve requirements with a market-based mechanism that allows generation resources to offer their reserve energy at a price and compensates cleared supply at the market clearing price. The DASR 30-minute reserve requirements are determined by the reliability region.[36] In the Reliability*First* (RFC) region, reserve requirements are calculated based on historical under forecasted load rates and generator forced outage rates. For 2008 the load forecast error component of this calculation was 2.10 percent of peak load forecast. The forced outage rate component of the calculation is based on a three-year rolling average of the forced outage rate that occurs from 1800 of the scheduling day through the operating day at 2000. For 2008 the forced outage component of the Day-Ahead Scheduling Reserve was 4.64 percent. For 2008 the Day-Ahead Scheduling Reserve for RFC areas of PJM was 6.75 percent times Peak Load Forecast for RFC. Dominion Day-Ahead Scheduling Reserve is based on its share of the VACAR Reserve Sharing agreement and is set annually. In 2008 VACAR scheduling reserve was set at 423 MW. The RFC and Dominion Day-Ahead Scheduling Reserve Requirements are added together to form a single RTO DASR Requirement which is obtained via the DASR Market. The requirement is applicable for all hours of the operating day.

If the DASR Market does not result in procuring adequate scheduling reserves, PJM is required to schedule additional operating reserves.

DASR is an offer-based market that clears for all hours of the day at 1600 EPT day-ahead. DASR Market clearing is simultaneous and co-optimized with the Day-Ahead Energy Market.

All generating resources capable of increasing their output in 30 minutes are eligible to provide DASR. Load response resources which are registered in PJM's Economic Load Response and are dispatchable by PJM are also eligible to provide DASR. All DASR offers must be submitted by 1200 EPT day-ahead. There is a must offer requirement in the DASR Market, but any offer price will satisfy the requirement. Resources which are eligible for DASR but which have not offered into the market will have their offers set to $0.00.

In the first two months of DASR operation there were many units without offers, several units with offers high enough to ensure that they would not clear and some software problems. Since that initial period, the DASR Market has been relatively stable and characterized by low prices.

35 See PJM Interconnection, L.L.C., 117 FERC ¶ 61,331 (2006).

36 PJM Manual 13, Emergency Requirements, Rev 35, 11/07/2008; pp 11-12.

Table 6-9 2008 PJM, Day-Ahead Scheduling Reserve Market MW and clearing prices

Month	Average Required MW	Average Cleared MW	Minimum Clearing Price	Maximum Clearing Price	Load Weighted Price	Total Deficit MW	Total Load Reduction MW
Jun	1,622	1,622	$0.00	$7.80	$0.91	0	0
Jul	4,484	4,484	$0.00	$2.00	$0.55	0	0
Aug	6,044	6,044	$0.23	$1.50	$0.36	0	0
Sep	5,162	5,162	$0.14	$1.00	$0.23	0	0
Oct	4,825	4,825	$0.00	$0.22	$0.10	0	0
Nov	5,194	5,194	$0.00	$0.22	$0.09	0	386
Dec	5,633	5,633	$0.00	$0.75	$0.09	0	1,042

For June 2008 through December 2008, the load weighted price of DASR was $0.26. As can be seen from Table 6-9, DASR prices declined in the last three months of 2008. DSR began to offer and clear the market in November and became significant in December.

The DASR Market in 2008 had three pivotal suppliers in a monthly average of 45 percent of all hours. Although the DASR Market was structurally non competitive for a substantial portion of all hours, the proportion of hours in which there were three pivotal suppliers declined in November and December (see Table 6-10).

Table 6-10 2008 PJM, Day-Ahead Scheduling Reserve Market pivotal supplier results

Month	Hours With Three Pivotal Suppliers
Jun	31%
Jul	38%
Aug	54%
Sep	80%
Oct	65%
Nov	23%
Dec	23%

In December, about 5.8 percent of all units engaged in economic withholding from the DASR Market by providing high offers. Conversely, 48 percent of units had offers of $0.00, either by choice or by default.

The fact that there is substantial structural market power in the DASR Market, together with the fact that the clearing prices in the DASR Market reflected a competitive result, suggests that market participants have the ability to exercise market power in this market but have not yet done so in a way that has affected market clearing prices.

While the MMU was represented at PJM stakeholder meetings during which the DASR Market was discussed, PJM did not request the assessment of the MMU as to whether the market would be expected to be structurally competitive or whether market power mitigation rules should be built into the market design. PJM has not implemented any form of market power mitigation in this market.

The MMU concludes that the DASR Market is not structurally competitive, based on the results in 2008. The MMU recommends that the DASR Market rules be modified to incorporate the application of the three pivotal supplier test. The MMU also concludes that the DASR Market results were competitive in 2008.

Black Start Service

PJM and its transmission owners must provide for sufficient and appropriately located resources that are capable of providing black start service in the PJM region. To accomplish this, transmission owners prepare system restoration plans that identify critical resources for reenergizing the grid following a possible blackout. Individual transmission owners, with PJM, identify the black start units included in each transmission owner's system restoration plan. PJM ensures the availability of black start by charging transmission customers according to their zonal load ratio share and compensating black start unit owners according to their revenue requirements (see Table 6-11 below). PJM defines a minimum critical black start for each transmission zone.[37]

Black start service is necessary to help ensure the reliable restoration of the grid following a black out. Black start service is the ability of a generating unit to start without an outside electrical supply or the demonstrated ability of a generating unit with a high operating factor to automatically remain operating at reduced levels when disconnected from the grid.[38]

Individual transmission owners, with PJM, identify the black start units included in each transmission owner's restoration plan. PJM defines required black start capability zonally and ensures the availability of black start by charging transmission customers according to their zonal load ratio share and compensating black start unit owners according to their revenue requirements (see Table 6-11). PJM defines a minimum critical black start for each transmission zone.[39]

37 PJM Manual 36, System Restoration, Rev 9, June 30, 2008, pgs. 51-52.
38 PJM Tariff, Second Revised Sheet No. 33.01, March 1, 2007.
39 PJM Manual 36, System Restoration, Rev 9, June 30, 2008, pgs. 51-52.

Table 6-11 Black Start yearly zonal charges for network transmission use

Zone	Network Charges
AECO	$413,077
AEP	$722,265
AP	$120,933
BGE	$473,503
ComEd	$7,771,183
DAY	$143,645
DLCO	$26,209
DPL	$362,409
JCPL	$428,936
Met-Ed	$398,811
PECO	$695,457
PENELEC	$325,395
Pepco	$211,985
PPL	$131,513
PSEG	$921,219

Schedule 6A of the PJM OATT makes available formula rates for units identified as “critical” in system restoration plans to collect their costs and authorizes PJM to perform billing and settlement of these costs (including costs collected pursuant to separately filed and eligible FERC tariffs). Schedule 6A was originally implemented in a manner most suited to the needs of existing older units that were equipped to provide black start service. Because the investment in the equipment needed to provide black start service by these units was made some time ago, the purpose of Schedule 6A primarily was to provide a level of compensation sufficient to encourage the owners of identified critical resources to continue providing the service.[40] These provisions established a rolling two-year commitment, appropriate for older units whose remaining useful life was uncertain.

In 2003, PJM, working with American Electric Power Service Corporation (“AEP”), determined that new black start capability was needed at a certain location on the AEP system, partly as a result of the retirement of a legacy black start service provider. PJM issued a request for proposal, and received only offers from suppliers who would need to install new equipment in order to provide the service. PJM selected from the few potentially viable projects, Constellation’s offer to provide black start service from its Big Sandy Peaker Plant (“Big Sandy”). Big Sandy required approximately $667,000 to install a 750 kW diesel generator and associated controls. Constellation deemed the recovery provisions included in Schedule 6A inadequate, especially in light of the maximum two-year commitment to which AEP would agree. Constellation therefore sought and obtained FERC approval to collect its entire capital investment over that two-year period, citing as precedent a comparable arrangement between University Park Energy, LLC (“UPE”) and Commonwealth Edison Company (“ComEd”) that PJM grandfathered in the course of integrating ComEd’s system

40 See PJM filing initiating FERC Docket No. ER02-2651-000 at 4 (September 30, 2002)(“2002 Schedule 6A Filing”).

into PJM.[41] Constellation indicated to the Commission its expectation that Big Sandy, like UPE, expected to collect payment under Schedule 6A's formula rates after completing recovery of 100 percent of its investment. This might also have served as the pattern for the procurement of black start services from Lincoln Generating Facility, LLC, except that, partly in response to concerns raised by the MMU, Lincoln agreed to file for a longer five-year commitment period, within which recovery was accelerated to the first two years.[42]

The MMU had concerns that Schedule 6A was not providing an appropriate framework for the procurement of black start service from new resources. The fundamental problem was that transmission customers in the PJM Region were paying over a short time the cost of substantial capital investments in black start capable resources with no assurance that those resources would continue to provide black start service after the expiration of the initial two-year term. Moreover, the rates of return for a new black start unit that recovered its full capital cost in two years and then reverted to the incentive structure under the formula rates, recovering its cost twice, were far in excess of returns typical for services procured under cost-of-service ratemaking.

In late 2007, PJM reactivated the Black Start Service Working Group ("BSSWG") in order to consider how to recover the new costs of compliance with the NERC's Critical Infrastructure Protection Standards (CIPS) applicable specifically to black start units and to update an outdated reference in the formula to the pre-RPM "Capacity Deficiency Rate." PJM's stakeholders agreed to also develop modifications to provide for a mechanism that conforms the commitment period to provide black start service to the recovery of the costs of new investment in black start equipment. The revisions to Schedule 6A developed by the BSSWG to address these and other issues were filed the FERC on February 19, 2009, and are now pending before the Commission.[43]

The current Schedule 6A calls for periodic review of the incentive factor, set at percent, which is applied to black start service related costs in a manner akin to a rate of return on equity. Under the pending proposal, all elements of the formula would be subject to biennial review.

Structure

There is no organized market for black start service in PJM. PJM in conjunction with its transmission owners identifies locations where critical black start units are needed and conducts requests for proposals to procure service at those locations. Proposals are accepted from any party willing and able to provide the service at the required location. No customers or their representatives are involved in this process. The MMU is not aware that any request for proposal process has received more than a handful of offers. This result is not unexpected, as there are a very limited number of existing facilities at particular locations indentified in the PJM's system restoration plans eligible to provide the service needed. The MMU has concerns that there is a disconnect between a service that is vital for the industry collectively to obtain and the need to secure voluntary participation in the system restoration plans from relatively few potentially cost-effective providers at the critical locations identified. Clearly, the owners of the few facilities able to respond to the requests for proposal have local market power in the provision of black start services. The significantly increasing

41 *See* Big Sandy Peaker Plant, LLC filing initiating FERC Docket No. ER06-1357 (August 11, 2006), and the Letter Order of acceptance (September 13, 2006); University Park Energy, LLC filing initiating FERC Docket No. ER04-212 (November 21, 2003), and Letter Order of acceptance (January 29, 2004).
42 *See* Lincoln Generating Facility, LLC filing initiating FERC Docket No. ER08-63-000 (October 16, 2007), and Letter Order of acceptance (December 12, 2007).
43 PJM filed the revised Schedule 6A in FERC Docket No. ER09-730-000.

costs and risks associated with providing this service as a result of more rigorous and enforceable security standards may aggravate this problem, despite PJM's efforts to address this issue.

Conduct

PJM generally has managed the request-for-proposals process in an orderly and transparent manner. PJM has been vigilant in ensuring timely and adequate provision of service in system restoration plans. The MMU is concerned that the process does not ensure adequate scrutiny of the proposals.

Performance

There is no liquidity in the provision of black start service at locations identified in system restoration plans. Although the procurement process is transparent and administered well, it is not appropriate to characterize it as a "competitive" process. The request for proposal process cannot be relied upon to ensure just and reasonable rates for black start service because the market is characterized by substantial local market power. PJM has correctly described Schedule 6A and its formula rates as a cost-of-service recovery mechanism,[44] and its performance should be evaluated in that context.

PJM's filing in FERC Docket No. ER09-730 will allow the formula under Schedule 6A to recover new investment and reasonably conform the terms of commitment between service providers and their customers. However, the MMU is concerned about the level of increases that may result from CIPS costs applicable to black start service. Certain units may incur these costs and continue to be included in system restoration plans even though the plans could be developed in a manner that would provide the same service at much lower cost. The principle obstacle is that PJM does not have the authority to develop a comprehensive system restoration plan or a clear mandate to conduct procurement in manner that results in a least cost solution. The MMU recommends that PJM and the FERC, as well state regulators, reevaluate how black start service is procured.

44 *See* 2002 Schedule 6A Filing at 4.

SECTION 7 – CONGESTION

Congestion occurs when available, least-cost energy cannot be delivered to all loads for a period because transmission facilities are not adequate to deliver that energy to some loads. When the least-cost available energy cannot be delivered to load in a transmission-constrained area, higher cost units in the constrained area must be dispatched to meet that load.[1] The result is that the price of energy in the constrained area is higher than in the unconstrained area because of the combination of transmission limitations and the cost of local generation. Locational marginal prices (LMPs) reflect the price of the lowest-cost resources available to meet loads, taking into account actual delivery constraints imposed by the transmission system. Thus LMP is an efficient way to price energy when transmission constraints exist. Congestion reflects this efficient pricing.

Congestion reflects the underlying characteristics of the power system including the nature and capability of transmission facilities and the cost and geographical distribution of generation facilities. Congestion is neither good nor bad but is a direct measure of the extent to which there are differences in the cost of generation that cannot be equalized because of transmission constraints. A complete set of markets would require direct competition between investments in transmission and generation. The transmission system provides a physical hedge against congestion. The transmission system is paid for by firm load and, as a result, firm load receives the corollary financial hedge in the form of Auction Revenue Rights (ARRs) and/or Financial Transmission Rights (FTRs). While the transmission system and, therefore, ARRs/FTRs are not guaranteed to be a complete hedge against congestion, ARRs/FTRs do provide a substantial offset to the cost of congestion to firm load.[2]

The Market Monitoring Unit (MMU) analyzed congestion and its influence on PJM markets during 2008.

Overview

Congestion Cost

- **Total congestion.** Total congestion costs increased by $271 million or 15 percent, from $1.846 billion in calendar year 2007 to $2.117 billion in calendar year 2008. Day-ahead congestion costs increased by $586 million or 28 percent, from $2.075 billion in calendar year 2007 to $2.661 billion in calendar year 2008. Balancing congestion costs decreased by $315.6 million or 137 percent, from -$229 million in calendar year 2007 to -$544.6 million in calendar year 2008. Total congestion costs have ranged from 6 percent to 9 percent of PJM annual total billings since 2003. Congestion costs were 6 percent of total PJM billings for 2008, as was the case in 2007. Total PJM billings for 2008 were $34.306 billion, a 12 percent increase from the $30.556 billion billed in 2007.

1 This is referred to as dispatching units out of economic merit order. Economic merit order is the order of all generator offers from lowest to highest cost. Congestion occurs when loadings on transmission facilities mean the next unit in merit order cannot be used and a higher cost unit must be used in its place.

2 See the *2008 State of the Market Report*, Volume II, Section 8, "Financial Transmission and Auction Revenue Rights," at "ARR and FTR Revenue and Congestion."

- **Monthly Congestion**. Fluctuations in monthly congestion costs continued to be substantial. In 2008, these differences were driven by varying load and energy import levels, different patterns of generation, weather-induced changes in demand and variations in congestion frequency on constraints affecting large portions of PJM load.

Congestion Component of LMP and Facility or Zonal Congestion

- **Congestion Component of Locational Marginal Price (LMP)**. To provide an indication of the geographic dispersion of congestion costs, the congestion component of LMP (CLMP) was calculated for control zones in PJM. Price separation between eastern, southern and western control zones in PJM was primarily a result of congestion on the AP South interface. This interface had the effect of increasing prices in eastern and southern control zones located on the constrained side of the affected facilities while reducing prices in the unconstrained western control zones.

- **Congested Facilities**. As was the case in 2007, congestion frequency was significantly higher in the Day-Ahead Market than in the Real-Time Market in 2008.[3] Day-ahead congestion frequency increased in calendar year 2008 compared to 2007. In 2008, there were 74,742 day-ahead, congestion-event hours compared to 62,616 congestion-event hours in 2007. Day-ahead, congestion-event hours increased on PJM transmission lines, transformers and the flowgates between PJM and the Midwest Independent Transmission System Operator, Inc. (Midwest ISO) while congestion frequency on internal PJM interfaces decreased in 2008 compared to 2007. Real-time congestion frequency increased in calendar year 2008 compared to 2007. In 2008, there were 21,651 real-time, congestion-event hours compared to 19,527 congestion-event hours in 2007. Real-time, congestion-event hours increased on PJM transmission lines, transformers and on the flowgates between PJM and the Midwest ISO, while interfaces saw decreases. The AP South Interface was the largest contributor to congestion costs in 2008. With $558 million in total congestion costs, it accounted for 26 percent of the total PJM congestion costs in 2008. The top five constraints in terms of congestion costs together contributed $1.282 billion, or 61 percent, of the total PJM congestion costs in 2008. The top five constraints included the AP South Interface, the Cloverdale — Lexington line, the Mount Storm – Pruntytown line and the Bedington – Black Oak and West interface constraints.

- **Zonal Congestion.** In calendar year 2008, the AP Control Zone experienced the highest congestion costs of the control zones in PJM. The $487.1 million in congestion costs in the AP Control Zone represented a 9 percent increase from the $448.6 million in congestion costs the zone had experienced in 2007. The AP South Interface contributed $145.3 million, or 30 percent of the total AP Control Zone congestion cost. The Dominion Control Zone had the second highest congestion cost in PJM in 2008. The $322.6 million in congestion costs in the Dominion Control Zone represented an 11 percent increase from the $290.8 million in congestion costs the zone had experienced in 2007. The AP South Interface contributed $177.1 million, or 55 percent of the total Dominion Control Zone congestion cost.

3 Prior state of the market reports measured real-time congestion frequency using the convention that a congestion-event hour exists if the particular facility is constrained for four or more of the 12 five-minute intervals comprising that hour. In the *2008 State of the Market Report*, in order to have a consistent metric for real-time and day-ahead congestion frequency, real-time congestion frequency is measured using the convention that an hour is constrained if any of its component five-minute intervals is constrained. Comparisons to previous periods use the new standard for both current and prior periods.

Economic Planning Process

- **Transmission and Markets.** As a general matter, transmission investments have not been fully incorporated into competitive markets. The construction of new transmission facilities can have significant impacts on energy and capacity markets, but there is no market mechanism in place that would require direct competition between transmission and generation to meet loads in an area. While the RPM construct does provide that qualifying transmission upgrades may be submitted as offers, there have been no such offers. More generally, network transmission is not built based directly on market signals because the owners of network transmission are compensated through a non market mechanism. PJM has taken a first step towards integrating transmission investments into the market through the use of economic evaluation metrics. Economic evaluation metrics can be used to determine whether there are positive economic benefits associated with an investment in transmission that might warrant the investment even when it is not required for reliability. The goal of transmission planning should ultimately be the incorporation of transmission investment decisions into market driven processes as much as possible.

- **Process Revision**. PJM has made multiple filings related to economic metrics for evaluating transmission investments. The United States Federal Energy Regulatory Commission (FERC) has required that PJM use an approach with predefined formulas for determining whether a defined transmission investment passes the cost-benefit test including explicit accounting for changes in production costs, the costs of complying with environmental regulations, generation availability trends and demand-response trends. The FERC has recently accepted the latest PJM filing in Docket No. ER06-1474.

Conclusion

Congestion reflects the underlying characteristics of the power system, including the nature and capability of transmission facilities and the cost and geographical distribution of generation facilities. Total congestion costs increased by $271 million or 15 percent, from $1.846 billion in calendar year 2007 to $2.117 billion in calendar year 2008. Day-ahead congestion costs increased by $586 million or 28 percent, from $2.075 billion in calendar year 2007 to $2.661 billion in calendar year 2008. Balancing congestion costs decreased by $315.6 million or 138 percent, from -$229 million in calendar year 2007 to -$544.6 million in calendar year 2008. Congestion costs were significantly higher in the Day-Ahead Market than in the balancing market. Congestion frequency was also significantly higher in the Day-Ahead Market than in the Real-Time Market. In the Day-Ahead Market in 2008, there were 74,742 congestion-event hours compared to 62,616 congestion-event hours in 2007. In the Real-Time Energy Market in 2008, there were 21,651 congestion-event hours compared to 19,527 congestion-event hours in 2007.

As a result of the geographic growth of PJM, efficient redispatch displaced the less efficient management of power flows across multiple borders via transmission loading relief (TLR) procedures and ramp limits. (Power flows across the new, external borders continue to be managed, in part, via TLRs and ramp limits.) Redispatch is more efficient and, at the same time, revealed the underlying inability of the transmission system to transfer the lowest-cost energy on the system to all parts of the system for all hours. The details are revealed in the analysis of temporal patterns of congestion and of congested facilities and zonal congestion. That information, made explicit over the broad PJM footprint, is an essential input to a rational market and planning process.

ARRs and FTRs served as an effective, but not total, hedge against congestion. ARR and FTR revenues hedged 97.4 percent of the total congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM for the 2007 to 2008 planning period. For the first seven months of the 2008 to 2009 planning period, ARR and FTR revenue hedged 97.2 percent of the total congestion costs within PJM.[4] FTRs were paid at 100 percent of their target allocation for the planning year ended May 31, 2008, and at 99.6 percent of their target allocation for the first seven months of the current planning year.

One constraint accounted for over a quarter of total congestion costs in 2008 and the top five constraints accounted for nearly two-thirds of total congestion costs. The AP South interface displaced the Bedington – Black Oak interface as the largest contributor to congestion costs in 2008 due to system upgrades on the Bedington – Black Oak circuit in December 2007 and the associated redefinition of the AP South interface on September 1, 2008.[5] The Bedington – Black Oak constraint has been a persistent source of large congestion costs for several years, but decreased in both congestion costs and frequency in 2008. The AP South interface is now the primary west to east transfer constraint.

The congestion metric requires careful review. Net congestion, which includes both load congestion payments and generation congestion credits, is not a good measure of the congestion costs paid by load from the perspective of the wholesale market.[6] While total congestion costs represent the overall charge or credit to a zone, the components of congestion costs measure the extent to which load or generation bear total congestion costs. Load congestion payments, when positive, measure the total congestion cost to load in an area. Load congestion payments, when negative, measure the total congestion credit to load in an area. Negative load congestion payments result when load is on the lower priced side of a constraint or constraints. For example, congestion across the AP South interface means lower prices in western control zones and higher prices in eastern and southern control zones. Load in western control zones will benefit from lower prices and receive a congestion credit (negative load congestion payment). Load in the eastern and southern control zones will incur a congestion charge (positive load congestion payment). The reverse is true for generation congestion credits. Generation congestion credits, when positive, measure the total congestion credit to generation in an area. Generation congestion credits, when negative, measure the total congestion cost to generation in an area. Negative generation congestion credits result when generation is on the lower priced side of a constraint or constraints. For example, congestion across the AP South interface means lower prices in the western control zones and higher prices in the eastern and southern control zones. Generation in the western control zones will receive lower prices and incur a congestion charge (negative generation congestion credit). Generation in the eastern and southern control zones will receive higher prices and receive a congestion credit (positive generation congestion credit).

4 See the *2008 State of the Market Report*, Volume II, Section 8, "Financial Transmission and Auction Revenue Rights," at Table 8-28, "ARR and FTR congestion hedging: Planning periods 2007 to 2008 and 2008 to 2009."

5 See "APSouth Transfer Interface," PJM Presentation to the Markets Implementation Committee (July 23, 2008) <http://www.pjm.com/~/media/committees-groups/committees/mic/20080723-item-08-apsouth-interface-changes.ashx> (554.44 kb)

6 The actual congestion payments by retail customers are a function of retail ratemaking policies and may or may not reflect an offset for congestion credits.

As an example, total congestion in 2008 in PJM was $2.117 billion, which was comprised of load congestion payments of $1.060 billion, negative generation credits of $1.089 billion and explicit congestion of -$31.1 million.

Congestion

Congestion Accounting

Transmission congestion can exist in PJM's Day-Ahead and Real-Time Energy Market. Transmission congestion charges in the Day-Ahead Energy Market can be directly hedged by FTRs. Balancing market congestion charges can be hedged by FTRs to the extent that a participant's energy flows in real time are consistent with those in the Day-Ahead Energy Market.[7]

Total congestion charges are equal to the net congestion bill plus explicit congestion charges, incurred in both the Day-Ahead Energy Market and the balancing energy market.

The net congestion bill is calculated by subtracting generating congestion credits from load congestion payments. The logic is that increased congestion payments by load are offset by increased congestion revenues to generation, for the area analyzed. Whether the net congestion bill is an appropriate measure of congestion for load depends on who pays the load congestion payments and who receives the generation congestion credits. The net congestion bill is an appropriate measure of congestion for a utility that charges load congestion payments to load and credits generation congestion credits to load. The net congestion bill is not an appropriate measure of congestion in situations where load pays the load congestion payments but does not receive the generation credits as an offset.

In the 2008 analysis of total congestion costs, load congestion payments are netted against generation congestion credits on an hourly basis, by billing organization, and then summed for the given period.[8] A billing organization may offset load congestion payments with its generation portfolio or by purchasing supply from another entity via a bilateral transaction.

Load Congestion Payments and Generation Congestion Credits are calculated for both the Day-ahead and Balancing Energy Markets.

- **Day-Ahead Load Congestion Payments**. Day-ahead load congestion payments are calculated for all cleared demand, decrement bids and Day-Ahead Energy Market sale transactions. (Decrement bids and energy sales can be thought of as scheduled load.) Day-ahead load congestion payments are calculated using MW and the load bus CLMP, the decrement bid CLMP or the CLMP at the source of the sale transaction, as applicable.

7 The terms *congestion charges* and *congestion costs* are both used to refer to the costs associated with congestion. The term, congestion charges, is used in documents by PJM's Market Settlement Operations.

8 This analysis does not treat affiliated billing organizations as a single organization. Thus, the generation congestion credits from one organization will not offset the load payments of its affiliate. This may overstate or understate the actual load payments or generation credits of an organization's parent company.

- **Day-Ahead Generation Congestion Credits**. Day-ahead generation congestion credits are calculated for all cleared generation and increment offers and Day-Ahead Energy Market purchase transactions. (Increment offers and energy purchases can be thought of as scheduled generation.) Day-ahead generation congestion credits are calculated using MW and the generator bus CLMP, the increment offer's CLMP or the CLMP at the sink of the purchase transaction, as applicable.

- **Balancing Load Congestion Payments**. Balancing load congestion payments are calculated for all deviations between a PJM member's real-time load and energy sale transactions and their day-ahead cleared demand, decrement bids and energy sale transactions. Balancing load congestion payments are calculated using MW deviations and the real-time CLMP for each bus where a deviation exists.

- **Balancing Generation Congestion Credits**. Balancing generation congestion credits are calculated for all deviations between a PJM member's real-time generation and energy purchase transactions and the day-ahead cleared generation, increment offers and energy purchase transactions. Balancing generation congestion credits are calculated using MW deviations and the real-time CLMP for each bus where a deviation exists.

- **Explicit Congestion Charges**. Explicit congestion charges are the net congestion charges associated with point-to-point energy transactions. These charges equal the product of the transacted MW and CLMP differences between sources (origins) and sinks (destinations) in the Day-Ahead Energy Market. Balancing energy market explicit congestion charges equal the product of the deviations between the real-time and day-ahead transacted MW and the differences between the real-time CLMP at the transactions' sources and sinks.

The congestion charges associated with specific constraints are the sum of the total day-ahead and balancing congestion costs associated with those constraints. The congestion charges in each zone are the sum of the congestion charges associated with each constraint that affects prices in the zone. The network nature of the transmission system means that congestion costs in a zone are frequently the result of constrained facilities located outside that zone.

Congestion costs can be both positive and negative. The CLMP is calculated with respect to the system reference bus LMP, also called the system marginal price (SMP). When a transmission constraint occurs, the resulting CLMP is positive on one side of the constraint and negative on the other side of the constraint and the corresponding congestion costs are positive or negative. For each transmission constraint, the CLMP reflects the cost of a constraint at a pricing node and is equal to the product of the constraint shadow price and the distribution factor at the respective pricing node. The total CLMP at a pricing node is the sum of all constraint contributions to LMP and is equal to the difference between the actual LMP that results from transmission constraints, excluding losses, and the SMP. If an area experiences lower prices because of a constraint, the CLMP in that area is negative.[9]

9 For an example of the congestion accounting methods used in this section, see the *2008 State of the Market Report*, Volume II, Appendix G, "Financial Transmission and Auction Revenue Rights," at Table G-1, "Congestion revenue, FTR target allocations and FTR congestion credits: Illustration."

Total Calendar Year Congestion

Congestion charges have ranged from 6 percent to 9 percent of annual total PJM billings since 2003.[10] Table 7-1 shows total congestion by year from 2003 through 2008. Total congestion charges were $2.117 billion in calendar year 2008, a 15 percent increase from $1.846 billion in calendar year 2007.

Table 7-1 Total annual PJM congestion (Dollars (Millions)): Calendar years 2003 to 2008

	Congestion Charges	Percent Change	Total PJM Billing	Percent of PJM Billing
2003	$464	NA	$6,900	7%
2004	$750	62%	$8,700	9%
2005	$2,092	179%	$22,630	9%
2006	$1,603	(23%)	$20,945	8%
2007	$1,846	15%	$30,556	6%
2008	$2,117	15%	$34,306	6%
Total	$8,872		$124,037	7%

Total congestion charges appearing in Table 7-1 include both congestion charges associated with PJM facilities and those associated with reciprocal, coordinated flowgates in the Midwest ISO whose operating limits are respected by PJM.[11]

Monthly Congestion

Table 7-2 shows that during calendar year 2008, monthly congestion charges ranged from a maximum of $436 million in June 2008 to a minimum of $78 million in December 2008. Approximately 52 percent of all calendar year 2008 congestion occurred between the months of May and August.

10 Calculated values shown in Section 7, "Congestion," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

11 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. And PJM Interconnection, L.L.C." (November 1, 2007) (Accessed February 23, 2009), Section 6.1 <http://www.pjm.com/documents/agreements/~/media/documents/agreements/joa-complete.ashx>.

Table 7-2 Monthly PJM congestion charges (Dollars (Millions)): Calendar years 2007 to 2008

	2007	2008
Jan	$112	$231
Feb	$175	$168
Mar	$160	$86
Apr	$109	$126
May	$90	$183
Jun	$188	$436
Jul	$205	$360
Aug	$207	$127
Sept	$136	$125
Oct	$122	$102
Nov	$117	$93
Dec	$226	$78

Congestion Component of LMP

The congestion component of LMP was calculated for each PJM control zone, to provide an indication of the geographic dispersion of congestion costs. The congestion component of LMP for control zones is presented in Table 7-3 for calendar years 2007 and 2008.

Table 7-3 shows overall congestion patterns in 2008. Price separation between eastern and western control zones in PJM was primarily a result of congestion on the AP South interface. This constraint generally had a positive congestion component of LMP in eastern and southern control zones located on the constrained side of the affected facilities while the unconstrained western zones had a negative congestion component of LMP.

Table 7-3 Annual average congestion component of LMP: Calendar years 2007 to 2008

	2007		2008	
Control Zone	Day Ahead	Real Time	Day Ahead	Real Time
AECO	$6.27	$6.42	$7.91	$10.77
AEP	($7.59)	($8.80)	($9.58)	($10.45)
AP	$0.77	$1.33	($0.52)	$0.29
BGE	$9.50	$12.08	$10.94	$11.07
ComEd	($7.80)	($9.42)	($11.39)	($13.45)
DAY	($8.12)	($9.54)	($10.06)	($11.18)
DLCO	($9.21)	($11.13)	($11.80)	($14.47)
Dominion	$8.43	$9.89	$8.05	$8.76
DPL	$5.72	$6.09	$7.60	$7.70
JCPL	$6.49	$7.36	$7.90	$8.64
Met-Ed	$6.25	$7.32	$6.56	$6.51
PECO	$5.02	$4.82	$5.91	$6.11
PENELEC	($1.13)	($1.46)	($0.93)	($2.33)
Pepco	$10.84	$13.00	$12.26	$12.40
PPL	$4.75	$4.89	$5.60	$5.51
PSEG	$7.05	$7.43	$7.74	$8.93
RECO	$6.77	$6.50	$6.53	$7.63

Congested Facilities

A congestion event exists when a unit or units must be dispatched out-of-merit order to control the impact of a contingency on a monitored facility or to control an actual overload. A congestion-event hour exists when a specific facility is constrained for one or more five-minute intervals within an hour. A congestion-event hour differs from a constrained hour, which is any hour during which one or more facilities are congested. Thus, if two facilities are constrained during an hour, the result is two congestion-event hours and one constrained hour. Constraints are often simultaneous, so the number of congestion-event hours exceeds the number of constrained hours and the number of congestion-event hours can exceed the number of hours in a year. In order to have a consistent metric for real-time and day-ahead congestion frequency, real-time congestion frequency is measured using the convention that an hour is constrained if any of its component five-minute intervals is constrained. This is also consistent with the way in which PJM reports real-time congestion. In 2008, there were 74,742 day-ahead, congestion-event hours, an increase of 20.1 percent from the 62,216 in 2007. In 2008, there were 21,651 real-time, congestion-event hours, a 10.9 percent increase from the 19,527 in 2007.

Congestion by Facility Type and Voltage

Both day-ahead and real-time, congestion-event hours increased on PJM transmission lines, transformers and the flowgates between PJM the Midwest ISO in 2008. Day-ahead and real-time, congestion-event hours decreased on PJM internal interfaces.

Day-ahead congestion costs increased on all facility types in 2008 except interfaces. Balancing congestion costs decreased on all facility types in 2008.

Table 7-4 provides congestion-event-hour subtotals and congestion cost subtotals comparing 2008 calendar year results by facility type: line, transformer, interface, flowgate and unclassified facilities.[12,13] For comparison, this information is presented in Table 7-5 for calendar year 2007.[14]

Total congestion costs associated with the flowgates between PJM and the Midwest ISO decreased by $13.9 million from 2007 to -$19.9 million in 2008. The State Line – Wolf Lake flowgate accounted for $5.3 million in congestion costs and was the largest contributor to positive congestion costs among flowgates in 2008. The largest contribution to negative congestion costs among flowgates came from the Pana North flowgate with -$10.3 million in 2008 congestion costs.

Total congestion costs associated with interfaces decreased from $992.3 million in 2007 to $937.4 million in 2008. Interfaces typically include multiple transmission facilities and reflect power flows into or through a wider geographic area. Interface congestion constituted 44 percent of total PJM congestion costs in 2008. Among interfaces, the AP South and Bedington – Black Oak interfaces accounted for the largest contribution to positive congestion costs in 2008. The AP South interface, with $558 million in congestion, had the highest congestion cost of any facility in PJM, accounting for 26 percent of the total PJM congestion costs in 2008. The AP South and Bedington – Black Oak interfaces together accounted for $722.6 million or 34 percent of total PJM congestion costs in 2008.

Total congestion costs associated with transmission lines increased 61 percent from $521.6 million in 2007 to $837.4 million in 2008. Transmission line congestion accounted for 40 percent of the total PJM congestion costs for 2008. The Cloverdale – Lexington and Mount Storm – Pruntytown lines together accounted for $453.4 million or 54 percent of all transmission line congestion costs and were the largest contributors to positive congestion among transmission lines in 2008. The largest contribution to negative congestion costs among transmission lines came from the Sammis – Wylie Ridge line with -$59.5 million in 2008 congestion costs.

Total congestion costs associated with transformers increased 4 percent from $325.4 million in 2007 to $338.2 million in 2008. Congestion on transformers accounted for 16 percent of the total PJM congestion costs in 2008. The Kammer and Bedington transformers together accounted for

12 Unclassified constraints appear in the Day-Ahead Market only and represent congestion costs incurred on market elements which are not posted by PJM. Congestion frequency associated with these unclassified constraints is not presented in order to be consistent with the posting of constrained facilities by PJM.

13 The term *flowgate* refers to Midwest ISO flowgates in this context.

14 For 2008, the load congestion payments and generation congestion credits represent the net load congestion payments and net generation congestion credits for an organization, as this shows the extent to which each organization's load or generation was exposed to congestion costs. The results are then summed across facility type, voltage, and zone or region. In the *2007 State of the Market Report*, the load congestion payments and generation congestion credits were not netted against each other and therefore will not match the 2007 values reported in the following tables. The calculation of the net congestion bill was unaffected and remains the same as in prior years.

$131.5 million or 39 percent of all transformer congestion costs and were the largest contributors to positive congestion costs among transformers in 2008.

Table 7-4 Congestion summary (By facility type): Calendar year 2008

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Type	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Flowgate	$9.6	($14.3)	$11.8	$35.7	($7.2)	$3.5	($44.8)	($55.5)	($19.9)	2,417	2,031
Interface	$368.3	($579.2)	$44.7	$992.2	($18.2)	$20.3	($16.3)	($54.8)	$937.4	8,866	2,196
Line	$597.5	($423.0)	$120.0	$1,140.6	($129.1)	$27.6	($146.4)	($303.1)	$837.4	50,637	12,710
Transformer	$299.9	($139.6)	$29.9	$469.4	($71.4)	$27.7	($32.0)	($131.2)	$338.2	12,822	4,714
Unclassified	$10.9	($10.6)	$2.0	$23.4	$0.0	$0.0	($0.0)	($0.0)	$23.4	NA	NA
Total	$1,286.1	($1,166.7)	$208.4	$2,661.2	($225.9)	$79.2	($239.5)	($544.6)	$2,116.6	74,742	21,651

Table 7-5 Congestion summary (By facility type): Calendar year 2007

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Type	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Flowgate	$2.2	($2.4)	$4.4	$9.0	$1.0	$1.6	($14.4)	($15.0)	($6.0)	1,489	1,069
Interface	$949.3	($19.6)	$58.8	$1,027.7	$6.8	$23.4	($18.7)	($35.4)	$992.3	9,798	2,856
Line	$401.5	($204.1)	$67.6	$673.1	($16.2)	$33.9	($101.4)	($151.5)	$521.6	39,071	10,916
Transformer	$400.9	$80.6	$32.1	$352.4	($2.1)	$0.6	($24.3)	($27.0)	$325.4	11,858	4,686
Unclassified	$10.1	($1.0)	$1.3	$12.4	$0.0	$0.0	$0.0	$0.0	$12.4	NA	NA
Total	$1,764.0	($146.4)	$164.2	$2,074.6	($10.5)	$59.5	($158.9)	($228.9)	$1,845.7	62,216	19,527

Table 7-6 shows congestion costs by facility voltage class. In comparison to 2007 (shown in Table 7-7), congestion costs decreased across 765 kV, 345 kV, 115 kV, 34 kV and 12 kV class facilities in 2008. Congestion costs increased across 500 kV, 230 kV, 138 kV, 69 kV and unclassified class facilities in 2008.

Congestion costs associated with 765 kV facilities decreased 30 percent from $7.0 million in 2007 to the $4.9 million experienced in 2008. Congestion on 765 kV facilities comprised less than 1 percent of total 2008 PJM congestion costs.

Congestion costs associated with 500 kV facilities increased 19 percent from $1.288 billion in 2007 to $1.528 billion in 2008. Congestion on 500 kV facilities comprised 72 percent of total 2008 PJM congestion costs. The AP South interface, the Cloverdale – Lexington line, and the Mount Storm – Pruntytown line together accounted for $1,011.4 million or 66 percent of all 500 kV congestion costs; they were the largest contributors to positive congestion among 500 kV facilities in 2008.

Congestion costs associated with 230 kV facilities increased 7 percent from $227.0 million in 2007 to $243.1 million in 2008. Congestion on 230 kV facilities comprised 11 percent of total 2008 PJM congestion costs. The Branchburg – Readington line accounted for $30.9 million or 13 percent of all 230 kV congestion costs and was the largest contributor to positive congestion among 230 kV facilities in 2008.

Congestion costs associated with 138 kV facilities increased 18 percent from $218.9 million in 2007 to $257.3 million in 2008. Congestion on 138 kV facilities comprised 12 percent of total 2008 PJM congestion costs. The Bedington and Meadowbrook transformers together accounted for $91.9 million or 36 percent of all 138 kV congestion costs and were the largest contributors to positive congestion among 138 kV facilities in 2008.

Table 7-6 Congestion summary (By facility voltage): Calendar year 2008

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Voltage (kV)	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
765	$1.6	($3.0)	$0.1	$4.7	$1.2	$0.5	($0.4)	$0.2	$4.9	83	31
500	$718.1	($861.2)	$90.1	$1,669.4	($98.5)	($0.7)	($44.1)	($141.9)	$1,527.5	19,171	6,793
345	$52.9	($62.6)	$46.7	$162.2	($38.6)	$8.0	($118.6)	($165.1)	($2.9)	5,887	2,601
230	$213.8	($106.8)	$28.8	$349.4	($33.9)	$49.7	($22.7)	($106.3)	$243.1	14,817	3,927
138	$191.9	($121.0)	$39.1	$351.9	($38.5)	$8.4	($47.7)	($94.7)	$257.3	20,551	6,270
115	$62.3	($4.5)	$1.4	$68.2	($15.4)	$11.4	($5.7)	($32.5)	$35.7	8,042	1,445
69	$34.7	$3.0	$0.4	$32.0	($2.3)	$1.8	($0.2)	($4.3)	$27.7	6,191	560
34	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.0)	0	24
Unclassified	$10.9	($10.6)	$2.0	$23.4	$0.0	$0.0	($0.0)	($0.0)	$23.4	NA	NA
Total	$1,286.1	($1,166.7)	$208.4	$2,661.2	($225.9)	$79.2	($239.5)	($544.6)	$2,116.6	74,742	21,651

Table 7-7 Congestion summary (By facility voltage): Calendar year 2007

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Voltage (kV)	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
765	$5.8	($0.8)	$1.3	$7.8	$0.0	$0.2	($0.6)	($0.8)	$7.0	422	17
500	$1,441.8	$214.6	$93.7	$1,320.9	$24.8	$7.2	($50.2)	($32.6)	$1,288.3	15,691	5,938
345	$146.0	$71.9	$18.1	$92.2	($3.6)	$15.4	($50.6)	($69.6)	$22.6	3,719	1,973
230	($96.1)	($359.2)	$18.0	$281.1	($13.8)	$18.5	($21.8)	($54.1)	$227.0	11,927	3,141
138	$186.7	($52.2)	$30.0	$268.9	($5.5)	$6.5	($37.9)	($49.9)	$218.9	16,569	5,313
115	$48.8	($10.8)	$1.5	$61.1	($9.6)	$8.7	$2.4	($16.0)	$45.1	6,337	1,916
69	$21.0	($9.0)	$0.2	$30.2	($2.8)	$2.9	($0.2)	($5.9)	$24.3	7,434	1,229
12	($0.1)	($0.1)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	117	0
Unclassified	$10.1	($1.0)	$1.3	$12.4	$0.0	$0.0	$0.0	$0.0	$12.4	NA	NA
Total	$1,764.0	($146.4)	$164.2	$2,074.6	($10.5)	$59.5	($158.9)	($228.9)	$1,845.7	62,216	19,527

Constraint Duration

Table 7-8 lists calendar year 2007 and 2008 constraints that were most frequently in effect and shows changes in congestion-event hours from 2007 to 2008.[15]

The Bedington – Black Oak and AP South interface constraints saw the biggest decrease and increase in congestion-event hours, respectively. The Cloverdale – Lexington line decreased in congestion-event hours from 2007 to 2008, but still remained one of the most frequently occurring transmission constraints. The Mount Storm – Pruntytown line increased in day-ahead, congestion-event hours by 29 percent and six percent in real-time. The West interface constraint increased by 15 percent and one percent in day-ahead and real-time, congestion-event hours, respectively. These five constraints were also the top contributors to 2008 congestion costs.

Table 7-8 Top 25 constraints with frequent occurrence: Calendar years 2007 to 2008

			Event Hours						Percent of Annual Hours					
			Day Ahead			Real Time			Day Ahead			Real Time		
No.	Constraint	Type	2007	2008	Change	2007	2008	Change	2007	2008	Change	2007	2008	Change
1	Bedington - Black Oak	Interface	5,493	1,384	(4,109)	1,836	279	(1,557)	63%	16%	(47%)	21%	3%	(18%)
2	AP South	Interface	706	3,572	2,866	133	997	864	8%	41%	33%	2%	11%	10%
3	Mount Storm - Pruntytown	Line	33	2,559	2,526	151	722	571	0%	29%	29%	2%	8%	6%
4	Sammis - Wylie Ridge	Line	90	1,915	1,825	109	1,239	1,130	1%	22%	21%	1%	14%	13%
5	Trainer - Delco Tap	Line	0	2,218	2,218	0	0	0	0%	25%	25%	0%	0%	0%
6	Kammer	Transformer	2,005	3,069	1,064	947	1,567	620	23%	35%	12%	11%	18%	7%
7	Branchburg - Readington	Line	2,324	1,121	(1,203)	721	271	(450)	27%	13%	(14%)	8%	3%	(5%)
8	West	Interface	359	1,690	1,331	338	385	47	4%	19%	15%	4%	4%	1%
9	Krendale - Seneca	Line	89	1,389	1,300	16	24	8	1%	16%	15%	0%	0%	0%
10	Mount Storm	Transformer	0	935	935	0	373	373	0%	11%	11%	0%	4%	4%
11	Atlantic - Larrabee	Line	680	1,556	876	134	380	246	8%	18%	10%	2%	4%	3%
12	Pumphrey - Westport	Line	9	1,092	1,083	0	0	0	0%	12%	12%	0%	0%	0%
13	Monroe	Transformer	6	815	809	3	247	244	0%	9%	9%	0%	3%	3%
14	Leonia - New Milford	Line	0	919	919	0	84	84	0%	10%	10%	0%	1%	1%
15	East Frankfort - Crete	Line	38	1,002	964	0	0	0	0%	11%	11%	0%	0%	0%
16	Dickerson - Plesant View	Line	34	844	810	68	218	150	0%	10%	9%	1%	2%	2%
17	Cedar Grove - Clifton	Line	145	793	648	69	372	303	2%	9%	7%	1%	4%	3%
18	Dunes Acres - Michigan City	Flowgate	150	687	537	96	435	339	2%	8%	6%	1%	5%	4%
19	5004/5005 Interface	Interface	1,512	736	(776)	386	411	25	17%	8%	(9%)	4%	5%	0%
20	East Towanda	Transformer	1,055	803	(252)	410	306	(104)	12%	9%	(3%)	5%	3%	(1%)
21	Cloverdale - Lexington	Line	3,704	3,529	(175)	1,885	1,739	(146)	42%	40%	(2%)	22%	20%	(2%)
22	Pinehill - Stratford	Line	3,274	3,088	(186)	0	0	0	37%	35%	(2%)	0%	0%	0%
23	State Line - Wolf Lake	Flowgate	1,241	1,342	101	590	341	(249)	14%	15%	1%	7%	4%	(3%)
24	Bedington	Transformer	928	1,192	264	429	299	(130)	11%	14%	3%	5%	3%	(1%)
25	Mahans Lane - Tidd	Line	727	847	120	210	211	1	8%	10%	1%	2%	2%	0%

15 Presented in descending order of absolute change between 2007 and 2008 day-ahead and real-time, congestion-event hours.

Constraint Costs

Table 7-9 and Table 7-10 present the top constraints affecting congestion costs by facility for calendar years 2007 and 2008.[16] The AP South Interface was the largest contributor to congestion costs in 2008. With $558 million in total congestion costs, it accounted for 26 percent of the total PJM congestion costs in 2008. The top five constraints in terms of congestion costs together comprised 61 percent of the total PJM congestion costs in 2008.

Table 7-9 Top 25 constraints affecting annual PJM congestion costs (By facility): Calendar year 2008

				Congestion Costs (Millions)									Percent of Total PJM Congestion Costs
				Day Ahead				Balancing					
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	2008
1	AP South	Interface	500	$196.2	($367.1)	$23.8	$587.1	($11.9)	$5.5	($11.7)	($29.1)	$558.0	26%
2	Cloverdale - Lexington	Line	AEP	$153.8	($77.5)	$9.0	$240.3	($20.6)	($18.6)	($9.1)	($11.0)	$229.3	11%
3	Mount Storm - Pruntytown	Line	AP	$60.1	($157.0)	$15.8	$232.8	($21.6)	($15.8)	($2.9)	($8.7)	$224.1	11%
4	Bedington - Black Oak	Interface	500	$52.2	($106.2)	$7.0	$165.5	($1.3)	($0.6)	($0.2)	($0.9)	$164.6	8%
5	West	Interface	500	$67.8	($42.5)	$8.0	$118.3	($2.0)	$8.2	($2.2)	($12.4)	$105.9	5%
6	Kammer	Transformer	500	$100.9	$23.3	$10.4	$88.0	($17.0)	($3.7)	$1.4	($11.9)	$76.1	4%
7	Sammis - Wylie Ridge	Line	AP	$18.4	($5.9)	$23.1	$47.4	($29.7)	$5.2	($71.9)	($106.9)	($59.5)	(3%)
8	Bedington	Transformer	AP	$21.5	($33.2)	$2.2	$56.9	($1.8)	($1.4)	($1.1)	($1.4)	$55.4	3%
9	5004/5005 Interface	Interface	500	$16.5	($34.9)	$3.0	$54.4	($2.8)	$6.9	($2.0)	($11.7)	$42.7	2%
10	Mount Storm	Transformer	AP	$22.3	($61.3)	$10.0	$93.6	($20.9)	$14.1	($15.9)	($50.9)	$42.7	2%
11	East	Interface	500	$21.7	($17.5)	$1.2	$40.4	($0.1)	($0.0)	$0.0	($0.0)	$40.4	2%
12	Atlantic - Larrabee	Line	JCPL	$41.1	($15.4)	$5.4	$61.9	($9.7)	$8.2	($4.8)	($22.7)	$39.2	2%
13	Meadow Brook	Transformer	AP	$21.8	($17.5)	$0.8	$40.1	($4.4)	($1.2)	($0.4)	($3.6)	$36.5	2%
14	Branchburg - Readington	Line	PSEG	$31.0	($12.2)	$4.8	$48.1	($6.4)	$8.8	($2.0)	($17.2)	$30.9	1%
15	East Frankfort - Crete	Line	ComEd	$7.7	($13.8)	$6.7	$28.2	$0.0	$0.0	$0.0	$0.0	$28.2	1%
16	Aqueduct - Doubs	Line	AP	$23.7	($3.9)	$0.5	$28.0	$0.0	($0.1)	($0.0)	$0.1	$28.1	1%
17	Central	Interface	500	$13.9	($11.1)	$1.6	$26.6	($0.1)	$0.0	$0.1	($0.0)	$26.6	1%
18	Axton	Transformer	AEP	$9.1	($15.4)	$1.6	$26.2	$0.0	$0.0	$0.0	$0.0	$26.2	1%
19	Unclassified	Unclassified	Unclassified	$10.9	($10.6)	$2.0	$23.4	$0.0	$0.0	($0.0)	($0.0)	$23.4	1%
20	Harwood - Susquehanna	Line	PPL	$9.0	($19.9)	$0.5	$29.4	($2.6)	$3.0	($0.7)	($6.3)	$23.2	1%
21	Krendale - Seneca	Line	AP	$18.6	$3.4	$7.4	$22.5	($0.1)	$0.0	($0.1)	($0.3)	$22.3	1%
22	Dickerson - Plesant View	Line	Pepco	$41.5	$24.9	$2.2	$18.8	($0.4)	($1.2)	($1.4)	($0.6)	$18.3	1%
23	Bristers - Ox	Line	Dominion	$8.7	($7.4)	($0.9)	$15.3	$0.5	$0.4	$0.4	$0.5	$15.8	1%
24	North Seaford - Pine Street	Line	DPL	$21.2	$5.4	$0.1	$16.0	($1.0)	($0.6)	($0.1)	($0.6)	$15.4	1%
25	Branchburg - Flagtown	Line	PSEG	$12.2	($4.1)	$0.2	$16.4	$0.5	$1.0	($1.1)	($1.6)	$14.8	1%

16 Presented in descending order of annual total congestion costs.

Table 7-10 Top 25 constraints affecting annual PJM congestion costs (By facility): Calendar year 2007

				Congestion Costs (Millions)									Percent of Total PJM Congestion Costs
				Day Ahead				Balancing					
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	2007
1	Bedington - Black Oak	Interface	500	$865.4	$171.2	$43.4	$737.6	$3.0	$10.3	($16.2)	($23.5)	$714.0	39%
2	Cloverdale - Lexington	Line	AEP	$347.8	$146.6	$22.4	$223.6	$12.2	($13.7)	($22.5)	$3.5	$227.1	12%
3	5004/5005 Interface	Interface	500	$30.0	($85.3)	$5.7	$121.0	$0.4	$4.7	($0.3)	($4.6)	$116.5	6%
4	AP South	Interface	500	$87.0	($7.0)	$4.3	$98.4	$2.2	$0.1	$1.0	$3.1	$101.5	5%
5	Kammer	Transformer	500	$137.3	$89.6	$11.6	$59.2	$2.0	($6.7)	($3.7)	$5.1	$64.3	3%
6	Branchburg - Readington	Line	PSEG	($187.3)	($278.7)	$9.4	$100.8	($16.4)	$12.9	($8.4)	($37.6)	$63.1	3%
7	Bedington	Transformer	AP	$39.2	($21.1)	$2.9	$63.1	($3.9)	($2.5)	($2.0)	($3.4)	$59.7	3%
8	Meadow Brook	Transformer	AP	$20.4	($23.8)	$0.7	$44.9	($0.5)	($1.0)	($0.4)	$0.0	$44.9	2%
9	Central	Interface	500	($29.9)	($59.7)	$2.5	$32.4	$0.0	$0.0	$0.0	$0.0	$32.4	2%
10	Atlantic - Larrabee	Line	JCPL	$20.1	($8.5)	$1.7	$30.3	($3.2)	$3.2	($0.8)	($7.2)	$23.1	1%
11	Branchburg - Flagtown	Line	PSEG	$12.5	($8.7)	$0.4	$21.5	$0.2	$0.9	($1.3)	($2.0)	$19.5	1%
12	Wylie Ridge	Transformer	AP	$68.4	$47.1	$10.1	$31.3	($2.2)	$0.6	($9.6)	($12.4)	$18.9	1%
13	Brunner Island - Yorkana	Line	Met-Ed	$11.4	($3.4)	$0.1	$14.9	$1.9	($1.7)	$0.1	$3.7	$18.6	1%
14	East	Interface	500	($8.9)	($25.6)	$0.8	$17.5	($0.0)	($0.0)	($0.0)	($0.0)	$17.4	1%
15	Amos	Transformer	AEP	$9.7	($8.8)	$0.5	$18.9	$3.5	$2.1	($3.4)	($2.0)	$17.0	1%
16	Conastone	Transformer	BGE	$7.5	($5.9)	$0.4	$13.8	$1.6	$0.3	($0.3)	$1.0	$14.8	1%
17	Kanawha - Matt Funk	Line	AEP	$16.0	$2.2	$1.8	$15.5	$0.1	$0.6	($0.3)	($0.8)	$14.7	1%
18	Doubs	Transformer	AP	$13.9	($0.9)	$0.5	$15.3	($0.5)	($0.7)	($0.7)	($0.5)	$14.7	1%
19	Beckett - Paulsboro	Line	AECO	$11.7	($4.5)	$0.1	$16.3	($2.5)	($0.5)	($0.0)	($2.1)	$14.2	1%
20	Bedington - Nipetown	Line	AP	$16.4	$1.9	$0.6	$15.0	$0.2	$0.5	($0.8)	($1.1)	$13.9	1%
21	Cloverdale	Transformer	AEP	$14.5	$1.5	$1.5	$14.5	($0.4)	($0.0)	($0.7)	($1.0)	$13.5	1%
22	Darwin - Eugene	Line	AEP	($0.1)	($3.4)	$0.1	$3.3	$0.6	$6.6	($9.9)	($16.0)	($12.6)	(1%)
23	Unclassified	Unclassified	Unclassified	$10.1	($1.0)	$1.3	$12.4	$0.0	$0.0	$0.0	$0.0	$12.4	1%
24	West	Interface	500	$5.5	($12.0)	$2.0	$19.4	$0.3	$5.1	($3.6)	($8.4)	$11.0	1%
25	Axton	Transformer	AEP	$10.2	$0.8	$1.1	$10.5	$0.0	$0.0	$0.0	$0.0	$10.5	1%

Congestion-Event Summary for Midwest ISO Flowgates

PJM and the Midwest ISO have a joint operating agreement (JOA) which defines a coordinated methodology for congestion management. This agreement establishes reciprocal, coordinated flowgates in the combined footprint whose operating limits are respected by the operators of both organizations.[17] A flowgate is a representative modeling of facilities or groups of facilities that may act as constraint points on the regional system.[18] PJM models these coordinated flowgates and controls for them in its security-constrained, economic dispatch. Table 7-11 and Table 7-12 show the Midwest ISO flowgates which PJM took dispatch action to control during 2008 and 2007, respectively, and which had the greatest congestion cost impact on PJM. Total congestion costs are the sum of the day-ahead and balancing congestion cost components. Total congestion costs associated with a given constraint may be positive or negative in value. The top congestion cost impacts for Midwest ISO flowgates affecting PJM dispatch are presented by constraint, in descending order of the absolute value of total congestion costs. Among Midwest ISO flowgates in 2008, the State Line – Wolf Lake flowgate made the most significant contribution to positive congestion while the Pana North flowgate made the most significant contribution to negative congestion. Among Midwest ISO flowgates in 2007, the Crete – St. Johns Tap and Tower Road flowgates made the most significant contributions to positive congestion, while the State Line – Wolf Lake flowgate made the most significant negative contribution.

Table 7-11 Top congestion cost impacts from Midwest ISO flowgates affecting PJM dispatch (By facility): Calendar year 2008

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Pana North	Flowgate	Midwest ISO	$0.7	($1.8)	$0.6	$3.1	($0.7)	$1.4	($11.5)	($13.5)	($10.5)	190	639
Pleasant Prairie - Zion	Flowgate	Midwest ISO	$0.0	$0.0	$0.0	$0.0	($0.7)	$0.2	($5.3)	($6.2)	($6.2)	0	67
Lanesville	Flowgate	Midwest ISO	$0.2	($0.4)	$0.3	$0.9	($0.2)	$0.8	($5.7)	($6.7)	($5.8)	60	153
State Line - Wolf Lake	Flowgate	Midwest ISO	$2.2	($4.4)	$5.0	$11.7	($1.0)	$1.2	($4.1)	($6.3)	$5.3	1,342	341
Schahfer - Burr Oak	Flowgate	Midwest ISO	$0.2	($0.4)	$0.1	$0.7	($1.2)	($0.7)	($2.3)	($2.7)	($2.0)	38	160
Rising	Flowgate	Midwest ISO	$0.0	($0.0)	$0.0	$0.1	($0.2)	$0.0	($1.8)	($2.0)	($1.9)	16	89
Crete - St Johns Tap	Flowgate	Midwest ISO	$0.9	($1.3)	$0.3	$2.5	($0.2)	$0.1	($0.4)	($0.7)	$1.8	84	14
Dunes Acres - Michigan City	Flowgate	Midwest ISO	$5.3	($6.0)	$5.5	$16.8	($2.9)	$0.2	($13.0)	($16.1)	$0.7	687	435
Breed - Wheatland	Flowgate	Midwest ISO	$0.0	$0.0	$0.0	$0.0	$0.1	$0.2	($0.3)	($0.5)	($0.5)	0	11
State Line - Roxana	Flowgate	Midwest ISO	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.1	($0.3)	($0.4)	($0.4)	0	30
Ontario Hydro - NYISO	Flowgate	Midwest ISO	$0.0	$0.0	$0.0	$0.0	($0.3)	($0.1)	($0.0)	($0.2)	($0.2)	0	15
Krendale - Seneca	Flowgate	Midwest ISO	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.0	($0.0)	($0.2)	($0.2)	0	23
Eugene - Bunsonville	Flowgate	Midwest ISO	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.1)	($0.1)	($0.1)	0	12
Salem	Flowgate	Midwest ISO	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.1	$0.1	0	1
DC Cook - Palisades	Flowgate	Midwest ISO	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.1	$0.0	$0.0	0	3

17 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. And PJM Interconnection, L.L.C." (November 1, 2007) (Accessed February 23, 2009) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/joa-complete.ashx>.

18 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. And PJM Interconnection, L.L.C." (November 1, 2007) (Accessed February 23, 2009) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/joa-complete.ashx>.

Table 7-12 Top congestion cost impacts from Midwest ISO flowgates affecting PJM dispatch (By facility): Calendar year 2007

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
State Line - Wolf Lake	Flowgate	Midwest ISO	$1.3	($2.2)	$3.9	$7.3	$0.6	$1.4	($8.7)	($9.5)	($2.2)	1,241	590
Lanesville	Flowgate	Midwest ISO	$1.2	$0.4	($0.0)	$0.7	($0.1)	$0.3	($2.1)	($2.4)	($1.7)	48	50
Pana North	Flowgate	Midwest ISO	$0.0	($0.0)	$0.0	$0.1	$0.1	$0.1	($1.8)	($1.8)	($1.7)	20	152
Salem	Flowgate	Midwest ISO	$0.0	$0.0	$0.0	$0.0	($0.2)	$0.1	($0.1)	($0.4)	($0.4)	0	19
Crete - St Johns Tap	Flowgate	Midwest ISO	$0.2	($0.0)	$0.1	$0.3	$0.0	$0.0	($0.1)	($0.1)	$0.3	20	4
Tower Road	Flowgate	Midwest ISO	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.2	$0.2	$0.2	0	11
Dunes Acres - Michigan City	Flowgate	Midwest ISO	($0.5)	($0.6)	$0.4	$0.5	$0.5	($0.5)	($1.7)	($0.7)	($0.2)	150	96
Coffeen - Pana North	Flowgate	Midwest ISO	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.3	$0.2	$0.2	0	6
Seneca - Krendale	Flowgate	Midwest ISO	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	($0.1)	($0.2)	($0.2)	0	16
Queenston Flow West	Flowgate	Midwest ISO	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	($0.1)	($0.1)	($0.1)	0	16
NE Ohio	Flowgate	Midwest ISO	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.2	$0.1	($0.1)	($0.1)	0	8
Breed - West Casey	Flowgate	Midwest ISO	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	($0.1)	($0.1)	($0.1)	0	2
Rising	Flowgate	Midwest ISO	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.1)	($0.0)	($0.0)	0	6
Eau Claire - Arpin	Flowgate	Midwest ISO	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.0)	($0.0)	0	35
Pierce	Flowgate	Midwest ISO	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.0	0	43

Congestion-Event Summary for the 500 kV System

Constraints on the 500 kV system generally have a regional impact. Table 7-13 and Table 7-14 show the 500 kV constraints impacting congestion costs in PJM. Total congestion costs are the sum of the day-ahead and balancing congestion cost components. Total congestion costs associated with a given constraint may be positive or negative in value. The 500 kV constraints impacting congestion costs in PJM are presented by constraint, in descending order of the absolute value of total congestion costs. In 2008, the AP South and Bedington – Black Oak interface constraints contributed to positive congestion while the Juniata – Keystone and Cabot – Wylie Ridge lines contributed to negative congestion. In 2007, the Bedington — Black Oak and 5004/5005 interface constraints contributed to positive congestion. In 2007, the Conemaugh – Hunterstown line was the largest contributor to negative congestion.

Table 7-13 Regional constraints summary (By facility): Calendar year 2008

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
AP South	Interface	500	$196.2	($367.1)	$23.8	$587.1	($11.9)	$5.5	($11.7)	($29.1)	$558.0	3,572	997
Bedington - Black Oak	Interface	500	$52.2	($106.2)	$7.0	$165.5	($1.3)	($0.6)	($0.2)	($0.9)	$164.6	1,384	279
West	Interface	500	$67.8	($42.5)	$8.0	$118.3	($2.0)	$8.2	($2.2)	($12.4)	$105.9	1,690	385
Kammer	Transformer	500	$100.9	$23.3	$10.4	$88.0	($17.0)	($3.7)	$1.4	($11.9)	$76.1	3,069	1,567
5004/5005 Interface	Interface	500	$16.5	($34.9)	$3.0	$54.4	($2.8)	$6.9	($2.0)	($11.7)	$42.7	736	411
East	Interface	500	$21.7	($17.5)	$1.2	$40.4	($0.1)	($0.0)	$0.0	($0.0)	$40.4	758	12
Central	Interface	500	$13.9	($11.1)	$1.6	$26.6	($0.1)	$0.0	$0.1	($0.0)	$26.6	726	42
Fort Martin - Harrison	Line	500	$2.0	($0.3)	$0.4	$2.7	$0.0	$0.0	$0.0	$0.0	$2.7	45	0
Juniata - Keystone	Line	500	$0.0	$0.0	$0.0	$0.0	($0.8)	$0.4	$0.2	($1.0)	($1.0)	0	21
Conemaugh - Keystone	Line	500	$0.4	($0.2)	$0.2	$0.8	$0.9	$0.8	($0.1)	$0.1	$0.9	16	41
Cabot - Wylie Ridge	Line	500	$0.0	$0.0	$0.0	$0.0	$0.0	$0.7	($0.1)	($0.8)	($0.8)	0	6
AEP/DOM	Interface	500	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.2	($0.2)	($0.5)	($0.5)	0	49
Doubs - Mount Storm	Line	500	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.1)	$0.1	$0.1	$0.1	0	6
Conemaugh - Hunterstown	Line	500	$1.6	($1.6)	$0.4	$3.6	($0.5)	$1.3	($1.9)	($3.6)	($0.1)	62	98
Harrison - Pruntytown	Line	500	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.1)	($0.0)	$0.0	$0.0	0	2

Table 7-14 Regional constraints summary (By facility): Calendar year 2007

			Congestion Costs (Millions)									Event Hours	
			Day Ahead				Balancing						
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Bedington - Black Oak	Interface	500	$865.4	$171.2	$43.4	$737.6	$3.0	$10.3	($16.2)	($23.5)	$714.0	5,493	1,836
5004/5005 Interface	Interface	500	$30.0	($85.3)	$5.7	$121.0	$0.4	$4.7	($0.3)	($4.6)	$116.5	1,512	386
AP South	Interface	500	$87.0	($7.0)	$4.3	$98.4	$2.2	$0.1	$1.0	$3.1	$101.5	706	133
Kammer	Transformer	500	$137.3	$89.6	$11.6	$59.2	$2.0	($6.7)	($3.7)	$5.1	$64.3	2,005	947
Central	Interface	500	($29.9)	($59.7)	$2.5	$32.4	$0.0	$0.0	$0.0	$0.0	$32.4	1,334	25
East	Interface	500	($8.9)	($25.6)	$0.8	$17.5	($0.0)	($0.0)	($0.0)	($0.0)	$17.4	304	5
West	Interface	500	$5.5	($12.0)	$2.0	$19.4	$0.3	$5.1	($3.6)	($8.4)	$11.0	359	338
Conemaugh - Hunterstown	Line	500	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.5	($0.0)	($0.7)	($0.7)	0	9
MAAC - Scarcity	Interface	500	$0.0	$0.0	$0.0	$0.0	$1.0	$2.1	$1.0	($0.1)	($0.1)	0	3
Alburtis - Branchburg	Line	500	$0.0	$0.0	$0.0	$0.0	($0.1)	($0.1)	$0.0	$0.1	$0.1	0	4
Doubs - Mount Storm	Line	500	$0.0	$0.0	$0.0	$0.0	($0.1)	($0.1)	($0.0)	($0.1)	($0.1)	0	4
Harrison - Pruntytown	Line	500	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.0	0	3
Harrison Tap - Kammer	Line	500	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.0)	($0.0)	($0.0)	0	2

Congestion on the Bedington — Black Oak and AP South Interfaces

The AP extra-high-voltage (EHV) system is the primary conduit for energy transfers from the AP and midwestern generating resources to southwestern PJM and eastern Virginia load and, to a lesser extent, to the central and eastern portion of the PJM Mid-Atlantic Region. Two AP interface constraints, AP South and Bedington – Black Oak, often restrict west-to-east energy transfers across the AP EHV system. In December 2007, transmission system upgrades were completed at the Bedington – Black Oak circuit and have since made the AP South interface the primary west to east transfer constraint. These upgrades shifted both congestion costs and frequency from the Bedington – Black Oak interface to the AP South interface. In addition, the AP South interface definition was updated to include the Mount Storm – Valley 500 kV transmission line in September 2008. Table 7-15 shows a monthly breakdown of congestion-event hours and congestion costs. After August 2008, congestion frequency on the Bedington – Black Oak interface was much less than the AP South interface and congestion costs reflect this.

Table 7-15 Monthly congestion cost and frequency summary for the Bedington – Black Oak and AP South interfaces: Calendar years 2007 to 2008

	Event Hours						Congestion Costs (Millions)					
	Bedington - Black Oak			AP South			Bedington - Black Oak			AP South		
Month	2007	2008	Change	2007	2008	Change	2007	2008	Change	2007	2008	Change
Jan	724	349	(375)	37	292	255	$47.2	$55.5	$8.4	$6.6	$40.0	$33.4
Feb	1,006	216	(790)	62	379	317	$79.4	$16.4	($63.0)	$5.7	$60.2	$54.6
Mar	759	85	(674)	29	144	115	$64.2	$5.4	($58.9)	$1.2	$12.9	$11.6
Apr	450	46	(404)	204	343	139	$44.2	$2.9	($41.3)	$11.8	$39.5	$27.7
May	175	399	224	79	302	223	$13.1	$36.2	$23.1	$9.4	$34.1	$24.7
Jun	357	260	(97)	33	436	403	$38.0	$31.0	($7.0)	$3.0	$154.4	$151.3
Jul	771	107	(664)	132	425	293	$88.3	$9.4	($78.9)	$23.7	$98.2	$74.5
Aug	906	70	(836)	22	304	282	$110.6	$2.4	($108.2)	$2.0	$20.7	$18.7
Sept	636	33	(603)	62	326	264	$64.2	$3.9	($60.3)	$8.8	$15.0	$6.2
Oct	504	41	(463)	5	549	544	$51.1	($0.1)	($51.2)	$0.3	$18.8	$18.5
Nov	775	13	(762)	8	545	537	$76.1	($0.7)	($76.8)	$0.2	$29.9	$29.7
Dec	266	44	(222)	166	524	358	$37.6	$2.2	($35.4)	$28.7	$34.4	$5.6
Total	7,329	1,663	(5,666)	839	4,569	3,730	$714.0	$164.6	($549.4)	$101.5	$558.0	$456.5

The AP South interface was the largest contributor to congestion costs of any facility in PJM in calendar year 2008. In 2008, congestion costs associated with the AP South and Bedington – Black Oak interface constraints were $558 million and $164.6 million, respectively. In 2008, the AP South and Bedington – Black Oak interfaces were constrained 4,569 hours and 1,663 hours, respectively. In 2007, congestion costs associated with Bedington – Black Oak and AP South were $714.0 million and $101.5 million, respectively. In 2007, Bedington – Black Oak and AP South were constrained 7,329 hours and 839 hours, respectively.

Zonal Congestion

Summary

Day-ahead and balancing congestion costs within specific zones for calendar years 2008 and 2007 are presented in Table 7-16 and Table 7-17. While total congestion costs represent the overall charge or credit to a zone, the components of congestion costs measure the extent to which load or generation bear total congestion costs. Load congestion payments, when positive, measure the total congestion cost to load in an area. Load congestion payments, when negative, measure the total congestion credit to load in an area. Negative load congestion payments result when load is on the lower priced side of a constraint or constraints. For example, congestion across the AP South interface means lower prices in western control zones and higher prices in eastern and southern control zones. Load in western control zones will benefit from lower prices and receive a congestion credit (negative load congestion payment). Load in the eastern and southern control zones will incur a congestion charge (positive load congestion payment). The reverse is true for generation congestion credits. Generation congestion credits, when positive, measure the total congestion credit to generation in an area. Generation congestion credits, when negative, measure the total congestion cost to generation in an area. Negative generation congestion credits result when generation is on the lower priced side of a constraint or constraints. For example, congestion across the AP South interface means lower prices in the western control zones and higher prices in the eastern and southern control zones. Generation in the western control zones will receive lower prices and incur a congestion charge (negative generation congestion credit). Generation in the eastern and southern control zones will receive higher prices and receive a congestion credit (positive generation congestion credit).

PJM congestion accounting nets load congestion payments against generation congestion credits by billing organization. The net congestion bill for a zone or constraint may be either positive or negative, depending on the relative size and sign of load congestion payments and generation congestion credits. When summed across a zone, the net congestion bill shows the overall congestion charge or credit for an area, not including explicit congestion, but the net congestion bill is not a good measure of whether load is paying higher prices in the form of congestion.

The AP Control Zone, the Dominion Control Zone and the ComEd Control Zone are good examples of how a positive net congestion bill can result from very different combinations of load payments and generation credits. The AP Control Zone had the highest congestion charges, $487.1 million, of any control zone in 2008. This positive total congestion cost was the result, in large part, of substantial negative generation congestion credits, which added to the total congestion costs for AP rather than offsetting the positive load congestion payments. The Dominion Control Zone had the second highest congestion charges, $322.6 million, of any control zone in 2008. The large positive congestion costs in the Dominion Control Zone were the result of large positive load congestion payments offset in small part by relatively low positive generation congestion credits. The ComEd Control Zone had the third highest congestion charges, $283.2 million, of any control zone in 2008. The large positive congestion costs in the ComEd Control Zone were the result of large negative load congestion payments offset by even larger negative generation congestion credits.

Table 7-16 Congestion cost summary (By control zone): Calendar year 2008

	Congestion Costs (Millions)								
	Day Ahead				Balancing				
Control Zone	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total
AECO	$111.1	$31.8	$1.2	$80.5	($12.9)	$8.1	($2.0)	($23.0)	$57.5
AEP	($367.1)	($671.0)	$15.7	$319.6	($85.2)	$4.0	($6.9)	($96.1)	$223.6
AP	$124.4	($391.6)	$38.7	$554.7	($13.6)	$21.5	($32.6)	($67.7)	$487.1
BGE	$314.3	$245.3	$3.2	$72.2	$10.1	($14.2)	($4.5)	$19.8	$92.0
ComEd	($480.9)	($820.9)	$4.8	$344.8	($54.9)	$0.4	($5.2)	($60.6)	$284.2
DAY	($45.5)	($56.5)	$0.2	$11.1	$3.5	$2.6	($0.3)	$0.6	$11.8
DLCO	($159.2)	($249.2)	$1.1	$91.2	($49.4)	$22.2	$0.3	($71.3)	$19.9
Dominion	$337.2	$5.2	$33.0	$364.9	($9.3)	($0.9)	($33.9)	($42.3)	$322.6
DPL	$149.5	$54.1	$1.1	$96.5	$8.0	$6.2	($1.8)	($0.1)	$96.4
External	($59.5)	($51.5)	$35.6	$27.5	($31.6)	($36.4)	($107.5)	($102.7)	($75.2)
JCPL	$260.6	$72.1	$9.1	$197.6	($0.0)	($0.4)	($8.9)	($8.5)	$189.0
Met-Ed	$104.9	$104.5	$3.3	$3.8	$2.3	$0.8	$10.4	$12.0	$15.7
PECO	$70.9	$118.1	$0.5	($46.8)	($0.5)	$15.5	($0.7)	($16.8)	($63.5)
PENELEC	($43.2)	($224.3)	$4.8	$186.0	($4.8)	$13.6	($1.4)	($19.9)	$166.1
Pepco	$642.4	$436.2	$8.4	$214.7	$6.6	($3.7)	($9.1)	$1.2	$215.9
PPL	$29.0	$39.9	$12.7	$1.8	$0.2	$5.6	($5.2)	($10.6)	($8.8)
PSEG	$287.3	$190.9	$33.3	$129.7	$5.2	$34.5	($27.9)	($57.3)	$72.5
RECO	$10.0	$0.1	$1.5	$11.4	$0.5	($0.2)	($2.2)	($1.5)	$9.9
Total	$1,286.1	($1,166.7)	$208.4	$2,661.2	($225.9)	$79.2	($239.5)	($544.6)	$2,116.6

Table 7-17 Congestion cost summary (By control zone): Calendar year 2007

	Congestion Costs (Millions)								
	Day Ahead				Balancing				
Control Zone	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total
AECO	$77.4	$31.9	$0.3	$45.8	$5.0	$3.3	($0.4)	$1.3	$47.1
AEP	($299.8)	($589.5)	$12.8	$302.6	($90.1)	$24.9	($2.0)	($117.1)	$185.5
AP	$92.8	($368.0)	$43.1	$503.9	($18.1)	$22.2	($15.0)	($55.3)	$448.6
BGE	$338.9	$290.2	$8.9	$57.7	$26.2	($12.1)	($12.5)	$25.8	$83.4
ComEd	($323.0)	($426.7)	($1.1)	$102.6	$44.1	($34.0)	$0.3	$78.3	$180.9
DAY	($36.3)	($54.1)	($0.1)	$17.8	($3.9)	$2.6	($0.0)	($6.6)	$11.2
DLCO	($134.9)	($220.2)	($0.0)	$85.2	($30.0)	$12.3	$0.0	($42.2)	$43.0
Dominion	$801.0	$525.1	$30.8	$306.7	$9.1	$3.4	($21.6)	($15.9)	$290.8
DPL	$108.8	$43.5	$1.3	$66.6	$11.5	$6.4	($2.2)	$2.9	$69.5
External	($69.6)	($17.6)	$11.0	($40.9)	($6.9)	($27.0)	($74.3)	($54.2)	($95.2)
JCPL	$214.4	$60.4	$4.0	$158.0	$4.1	($4.8)	($4.0)	$4.9	$162.9
Met-Ed	$106.0	$75.2	$5.1	$35.9	($4.9)	$6.1	$17.3	$6.3	$42.2
PECO	$70.6	$98.4	$0.7	($27.2)	($2.3)	$23.8	($0.9)	($27.0)	($54.2)
PENELEC	($72.3)	($237.3)	$4.5	$169.5	($5.3)	$14.0	($1.3)	($20.6)	$148.9
Pepco	$577.9	$439.4	$13.5	$152.0	$35.4	($20.8)	($18.6)	$37.7	$189.6
PPL	$26.8	$37.3	$7.9	($2.6)	$6.0	$9.8	$1.8	($2.0)	($4.6)
PSEG	$275.1	$165.3	$21.1	$130.9	$9.3	$29.3	($24.9)	($44.9)	$86.0
RECO	$10.2	$0.4	$0.5	$10.3	$0.4	$0.1	($0.6)	($0.3)	$9.9
Total	$1,764.0	($146.4)	$164.2	$2,074.6	($10.5)	$59.5	($158.9)	($228.9)	$1,845.7

Details of Regional and Zonal Congestion

Constraints were examined by zone and categorized by their effect on regions. Zones correspond to regulated utility franchise areas. Regions generally comprise two or more zones. PJM is comprised of three regions: the PJM Mid-Atlantic Region with 11 control zones (the AECO, BGE, DPL, JCPL, Met-Ed, PECO, PENELEC, Pepco, PPL, PSEG and RECO control zones); the PJM Western Region with five control zones (the AP, ComEd, AEP, DLCO and DAY control zones); and the PJM Southern Region with one control zone (the Dominion Control Zone).

Table 7-18 through Table 7-51 present the top constraints affecting zonal congestion costs by control zone and demonstrate the influence of individual constraints on zonal congestion costs in calendar years 2007 and 2008. For each of these constraints, the zonal cost impacts are decomposed into their Day-Ahead Energy Market and balancing market components. Total congestion costs are the sum of the day-ahead and balancing congestion cost components. Total congestion costs associated with a given constraint may be positive or negative in value. The top constraints affecting zonal congestion costs are presented by constraint, in descending order of the absolute value of total congestion costs. Both day-ahead and real-time, congestion-event hours are presented for each of the highlighted constraints. Constraints can have wide-ranging effects, influencing prices across multiple zones.

Mid-Atlantic Region Congestion-Event Summaries

AECO Control Zone

Table 7-18 and Table 7-19 show the constraints with the largest impacts on total congestion cost in the AECO Control Zone for 2008 and 2007, respectively. In 2008, the Monroe transformer and West and AP South interface constraints were the largest contributors to positive congestion while the Atlantic – Larrabee line contributed to negative congestion. All of these constraints are located outside of the AECO Control Zone except for the Monroe transformer. In 2007, the Beckett – Paulsboro line and Bedington – Black Oak interface constraints had been the largest contributors to positive congestion while the Branchburg – Readington and the Atlantic – Larrabee constraints contributed to negative congestion.

Table 7-18 AECO Control Zone top congestion cost impacts (By facility): Calendar year 2008

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Monroe	Transformer	AECO	$34.4	$3.6	$0.2	$31.0	($14.5)	$4.3	($0.7)	($19.5)	$11.5	815	247
West	Interface	500	$12.6	$5.6	$0.1	$7.2	$0.5	($0.0)	($0.1)	$0.4	$7.6	1,690	385
AP South	Interface	500	$13.0	$5.6	$0.3	$7.7	$0.1	$0.1	($0.2)	($0.1)	$7.6	3,572	997
Cloverdale - Lexington	Line	AEP	$8.0	$4.2	$0.0	$3.8	$0.7	($0.1)	($0.1)	$0.7	$4.5	3,529	1,739
Atlantic - Larrabee	Line	JCPL	($6.5)	($2.9)	($0.0)	($3.6)	($0.4)	$0.4	$0.0	($0.8)	($4.4)	1,556	380
Kammer	Transformer	500	$7.2	$3.4	$0.1	$3.9	$0.4	$0.1	($0.1)	$0.3	$4.1	3,069	1,567
Churchtown	Transformer	AECO	($0.3)	($3.0)	$0.0	$2.7	$0.4	$0.3	($0.0)	$0.1	$2.8	179	104
East	Interface	500	$5.3	$2.8	$0.0	$2.6	$0.0	($0.0)	$0.0	$0.0	$2.6	758	12
Quinton - Roadstown	Line	AECO	$6.3	$1.0	$0.0	$5.3	($1.3)	$1.4	($0.1)	($2.8)	$2.5	288	124
5004/5005 Interface	Interface	500	$4.2	$1.8	$0.0	$2.3	$0.1	$0.0	($0.0)	$0.0	$2.4	736	411
Central	Interface	500	$4.5	$2.4	$0.0	$2.1	$0.0	($0.0)	($0.0)	$0.0	$2.1	726	42
Sammis - Wylie Ridge	Line	AP	$2.4	$1.3	$0.0	$1.1	$0.6	$0.1	($0.1)	$0.4	$1.5	1,915	1,239
Dickerson - Plesant View	Line	Pepco	$2.6	$1.3	$0.0	$1.3	$0.0	($0.0)	($0.0)	$0.0	$1.4	844	218
Mount Storm - Pruntytown	Line	AP	$2.7	$1.2	$0.2	$1.6	($0.1)	$0.0	($0.2)	($0.3)	$1.4	2,559	722
Bedington - Black Oak	Interface	500	$2.5	$1.2	$0.0	$1.3	$0.0	$0.0	($0.0)	($0.0)	$1.3	1,384	279

Table 7-19 AECO Control Zone top congestion cost impacts (By facility): Calendar year 2007

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Beckett - Paulsboro	Line	AECO	$21.5	$5.7	$0.1	$15.9	($2.3)	($0.1)	($0.0)	($2.2)	$13.7	768	417
Bedington - Black Oak	Interface	500	$17.9	$10.2	$0.0	$7.8	$1.6	($0.0)	($0.0)	$1.6	$9.4	5,493	1,836
Branchburg - Readington	Line	PSEG	($9.3)	($5.5)	($0.0)	($3.9)	($1.4)	$0.4	$0.1	($1.7)	($5.6)	2,324	721
5004/5005 Interface	Interface	500	$10.8	$5.9	$0.1	$4.9	$0.4	($0.0)	($0.0)	$0.4	$5.3	1,512	386
Cloverdale - Lexington	Line	AEP	$8.8	$5.3	$0.0	$3.6	$1.6	$0.1	($0.0)	$1.4	$5.0	3,704	1,885
Kammer	Transformer	500	$6.3	$3.6	$0.0	$2.8	$0.8	$0.1	($0.0)	$0.7	$3.5	2,005	947
Central	Interface	500	$6.3	$3.7	$0.0	$2.7	($0.0)	($0.0)	($0.0)	$0.0	$2.7	1,334	25
Wylie Ridge	Transformer	AP	$4.4	$2.4	$0.1	$2.1	$0.7	($0.0)	($0.2)	$0.5	$2.6	1,486	685
Churchtown	Transformer	AECO	($0.7)	($3.4)	($0.2)	$2.6	$0.3	$0.6	$0.2	($0.1)	$2.5	328	194
Atlantic - Larrabee	Line	JCPL	($2.8)	($1.2)	($0.0)	($1.5)	($0.3)	$0.2	$0.0	($0.5)	($2.0)	680	134
AP South	Interface	500	$3.0	$1.5	$0.0	$1.5	$0.2	$0.0	($0.1)	$0.2	$1.7	706	133
West	Interface	500	$1.8	$1.0	$0.0	$0.8	$0.5	$0.1	($0.0)	$0.4	$1.2	359	338
East	Interface	500	$1.9	$1.0	$0.0	$1.0	$0.0	($0.0)	$0.0	$0.0	$1.0	304	5
Cardiff	Transformer	AECO	$0.4	$0.1	$0.0	$0.4	$0.6	$0.1	($0.0)	$0.5	$0.9	26	27
Carlls Corner - Sherman Ave	Line	AECO	$0.4	$0.0	$0.0	$0.4	($0.4)	$0.8	($0.0)	($1.2)	($0.8)	182	82

BGE Control Zone

Table 7-20 and Table 7-21 show the constraints with the largest impacts on total congestion cost in the BGE Control Zone for 2008 and 2007, respectively. In 2008, the AP South interface constraints was the largest contributor to positive congestion. In 2007, the Bedington – Black Oak interface constraint had been the largest contributor to positive congestion while the Branchburg – Readington constraint contributed to negative congestion.

Table 7-20 BGE Control Zone top congestion cost impacts (By facility): Calendar year 2008

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
AP South	Interface	500	$86.9	$68.9	$0.6	$18.6	$4.6	($3.8)	($0.9)	$7.6	$26.2	3,572	997
Mount Storm - Pruntytown	Line	AP	$38.9	$32.3	$0.3	$6.9	$0.1	($2.3)	($0.1)	$2.3	$9.2	2,559	722
West	Interface	500	$21.7	$15.9	$0.4	$6.2	$1.1	($0.8)	($0.6)	$1.3	$7.5	1,690	385
Kammer	Transformer	500	$18.9	$15.4	$0.4	$4.0	$1.2	($1.4)	($0.4)	$2.2	$6.2	3,069	1,567
Dickerson - Plesant View	Line	Pepco	$12.5	$8.1	$0.4	$4.8	$0.7	($0.5)	($0.2)	$1.0	$5.8	844	218
Aqueduct - Doubs	Line	AP	$12.2	$7.0	$0.0	$5.2	($0.0)	($0.0)	($0.0)	$0.0	$5.2	307	7
Pumphrey - Westport	Line	Pepco	$4.3	($0.4)	$0.0	$4.7	$0.0	$0.0	$0.0	$0.0	$4.7	1,092	0
Bedington - Black Oak	Interface	500	$24.8	$22.7	$0.3	$2.4	$1.0	($0.6)	($0.1)	$1.5	$3.9	1,384	279
Conastone	Transformer	BGE	$4.4	$1.4	($0.0)	$3.1	$0.1	($0.0)	$0.0	$0.1	$3.2	95	15
Sammis - Wylie Ridge	Line	AP	$5.2	$4.3	$0.1	$1.0	$1.1	($0.8)	($0.4)	$1.5	$2.5	1,915	1,239
Mount Storm	Transformer	AP	$12.7	$11.0	$0.1	$1.8	($0.3)	($1.0)	($0.1)	$0.7	$2.5	935	373
Green Street - Westport	Line	BGE	$2.3	($0.0)	$0.0	$2.3	$0.0	$0.0	$0.0	$0.0	$2.3	346	0
Cloverdale - Lexington	Line	AEP	$40.5	$41.6	$0.5	($0.7)	$2.1	($1.0)	($0.4)	$2.8	$2.2	3,529	1,739
5004/5005 Interface	Interface	500	$3.4	$1.9	$0.1	$1.6	$0.2	($0.3)	($0.1)	$0.3	$1.9	736	411
Brandon Shores - Riverside	Line	BGE	$1.3	($0.8)	$0.0	$2.1	($0.6)	$0.2	($0.0)	($0.9)	$1.2	150	56

Table 7-21 BGE Control Zone top congestion cost impacts (By facility): Calendar year 2007

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Bedington - Black Oak	Interface	500	$190.5	$165.8	$4.1	$28.8	$11.8	($5.2)	($4.0)	$13.0	$41.8	5,493	1,836
Branchburg - Readington	Line	PSEG	($25.7)	($21.0)	($0.6)	($5.3)	($1.0)	$0.9	$0.6	($1.3)	($6.6)	2,324	721
Conastone	Transformer	BGE	$10.2	$4.5	($0.1)	$5.6	$0.8	$0.0	$0.0	$0.8	$6.4	172	55
Kammer	Transformer	500	$22.9	$18.6	$1.0	$5.3	$1.4	($0.8)	($1.2)	$1.0	$6.3	2,005	947
AP South	Interface	500	$22.3	$18.5	$0.4	$4.2	$1.4	($0.3)	($0.2)	$1.4	$5.6	706	133
5004/5005 Interface	Interface	500	$12.4	$7.8	$0.7	$5.4	$0.1	($0.2)	($0.3)	($0.0)	$5.4	1,512	386
Cloverdale - Lexington	Line	AEP	$55.9	$59.0	$1.8	($1.3)	$4.6	($3.0)	($1.7)	$5.9	$4.6	3,704	1,885
Wylie Ridge	Transformer	AP	$11.5	$9.3	$0.6	$2.8	$0.6	($0.5)	($0.8)	$0.4	$3.2	1,486	685
Brunner Island - Yorkana	Line	Met-Ed	$4.8	$3.3	$0.0	$1.5	$0.5	($0.3)	($0.2)	$0.6	$2.1	172	196
Bedington	Transformer	AP	$8.0	$6.7	$0.2	$1.6	$0.2	($0.2)	($0.2)	$0.2	$1.8	928	429
Aqueduct - Doubs	Line	AP	$4.3	$2.8	$0.0	$1.5	$0.0	($0.0)	($0.0)	$0.1	$1.6	262	21
West	Interface	500	$4.6	$3.3	$0.3	$1.7	$0.5	($0.6)	($1.4)	($0.3)	$1.4	359	338
Doubs	Transformer	AP	$3.0	$1.7	$0.0	$1.2	$0.0	($0.2)	($0.1)	$0.1	$1.3	135	99
Bedington - Nipetown	Line	AP	$2.9	$2.1	$0.1	$0.9	$0.2	($0.2)	($0.1)	$0.3	$1.2	841	175
Mount Storm - Pruntytown	Line	AP	$0.5	$0.4	$0.0	$0.0	$0.7	($0.4)	($0.1)	$1.1	$1.1	33	151

DPL Control Zone

Table 7-22 and Table 7-23 show the constraints with the largest impacts on total congestion cost in the DPL Control Zone for 2008 and 2007, respectively. In 2008, the North Seaford – Pine Street line and the West interface constraints were the largest contributors to positive congestion while the Atlantic – Larrabee and the Branchburg – Readington constraints contributed to negative congestion. In 2007, the Bedington – Black Oak and Cloverdale – Lexington constraints had been the largest contributors to positive congestion while the Branchburg – Readington constraint contributed to negative congestion.

Table 7-22 DPL Control Zone top congestion cost impacts (By facility): Calendar year 2008

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
North Seaford - Pine Street	Line	DPL	$21.2	$5.4	$0.1	$16.0	($1.0)	($0.6)	($0.1)	($0.6)	$15.4	690	142
West	Interface	500	$20.0	$7.3	$0.2	$12.9	$1.0	$1.0	($0.0)	$0.0	$12.9	1,690	385
AP South	Interface	500	$23.0	$11.0	$0.2	$12.2	$1.5	$1.2	($0.1)	$0.2	$12.4	3,572	997
Cloverdale - Lexington	Line	AEP	$14.4	$4.7	$0.1	$9.9	$1.0	($0.0)	($0.1)	$0.9	$10.8	3,529	1,739
Kammer	Transformer	500	$12.1	$4.3	$0.1	$7.9	$1.1	$0.7	($0.1)	$0.3	$8.2	3,069	1,567
East	Interface	500	$9.2	$3.4	$0.1	$5.9	$0.0	($0.0)	($0.0)	$0.0	$5.9	758	12
Central	Interface	500	$7.6	$3.4	$0.0	$4.3	$0.1	($0.0)	($0.0)	$0.1	$4.3	726	42
5004/5005 Interface	Interface	500	$6.6	$2.6	$0.0	$4.0	$0.6	$0.6	($0.1)	($0.1)	$4.0	736	411
Mount Storm - Pruntytown	Line	AP	$5.6	$2.3	$0.1	$3.5	$0.3	$0.2	($0.1)	$0.0	$3.5	2,559	722
Sammis - Wylie Ridge	Line	AP	$4.3	$1.2	$0.0	$3.1	$1.0	$0.6	($0.1)	$0.2	$3.3	1,915	1,239
Bedington - Black Oak	Interface	500	$5.1	$2.0	$0.0	$3.1	$0.2	$0.0	($0.0)	$0.1	$3.2	1,384	279
Atlantic - Larrabee	Line	JCPL	($4.4)	($1.9)	($0.0)	($2.6)	($0.5)	($0.1)	$0.1	($0.4)	($2.9)	1,556	380
Dickerson - Plesant View	Line	Pepco	$4.7	$2.2	$0.1	$2.6	$0.1	($0.0)	($0.1)	($0.0)	$2.6	844	218
Red Lion At5n	Transformer	DPL	$3.8	$1.4	$0.1	$2.5	$0.0	($0.1)	$0.0	$0.1	$2.5	53	3
Branchburg - Readington	Line	PSEG	($3.3)	($1.4)	($0.1)	($2.0)	($0.2)	$0.3	$0.1	($0.4)	($2.4)	1,121	271

Table 7-23 DPL Control Zone top congestion cost impacts (By facility): Calendar year 2007

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Bedington - Black Oak	Interface	500	$36.6	$15.8	$0.3	$21.1	$3.5	$0.9	($0.2)	$2.3	$23.4	5,493	1,836
Cloverdale - Lexington	Line	AEP	$16.8	$6.1	$0.2	$10.9	$2.5	$0.2	($0.2)	$2.1	$13.0	3,704	1,885
Branchburg - Readington	Line	PSEG	($17.8)	($7.5)	($0.1)	($10.4)	($2.1)	($0.2)	$0.3	($1.6)	($12.0)	2,324	721
5004/5005 Interface	Interface	500	$18.4	$8.5	$0.2	$10.1	$0.7	$0.5	($0.1)	$0.1	$10.2	1,512	386
Kammer	Transformer	500	$11.3	$4.9	$0.2	$6.6	$1.5	$0.6	($0.2)	$0.7	$7.3	2,005	947
Central	Interface	500	$11.5	$5.2	$0.1	$6.5	$0.0	($0.0)	($0.0)	$0.0	$6.5	1,334	25
Wylie Ridge	Transformer	AP	$7.8	$3.2	$0.1	$4.7	$1.0	$0.2	($0.1)	$0.7	$5.4	1,486	685
AP South	Interface	500	$5.7	$2.5	$0.0	$3.2	$0.4	$0.1	($0.0)	$0.3	$3.6	706	133
West	Interface	500	$3.3	$1.4	$0.0	$1.9	$1.1	$0.1	($0.2)	$0.7	$2.7	359	338
East	Interface	500	$3.7	$1.4	$0.0	$2.2	$0.0	($0.0)	($0.0)	$0.0	$2.3	304	5
North Seaford	Transformer	DPL	$2.4	$0.4	$0.0	$2.0	$0.1	$0.0	$0.0	$0.0	$2.0	149	7
Atlantic - Larrabee	Line	JCPL	($2.2)	($1.0)	($0.0)	($1.3)	($0.2)	$0.3	$0.1	($0.3)	($1.6)	680	134
Elrama - Mitchell	Line	AP	$2.1	$0.9	$0.0	$1.2	$0.3	$0.0	($0.0)	$0.2	$1.4	1,883	784
Conastone	Transformer	BGE	($2.9)	($1.4)	($0.0)	($1.5)	($0.2)	($0.3)	$0.0	$0.1	($1.4)	172	55
Cedar Grove - Roseland	Line	PSEG	($2.1)	($0.7)	($0.0)	($1.4)	($0.0)	($0.0)	$0.0	($0.0)	($1.4)	1,677	133

JCPL Control Zone

Table 7-24 and Table 7-25 show the constraints with the largest impacts on total congestion cost in the JCPL Control Zone for 2008 and 2007, respectively. In both 2007 and 2008, the Atlantic – Larrabee and Branchburg – Readington constraints were the largest contributors to positive congestion while the Cedar Grove – Roseland constraint contributed to negative congestion.

Table 7-24 JCPL Control Zone top congestion cost impacts (By facility): Calendar year 2008

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Atlantic - Larrabee	Line	JCPL	$47.5	$2.2	$2.2	$47.5	($3.0)	$2.8	($2.4)	($8.2)	$39.3	1,556	380
Branchburg - Readington	Line	PSEG	$27.7	$4.5	$2.2	$25.4	($2.2)	($0.8)	($1.8)	($3.3)	$22.2	1,121	271
West	Interface	500	$29.5	$11.9	$0.3	$17.9	$0.1	($0.2)	($0.6)	($0.4)	$17.6	1,690	385
Cloverdale - Lexington	Line	AEP	$18.8	$5.2	$0.7	$14.4	$0.6	($0.2)	($0.5)	$0.3	$14.6	3,529	1,739
AP South	Interface	500	$22.6	$9.2	$0.8	$14.1	$0.2	($0.4)	($1.0)	($0.4)	$13.7	3,572	997
Kammer	Transformer	500	$18.0	$6.3	$0.4	$12.2	$0.5	($0.0)	($0.4)	$0.2	$12.4	3,069	1,567
Central	Interface	500	$12.2	$3.6	$0.5	$9.0	$0.0	($0.1)	($0.0)	$0.0	$9.1	726	42
Branchburg - Flagtown	Line	PSEG	$11.2	$3.0	$0.1	$8.3	$1.4	$0.6	($0.1)	$0.7	$9.0	284	61
5004/5005 Interface	Interface	500	$11.7	$4.2	$0.3	$7.8	$0.4	($0.1)	($0.2)	$0.3	$8.1	736	411
East	Interface	500	$11.4	$3.5	$0.0	$8.0	($0.0)	($0.0)	($0.0)	($0.0)	$7.9	758	12
Cedar Grove - Roseland	Line	PSEG	($9.4)	($1.7)	($0.2)	($7.9)	($0.4)	($0.4)	$0.1	$0.1	($7.8)	627	168
Buckingham - Pleasant Valley	Line	PECO	$10.7	$3.8	$0.2	$7.1	($0.1)	($0.1)	($0.1)	($0.1)	$6.9	647	74
Sammis - Wylie Ridge	Line	AP	$5.9	$1.8	$0.1	$4.2	$0.6	$0.0	($0.3)	$0.3	$4.4	1,915	1,239
Dickerson - Plesant View	Line	Pepco	$6.0	$2.3	$0.2	$3.9	$0.0	($0.2)	($0.1)	$0.1	$4.0	844	218
Redoak - Sayreville	Line	JCPL	$0.2	($2.3)	$0.0	$2.5	$0.2	($0.5)	$0.4	$1.1	$3.6	254	30

Table 7-25 JCPL Control Zone top congestion cost impacts (By facility): Calendar year 2007

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Branchburg - Readington	Line	PSEG	$31.8	$4.1	$1.5	$29.2	($3.5)	($5.8)	($1.9)	$0.4	$29.6	2,324	721
Atlantic - Larrabee	Line	JCPL	$25.2	$2.3	$0.5	$23.4	$0.0	$0.9	($0.3)	($1.1)	$22.3	680	134
Bedington - Black Oak	Interface	500	$32.8	$12.8	$0.6	$20.6	$0.3	($0.1)	($0.5)	($0.0)	$20.6	5,493	1,836
5004/5005 Interface	Interface	500	$29.2	$10.7	$0.4	$19.0	$0.7	($0.2)	($0.1)	$0.9	$19.8	1,512	386
Cloverdale - Lexington	Line	AEP	$21.7	$6.4	$0.4	$15.8	$0.7	($0.1)	($0.3)	$0.5	$16.3	3,704	1,885
Kammer	Transformer	500	$16.2	$5.9	$0.2	$10.5	$0.7	($0.1)	($0.1)	$0.6	$11.1	2,005	947
Central	Interface	500	$15.7	$5.1	$0.1	$10.7	$0.0	($0.0)	($0.0)	$0.1	$10.8	1,334	25
Cedar Grove - Roseland	Line	PSEG	($12.9)	($3.3)	($0.8)	($10.4)	($0.2)	($0.1)	$0.3	$0.1	($10.3)	1,677	133
Branchburg - Flagtown	Line	PSEG	$16.4	$6.7	$0.2	$10.0	$0.6	$0.4	($0.4)	($0.1)	$9.8	580	104
Wylie Ridge	Transformer	AP	$11.2	$4.2	$0.1	$7.1	$0.8	$0.1	($0.1)	$0.6	$7.7	1,486	685
AP South	Interface	500	$6.2	$2.6	$0.2	$3.8	$0.1	$0.0	($0.1)	$0.0	$3.8	706	133
Redoak - Sayreville	Line	JCPL	$0.4	($2.2)	($0.0)	$2.6	($0.1)	$0.3	$1.4	$1.1	$3.6	139	33
West	Interface	500	$4.6	$1.7	$0.0	$2.9	$0.6	($0.2)	($0.1)	$0.7	$3.6	359	338
Unclassified	Unclassified	Unclassified	$3.2	$0.3	$0.0	$2.9	$0.0	$0.0	$0.0	$0.0	$2.9	NA	NA
East	Interface	500	$4.2	$1.5	$0.0	$2.7	($0.0)	($0.0)	($0.0)	$0.0	$2.7	304	5

Met-Ed Control Zone

Table 7-26 and Table 7-27 show the constraints with the largest impacts on total congestion cost in the Met-Ed Control Zone for 2008 and 2007, respectively. In 2008, the AP South and Cloverdale – Lexington constraints were the largest contributors to positive congestion while the Conemaugh – Hunterstown and West interface constraints contributed to negative congestion. In 2007, the Brunner Island - Yorkana and Bedington – Black Oak constraints had been the largest contributors to positive congestion while the Branchburg – Readington line and Central interface constraints contributed to negative congestion.

Table 7-26 Met-Ed Control Zone top congestion cost impacts (By facility): Calendar year 2008

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
AP South	Interface	500	$17.9	$19.3	$0.7	($0.8)	$0.5	($0.2)	$3.4	$4.1	$3.3	3,572	997
Cloverdale - Lexington	Line	AEP	$12.5	$11.7	$0.7	$1.5	$0.2	$0.3	$0.5	$0.4	$1.9	3,529	1,739
Bedington	Transformer	AP	$1.8	$0.3	$0.0	$1.5	($0.0)	$0.0	$0.2	$0.2	$1.7	1,192	299
Bedington - Black Oak	Interface	500	$4.3	$3.5	$0.1	$0.9	$0.0	($0.0)	$0.6	$0.7	$1.6	1,384	279
Kammer	Transformer	500	$10.4	$11.1	$0.5	($0.2)	$0.2	($0.3)	$1.3	$1.8	$1.5	3,069	1,567
Brunner Island - Yorkana	Line	Met-Ed	$0.5	($0.9)	$0.0	$1.4	$0.1	$0.1	($0.0)	($0.0)	$1.4	57	27
Conemaugh - Hunterstown	Line	500	$0.6	$1.5	$0.0	($0.9)	($0.1)	($0.1)	($0.4)	($0.3)	($1.2)	62	98
Middletown Jct	Transformer	Met-Ed	$1.0	($0.1)	$0.0	$1.1	$0.0	$0.0	$0.0	$0.0	$1.1	59	1
Collins - Middletown Jct	Line	Met-Ed	$1.0	($0.0)	$0.0	$1.1	($0.0)	$0.2	$0.1	($0.1)	$1.0	272	31
West	Interface	500	$15.1	$18.3	$0.6	($2.6)	$0.3	($0.2)	$1.3	$1.8	($0.9)	1,690	385
Conastone	Transformer	BGE	$0.4	($0.3)	($0.1)	$0.7	$0.0	$0.1	$0.1	$0.0	$0.7	95	15
East Towanda	Transformer	PENELEC	$0.3	$0.4	$0.0	$0.0	$0.1	($0.1)	$0.4	$0.6	$0.6	803	306
Aqueduct - Doubs	Line	AP	($0.8)	($0.2)	$0.0	($0.6)	$0.0	$0.0	$0.0	$0.0	($0.6)	307	7
Harwood - Susquehanna	Line	PPL	$1.2	$0.4	$0.0	$0.8	$0.0	$0.3	($0.0)	($0.2)	$0.6	117	99
Mount Storm - Pruntytown	Line	AP	$4.6	$4.4	$0.2	$0.4	($0.0)	$0.0	$0.2	$0.2	$0.6	2,559	722

Table 7-27 Met-Ed Control Zone top congestion cost impacts (By facility): Calendar year 2007

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Brunner Island - Yorkana	Line	Met-Ed	$4.1	($3.3)	$0.0	$7.4	($0.3)	($0.3)	$0.6	$0.6	$8.1	172	196
Bedington - Black Oak	Interface	500	$29.5	$26.1	$1.8	$5.2	($1.6)	$0.3	$4.1	$2.3	$7.5	5,493	1,836
Hunterstown	Transformer	Met-Ed	$7.4	$1.4	$0.3	$6.3	($0.4)	$0.7	$1.0	($0.1)	$6.2	345	139
Jackson	Transformer	Met-Ed	$5.3	($0.1)	$0.1	$5.5	($0.5)	$1.4	$1.1	($0.7)	$4.8	155	114
Gardners - Hunterstown	Line	Met-Ed	$2.1	($1.2)	$0.1	$3.4	($0.4)	$0.4	$0.4	($0.4)	$3.0	953	271
5004/5005 Interface	Interface	500	$15.1	$13.7	$0.6	$2.0	($0.3)	$0.4	$1.3	$0.5	$2.5	1,512	386
Kammer	Transformer	500	$9.5	$9.9	$0.9	$0.5	($0.4)	($0.2)	$1.7	$1.5	$2.0	2,005	947
Bedington	Transformer	AP	$1.8	$0.6	$0.0	$1.3	($0.1)	$0.1	$0.8	$0.6	$1.9	928	429
Branchburg - Readington	Line	PSEG	($10.8)	($8.3)	($0.0)	($2.5)	$1.3	$0.3	$0.1	$1.0	($1.5)	2,324	721
Conastone	Transformer	BGE	$0.1	($0.9)	$0.0	$1.1	$0.0	$0.2	($0.1)	($0.2)	$0.9	172	55
Cloverdale - Lexington	Line	AEP	$14.8	$12.9	$0.2	$2.1	($1.2)	$0.5	$0.4	($1.3)	$0.8	3,704	1,885
Central	Interface	500	$4.2	$5.0	$0.1	($0.7)	($0.0)	($0.0)	$0.0	$0.0	($0.7)	1,334	25
AP South	Interface	500	$4.5	$4.7	$0.3	$0.1	($0.0)	$0.2	$0.9	$0.6	$0.7	706	133
MAAC - Scarcity	Interface	500	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.6	$0.6	$0.6	0	3
Doubs	Transformer	AP	$0.5	$0.2	$0.1	$0.4	($0.1)	$0.0	$0.2	$0.2	$0.5	135	99

PECO Control Zone

Table 7-28 and Table 7-29 show the constraints with the largest impacts on total congestion cost in the PECO Control Zone for 2008 and 2007, respectively. In 2008, the East interface was the largest contributor to positive congestion while the AP South and West interface constraints were the largest contributors to negative congestion. In 2007, the Branchburg – Readington and East interface constraints were the largest contributors to positive congestion while the Bedington – Black Oak and Cloverdale – Lexington constraints contributed to negative congestion.

Table 7-28 PECO Control Zone top congestion cost impacts (By facility): Calendar year 2008

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
AP South	Interface	500	$8.2	$27.7	$0.0	($19.5)	$0.0	$1.2	$0.0	($1.2)	($20.7)	3,572	997
West	Interface	500	$9.4	$23.1	$0.1	($13.6)	$0.1	$1.7	$0.0	($1.5)	($15.1)	1,690	385
East	Interface	500	$10.0	$0.4	($0.0)	$9.7	($0.0)	($0.1)	$0.0	$0.1	$9.7	758	12
Kammer	Transformer	500	$6.7	$13.9	$0.0	($7.1)	$0.4	$1.1	$0.0	($0.6)	($7.7)	3,069	1,567
Cloverdale - Lexington	Line	AEP	$8.6	$14.5	$0.1	($5.8)	$0.1	$1.4	($0.0)	($1.4)	($7.1)	3,529	1,739
Mount Storm - Pruntytown	Line	AP	$1.4	$6.8	$0.0	($5.4)	($0.1)	$0.2	($0.0)	($0.3)	($5.7)	2,559	722
Bedington - Black Oak	Interface	500	$1.6	$6.2	$0.0	($4.6)	($0.0)	$0.2	$0.0	($0.1)	($4.7)	1,384	279
5004/5005 Interface	Interface	500	$3.5	$7.3	$0.0	($3.8)	$0.2	$0.7	($0.0)	($0.5)	($4.3)	736	411
Dickerson - Plesant View	Line	Pepco	$2.1	$6.0	$0.0	($3.9)	($0.1)	$0.0	$0.0	($0.1)	($4.0)	844	218
Sammis - Wylie Ridge	Line	AP	$2.8	$4.1	$0.0	($1.2)	($0.1)	$1.8	$0.0	($1.9)	($3.1)	1,915	1,239
Branchburg - Readington	Line	PSEG	($1.9)	($4.6)	($0.0)	$2.6	($0.0)	$0.2	($0.0)	($0.3)	$2.4	1,121	271
Conastone	Transformer	BGE	($0.2)	($2.4)	($0.0)	$2.2	$0.0	($0.0)	($0.0)	$0.0	$2.3	95	15
Unclassified	Unclassified	Unclassified	$2.0	$0.2	$0.0	$1.8	($0.0)	$0.0	$0.0	($0.0)	$1.8	NA	NA
Bradford - Planebrook	Line	PECO	$0.7	($1.1)	($0.0)	$1.8	$0.0	$0.1	$0.0	($0.1)	$1.7	124	24
Whitpain	Transformer	PECO	$3.8	($1.4)	$0.1	$5.2	($0.4)	$2.8	($0.3)	($3.5)	$1.7	89	68

Table 7-29 PECO Control Zone top congestion cost impacts (By facility): Calendar year 2007

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Bedington - Black Oak	Interface	500	$17.0	$38.1	$0.2	($20.9)	($1.4)	$5.6	$0.0	($6.9)	($27.9)	5,493	1,836
Cloverdale - Lexington	Line	AEP	$11.9	$15.9	$0.1	($3.9)	($0.2)	$4.7	($0.1)	($5.0)	($8.9)	3,704	1,885
5004/5005 Interface	Interface	500	$13.5	$19.6	$0.1	($6.0)	($0.0)	$2.3	($0.0)	($2.4)	($8.3)	1,512	386
Branchburg - Readington	Line	PSEG	($12.9)	($17.5)	($0.0)	$4.6	$1.3	($2.2)	($0.2)	$3.2	$7.8	2,324	721
Kammer	Transformer	500	$8.5	$11.9	$0.1	($3.3)	($0.4)	$3.3	($0.1)	($3.8)	($7.1)	2,005	947
East	Interface	500	$4.7	($0.5)	($0.0)	$5.2	($0.0)	($0.0)	$0.0	($0.0)	$5.2	304	5
AP South	Interface	500	$2.4	$6.5	$0.0	($4.1)	($0.1)	$0.9	$0.0	($1.0)	($5.0)	706	133
Wylie Ridge	Transformer	AP	$5.4	$7.7	$0.0	($2.2)	($0.3)	$2.2	($0.1)	($2.6)	($4.8)	1,486	685
Plymouth Meeting - Whitpain	Line	PECO	$6.2	$1.4	$0.0	$4.8	($0.1)	$0.6	$0.0	($0.6)	$4.1	55	34
Central	Interface	500	$7.4	$11.2	$0.1	($3.7)	($0.0)	$0.1	($0.0)	($0.1)	($3.8)	1,334	25
West	Interface	500	$1.9	$3.2	$0.0	($1.3)	($0.5)	$1.8	($0.0)	($2.3)	($3.6)	359	338
Conastone	Transformer	BGE	($0.4)	($3.2)	($0.0)	$2.8	$0.3	$0.1	$0.0	$0.3	$3.1	172	55
Elrama - Mitchell	Line	AP	$1.2	$2.2	$0.0	($0.9)	$0.0	$0.7	($0.0)	($0.7)	($1.6)	1,883	784
Loudoun - Morrisville	Line	Dominion	$0.3	$0.6	$0.0	($0.3)	($0.3)	$0.9	($0.0)	($1.2)	($1.5)	74	93
Brunner Island - Yorkana	Line	Met-Ed	($0.9)	($1.2)	($0.0)	$0.3	$0.3	($0.8)	$0.0	$1.0	$1.4	172	196

PENELEC Control Zone

Table 7-30 and Table 7-31 show the constraints with the largest impacts on total congestion cost in the PENELEC Control Zone for 2008 and 2007, respectively. In 2008, the AP South and West interface constraints, along with the Mount Storm – Pruntytown constraint, contributed to positive congestion while the Kammer transformer and Sammis – Wylie Ridge constraints contributed to negative congestion. In 2007, the Bedington – Black Oak and 5004/5005 interface constraints were the largest contributors to positive congestion while the Wylie Ridge and Kammer transformer constraints contributed to negative congestion.

Table 7-30 PENELEC Control Zone top congestion cost impacts (By facility): Calendar year 2008

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
AP South	Interface	500	($35.4)	($69.6)	$0.3	$34.5	$3.1	$0.7	$0.7	$3.1	$37.6	3,572	997
West	Interface	500	($7.9)	($46.5)	($0.3)	$38.2	$0.1	$1.5	$0.3	($1.1)	$37.1	1,690	385
Mount Storm - Pruntytown	Line	AP	($27.4)	($55.5)	$0.1	$28.1	$0.9	($0.3)	$0.0	$1.2	$29.3	2,559	722
Kammer	Transformer	500	$10.1	$33.1	$0.8	($22.2)	($0.8)	($1.3)	$0.2	$0.7	($21.6)	3,069	1,567
Bedington - Black Oak	Interface	500	($16.6)	($37.5)	$0.1	$20.9	$0.6	$0.3	$0.1	$0.4	$21.4	1,384	279
5004/5005 Interface	Interface	500	($3.8)	($23.7)	($0.1)	$19.8	($0.7)	$1.3	$0.1	($1.8)	$18.0	736	411
Seward	Transformer	PENELEC	$33.2	$20.4	$0.1	$12.8	$0.9	$1.0	($0.1)	($0.1)	$12.7	363	50
Sammis - Wylie Ridge	Line	AP	$6.2	$17.6	$0.6	($10.8)	($0.4)	($0.4)	($1.1)	($1.1)	($11.8)	1,915	1,239
Mount Storm	Transformer	AP	($8.2)	($17.9)	$0.1	$9.7	($0.8)	$0.0	($0.0)	($0.9)	$8.8	935	373
Krendale - Seneca	Line	AP	$4.7	$13.2	$0.3	($8.3)	$0.0	$0.0	($0.0)	$0.0	($8.2)	1,389	24
Central	Interface	500	($0.5)	($8.6)	($0.0)	$8.0	$0.0	($0.0)	$0.0	$0.0	$8.0	726	42
East Towanda	Transformer	PENELEC	$14.1	($8.8)	$1.0	$23.8	($9.2)	$8.4	($0.5)	($18.1)	$5.7	803	306
East	Interface	500	($1.4)	($6.3)	($0.1)	$4.9	$0.0	($0.0)	$0.0	$0.0	$4.9	758	12
Bedington	Transformer	AP	($0.5)	($4.4)	$0.0	$3.9	$0.0	$0.1	$0.0	($0.0)	$3.9	1,192	299
Altoona - Bear Rock	Line	PENELEC	($4.9)	($8.5)	($0.0)	$3.6	$0.1	$0.1	($0.0)	($0.0)	$3.6	221	30

Table 7-31 PENELEC Control Zone top congestion cost impacts (By facility): Calendar year 2007

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Bedington - Black Oak	Interface	500	($63.6)	($146.9)	$0.0	$83.4	($3.9)	$4.6	$0.4	($8.1)	$75.2	5,493	1,836
5004/5005 Interface	Interface	500	($11.5)	($59.0)	($1.0)	$46.6	($0.3)	$1.0	$0.4	($0.9)	$45.6	1,512	386
Wylie Ridge	Transformer	AP	$9.0	$28.8	$1.0	($18.9)	$1.9	($1.1)	($0.9)	$2.1	($16.9)	1,486	685
Kammer	Transformer	500	$11.4	$32.3	$1.5	($19.3)	$1.2	($1.8)	($0.5)	$2.5	($16.8)	2,005	947
Branchburg - Readington	Line	PSEG	($11.6)	($30.5)	($0.0)	$18.8	($3.6)	$1.5	$0.2	($4.8)	$14.0	2,324	721
Central	Interface	500	($2.3)	($15.2)	($0.1)	$12.8	($0.0)	$0.0	$0.0	($0.0)	$12.8	1,334	25
Bedington	Transformer	AP	($3.6)	($10.1)	$0.0	$6.5	$0.1	$0.0	$0.1	$0.3	$6.8	928	429
Elrama - Mitchell	Line	AP	$2.4	$8.6	$0.3	($5.9)	$0.5	($0.4)	($0.2)	$0.7	($5.1)	1,883	784
AP South	Interface	500	($4.1)	($8.8)	$0.3	$4.9	$0.3	$0.3	($0.1)	($0.1)	$4.9	706	133
Cloverdale - Lexington	Line	AEP	$0.5	$6.1	$1.7	($3.8)	$0.9	($0.4)	($1.6)	($0.3)	($4.0)	3,704	1,885
Seward	Transformer	PENELEC	$8.5	$5.0	$0.0	$3.5	$0.2	$0.1	$0.0	$0.1	$3.6	110	3
West	Interface	500	($1.8)	($7.7)	$0.0	$5.9	($0.7)	$1.7	$0.1	($2.3)	$3.6	359	338
East Towanda	Transformer	PENELEC	$8.1	($3.8)	$0.3	$12.1	($2.8)	$6.1	$0.1	($8.9)	$3.3	1,055	410
East	Interface	500	($1.7)	($4.5)	($0.0)	$2.8	($0.0)	$0.0	($0.0)	($0.0)	$2.8	304	5
Bear Rock - Johnstown	Line	PENELEC	($2.5)	($4.6)	($0.0)	$2.1	$0.0	$0.1	$0.0	($0.1)	$2.0	212	21

Pepco Control Zone

Table 7-32 and Table 7-33 show the constraints with the largest impacts on total congestion cost in the Pepco Control Zone for 2008 and 2007, respectively. In 2008, the AP South interface, Cloverdale – Lexington and Pruntytown – Mount Storm constraints were the top 3 contributors to positive congestion while the Central interface and Branchburg – Readington constraints contributed to negative congestion. In 2007, the Bedington – Black Oak and Cloverdale – Lexington constraints were the largest contributors to positive congestion while the Branchburg – Readington and Central interface constraints contributed to negative congestion.

Table 7-32 Pepco Control Zone top congestion cost impacts (By facility): Calendar year 2008

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
AP South	Interface	500	$186.4	$129.8	$1.8	$58.4	($2.6)	($1.4)	($1.8)	($2.9)	$55.5	3,572	997
Cloverdale - Lexington	Line	AEP	$91.0	$64.8	$1.8	$28.1	$5.9	($1.2)	($1.7)	$5.4	$33.5	3,529	1,739
Mount Storm - Pruntytown	Line	AP	$86.7	$61.8	$0.6	$25.5	$0.8	($1.5)	($0.3)	$2.0	$27.5	2,559	722
Bedington - Black Oak	Interface	500	$58.9	$40.0	$0.6	$19.5	($0.3)	$0.0	($0.3)	($0.7)	$18.8	1,384	279
Aqueduct - Doubs	Line	AP	$38.5	$23.5	$0.2	$15.2	$0.1	($0.0)	($0.0)	$0.1	$15.3	307	7
Kammer	Transformer	500	$36.9	$24.5	$0.7	$13.1	($0.3)	($0.9)	($0.7)	($0.0)	$13.1	3,069	1,567
Dickerson - Plesant View	Line	Pepco	$34.0	$23.1	$1.2	$12.1	($0.2)	($0.1)	($1.1)	($1.1)	$11.0	844	218
West	Interface	500	$25.0	$15.6	$0.6	$10.0	($0.3)	($0.5)	($0.6)	($0.4)	$9.6	1,690	385
Mount Storm	Transformer	AP	$25.8	$19.0	$0.1	$6.9	$2.0	($0.5)	($0.1)	$2.5	$9.3	935	373
Brighton	Transformer	Pepco	$11.7	$7.4	$0.2	$4.5	($0.7)	($0.3)	($0.8)	($1.2)	$3.3	116	78
Sammis - Wylie Ridge	Line	AP	$9.3	$6.3	$0.1	$3.1	$0.7	$0.2	($0.4)	$0.1	$3.2	1,915	1,239
Dickerson - Quince Orchard	Line	Pepco	$3.4	$1.1	$0.0	$2.4	($0.0)	($0.0)	$0.0	($0.0)	$2.4	46	2
Black Oak	Transformer	AP	$6.8	$4.6	$0.0	$2.2	($0.0)	($0.1)	($0.0)	$0.1	$2.3	386	29
Central	Interface	500	($8.1)	($6.0)	($0.1)	($2.1)	$0.0	($0.0)	($0.0)	$0.0	($2.1)	726	42
Branchburg - Readington	Line	PSEG	($5.4)	($3.6)	($0.2)	($2.0)	$0.3	$0.2	$0.2	$0.2	($1.8)	1,121	271

Table 7-33 Pepco Control Zone top congestion cost impacts (By facility): Calendar year 2007

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Bedington - Black Oak	Interface	500	$339.2	$265.1	$5.6	$79.7	$17.6	($10.4)	($5.1)	$22.9	$102.6	5,493	1,836
Cloverdale - Lexington	Line	AEP	$102.1	$80.2	$2.0	$23.9	$9.0	($7.1)	($2.3)	$13.8	$37.7	3,704	1,885
Kammer	Transformer	500	$35.5	$26.6	$0.7	$9.6	$1.5	($2.0)	($0.9)	$2.6	$12.3	2,005	947
AP South	Interface	500	$38.0	$28.8	$0.7	$9.9	$1.2	($0.4)	($0.2)	$1.4	$11.3	706	133
Branchburg - Readington	Line	PSEG	($36.9)	($31.4)	($0.2)	($5.8)	($2.8)	$3.0	$0.4	($5.3)	($11.1)	2,324	721
Wylie Ridge	Transformer	AP	$15.2	$12.1	$0.6	$3.7	$1.3	($1.0)	($0.6)	$1.6	$5.4	1,486	685
Bedington	Transformer	AP	$15.3	$11.3	$1.2	$5.3	$0.3	($0.6)	($1.0)	($0.1)	$5.1	928	429
Aqueduct - Doubs	Line	AP	$12.1	$8.0	$0.3	$4.3	($0.0)	($0.1)	($0.1)	($0.0)	$4.3	262	21
5004/5005 Interface	Interface	500	$8.8	$6.2	$0.3	$2.9	$0.1	($0.1)	($0.1)	$0.1	$3.0	1,512	386
Central	Interface	500	($14.8)	($12.0)	($0.1)	($2.9)	$0.0	$0.0	$0.0	($0.0)	($3.0)	1,334	25
Doubs	Transformer	AP	$9.0	$6.2	$0.2	$3.1	($0.2)	($0.2)	($0.6)	($0.7)	$2.4	135	99
Brunner Island - Yorkana	Line	Met-Ed	$4.8	$3.5	$0.3	$1.6	$0.7	($0.5)	($0.8)	$0.5	$2.1	172	196
Bedington - Nipetown	Line	AP	$5.3	$4.1	$0.1	$1.3	$0.4	($0.3)	($0.0)	$0.7	$1.9	841	175
Mount Storm - Pruntytown	Line	AP	$0.9	$0.7	$0.0	$0.2	$1.1	($0.7)	($0.3)	$1.5	$1.7	33	151
Elrama - Mitchell	Line	AP	$4.3	$3.2	$0.2	$1.3	$0.4	($0.3)	($0.4)	$0.4	$1.7	1,883	784

PPL Control Zone

Table 7-34 and Table 7-35 show the constraints with the largest impacts on total congestion cost in the PPL Control Zone for 2008 and 2007, respectively. In 2008, the Harwood – Susquehanna constraints was the largest contributor to positive congestion while the West interface and several other constraints contributed to negative congestion. In 2007, the Bedington – Black Oak and Brunner Island – Yorkana constraints were the largest contributors to positive congestion while the 5004/5005 Interface and Cloverdale – Lexington constraints contributed to negative congestion.

Table 7-34 PPL Control Zone top congestion cost impacts (By facility): Calendar year 2008

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Harwood - Susquehanna	Line	PPL	$2.7	($14.5)	($0.1)	$17.1	($1.2)	$2.0	$0.2	($3.0)	$14.1	117	99
West	Interface	500	$2.7	$13.2	$1.6	($8.9)	$0.2	$1.0	($0.2)	($1.0)	($9.9)	1,690	385
Cloverdale - Lexington	Line	AEP	$1.4	$9.0	$1.7	($5.8)	($0.2)	$0.0	($0.1)	($0.3)	($6.2)	3,529	1,739
East Towanda	Transformer	PENELEC	$0.4	$1.8	$0.0	($1.4)	$0.1	$1.1	($2.9)	($3.8)	($5.2)	803	306
East	Interface	500	$0.2	($4.6)	($0.0)	$4.8	$0.0	($0.0)	$0.0	$0.0	$4.8	758	12
Kammer	Transformer	500	$1.9	$7.4	$1.4	($4.1)	$0.2	$0.4	($0.3)	($0.5)	($4.7)	3,069	1,567
Sammis - Wylie Ridge	Line	AP	$0.3	$4.1	$0.6	($3.2)	$0.0	$0.1	($0.8)	($0.9)	($4.1)	1,915	1,239
Central	Interface	500	$0.8	$4.9	$0.4	($3.7)	($0.0)	($0.1)	($0.0)	$0.1	($3.6)	726	42
5004/5005 Interface	Interface	500	$1.5	$5.6	$0.8	($3.3)	($0.2)	($0.2)	($0.3)	($0.3)	($3.6)	736	411
Mount Storm - Pruntytown	Line	AP	$1.8	($0.8)	$1.0	$3.5	$0.1	$0.2	($0.1)	($0.1)	$3.4	2,559	722
Krendale - Seneca	Line	AP	$0.4	$2.4	$0.3	($1.7)	($0.0)	$0.0	$0.0	($0.0)	($1.7)	1,389	24
Bedington - Black Oak	Interface	500	$1.6	$0.6	$0.5	$1.5	$0.1	$0.0	$0.1	$0.1	$1.6	1,384	279
Branchburg - Readington	Line	PSEG	$0.7	($0.8)	($0.1)	$1.4	$0.0	($0.1)	$0.1	$0.2	$1.6	1,121	271
Conastone	Transformer	BGE	$0.1	($1.2)	($0.0)	$1.2	$0.0	($0.0)	$0.0	$0.1	$1.3	95	15
Burnham - Munster	Line	ComEd	$0.3	$1.5	($0.0)	($1.3)	$0.0	($0.1)	$0.0	$0.2	($1.1)	476	140

Table 7-35 PPL Control Zone top congestion cost impacts (By facility): Calendar year 2007

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
5004/5005 Interface	Interface	500	$3.1	$13.9	$1.2	($9.6)	$0.3	$0.8	($0.2)	($0.7)	($10.3)	1,512	386
Bedington - Black Oak	Interface	500	$10.9	$7.6	$2.2	$5.6	$1.6	$2.1	$1.1	$0.6	$6.3	5,493	1,836
Cloverdale - Lexington	Line	AEP	$1.6	$9.5	$1.5	($6.5)	$1.0	$1.0	$0.5	$0.5	($6.0)	3,704	1,885
Central	Interface	500	$1.2	$6.3	$0.5	($4.6)	$0.0	($0.0)	$0.0	$0.0	($4.6)	1,334	25
Brunner Island - Yorkana	Line	Met-Ed	($0.2)	($5.1)	($0.1)	$4.7	($0.4)	$0.8	($0.0)	($1.3)	$3.5	172	196
Branchburg - Readington	Line	PSEG	($1.1)	($6.2)	($0.2)	$4.9	($0.6)	($0.2)	($1.2)	($1.6)	$3.2	2,324	721
Kammer	Transformer	500	$1.8	$6.0	$0.8	($3.4)	$0.9	$1.1	$0.4	$0.3	($3.1)	2,005	947
Manor - Safe Harbor	Line	Met-Ed	$2.1	($0.7)	$0.0	$2.8	$0.0	$0.0	$0.0	$0.0	$2.8	95	0
Conastone	Transformer	BGE	$0.2	($2.5)	($0.0)	$2.7	$0.1	$0.1	($0.0)	($0.0)	$2.7	172	55
Wylie Ridge	Transformer	AP	$1.1	$4.9	$0.6	($3.2)	$0.8	$0.2	($0.0)	$0.5	($2.7)	1,486	685
East	Interface	500	($0.1)	($2.2)	($0.0)	$2.1	$0.0	$0.0	($0.0)	($0.0)	$2.1	304	5
Cedar Grove - Roseland	Line	PSEG	($0.4)	($2.2)	($0.1)	$1.7	($0.1)	($0.0)	$0.0	($0.1)	$1.6	1,677	133
West	Interface	500	$0.6	$1.7	$0.2	($0.9)	$0.4	$1.2	$0.2	($0.6)	($1.5)	359	338
Elrama - Mitchell	Line	AP	$0.3	$1.5	$0.2	($1.1)	$0.1	$0.3	$0.0	($0.2)	($1.3)	1,883	784
Middletown Jct - Brunner Island	Line	PPL	($0.0)	($0.1)	($0.0)	$0.1	$0.0	($1.1)	$0.0	$1.1	$1.2	4	9

PSEG Control Zone

Table 7-36 and Table 7-37 show the constraints with the largest impacts on total congestion cost in the PSEG Control Zone for 2008 and 2007, respectively. In 2008, the Atlantic – Larrabee and Branchburg – Readington constraints were the largest contributors to positive congestion while the AP South interface and Mount Storm – Pruntytown constraints were the largest contributors to negative congestion costs. In 2007, the Branchburg – Readington and Cedar Grove – Roseland constraints were the largest contributors to positive congestion while the Bedington – Black Oak and South Mahwah – Waldwick constraints contributed to negative congestion.

Table 7-36 PSEG Control Zone top congestion cost impacts (By facility): Calendar year 2008

			Congestion Costs (Millions)									Event Hours	
			Day Ahead				Balancing						
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Atlantic - Larrabee	Line	JCPL	$13.3	($6.0)	$0.4	$19.7	$0.5	$2.7	($0.9)	($3.1)	$16.6	1,556	380
Branchburg - Readington	Line	PSEG	$17.0	$0.8	$0.8	$17.0	$0.2	$2.9	($0.7)	($3.3)	$13.6	1,121	271
Buckingham - Pleasant Valley	Line	PECO	$11.4	$2.4	$0.6	$9.6	($0.1)	$0.4	($0.1)	($0.6)	$9.0	647	74
Cedar Grove - Roseland	Line	PSEG	$12.6	$1.9	$0.5	$11.3	($0.0)	$2.7	($0.9)	($3.6)	$7.7	627	168
Branchburg - Flagtown	Line	PSEG	$6.9	$0.1	$0.2	$6.9	$0.4	($0.0)	($0.4)	($0.0)	$6.9	284	61
Unclassified	Unclassified	Unclassified	$3.7	($2.9)	$0.2	$6.8	($0.0)	$0.0	$0.0	($0.0)	$6.8	NA	NA
AP South	Interface	500	$25.3	$31.6	$3.9	($2.4)	($0.1)	$1.0	($2.2)	($3.3)	($5.7)	3,572	997
Brunswick - Edison	Line	PSEG	$5.6	$0.3	$0.3	$5.6	($0.0)	$0.6	($0.3)	($0.9)	$4.6	535	264
Mount Storm - Pruntytown	Line	AP	$1.7	$6.6	$1.9	($2.9)	$0.1	($0.2)	($1.5)	($1.2)	($4.1)	2,559	722
Trainer - Delco Tap	Line	PECO	($2.2)	($5.9)	($0.1)	$3.6	$0.0	$0.0	$0.0	$0.0	$3.6	2,218	0
Cloverdale - Lexington	Line	AEP	$22.1	$24.9	$2.8	($0.0)	$0.4	$1.9	($2.0)	($3.5)	($3.5)	3,529	1,739
Sammis - Wylie Ridge	Line	AP	$7.5	$8.1	$1.0	$0.4	$0.8	$1.9	($2.7)	($3.7)	($3.3)	1,915	1,239
Bedington - Black Oak	Interface	500	$3.8	$7.3	$1.0	($2.4)	$0.0	($0.0)	($0.4)	($0.4)	($2.8)	1,384	279
Leonia - New Milford	Line	PSEG	$1.7	$0.4	$2.5	$3.8	($0.2)	$0.7	($0.5)	($1.3)	$2.5	919	84
Athenia - Fairlawn	Line	PSEG	$2.0	$0.3	$0.7	$2.4	($0.0)	$0.0	($0.3)	($0.3)	$2.1	428	36

Table 7-37 PSEG Control Zone top congestion cost impacts (By facility): Calendar year 2007

			Congestion Costs (Millions)									Event Hours	
			Day Ahead				Balancing						
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Branchburg - Readington	Line	PSEG	$37.7	($13.1)	$0.3	$51.2	$2.8	$11.7	($2.5)	($11.4)	$39.8	2,324	721
Cedar Grove - Roseland	Line	PSEG	$13.9	$0.0	($0.3)	$13.6	$0.3	$0.5	($0.1)	($0.4)	$13.2	1,677	133
Branchburg - Flagtown	Line	PSEG	$10.2	$0.3	$0.3	$10.2	($0.0)	($0.3)	($0.7)	($0.5)	$9.7	580	104
Bedington - Black Oak	Interface	500	$40.8	$49.1	$5.0	($3.3)	$0.0	$2.1	($3.2)	($5.3)	($8.6)	5,493	1,836
Atlantic - Larrabee	Line	JCPL	$6.6	($2.8)	$0.2	$9.6	$0.3	$1.0	($0.6)	($1.4)	$8.2	680	134
South Mahwah - Waldwick	Line	PSEG	$2.7	$1.1	($0.9)	$0.7	($1.6)	$1.5	($4.9)	($8.0)	($7.3)	304	58
5004/5005 Interface	Interface	500	$33.4	$29.6	$2.0	$5.7	$1.1	$0.7	($0.7)	($0.3)	$5.4	1,512	386
Brunswick - Edison	Line	PSEG	$4.6	$0.4	$0.2	$4.4	$0.2	$0.1	($0.1)	($0.0)	$4.4	667	125
Edison - Meadow Rd	Line	PSEG	$3.8	$0.4	$0.3	$3.7	$0.1	$0.1	($0.2)	($0.2)	$3.5	438	143
Wylie Ridge	Transformer	AP	$14.7	$12.1	$1.0	$3.6	$0.6	$1.3	($0.9)	($1.7)	$1.9	1,486	685
Linden - North Ave	Line	PSEG	$1.1	($0.5)	$0.1	$1.7	$0.0	($0.0)	($0.0)	$0.0	$1.7	421	1
Cloverdale - Lexington	Line	AEP	$28.1	$27.6	$2.3	$2.7	$0.5	$2.9	($1.9)	($4.3)	($1.6)	3,704	1,885
Central	Interface	500	$18.9	$18.2	$0.9	$1.6	$0.0	$0.0	($0.0)	$0.0	$1.6	1,334	25
Bergen - Hoboken	Line	PSEG	$0.4	($0.3)	$0.7	$1.5	($0.0)	($0.0)	($0.0)	$0.0	$1.5	210	9
Athenia - Saddlebrook	Line	PSEG	$0.9	$0.6	$0.9	$1.2	($0.1)	($0.1)	$0.0	$0.0	$1.2	173	15

RECO Control Zone

Table 7-38 and Table 7-39 show the constraints with the largest impacts on total congestion cost in the RECO Control Zone for 2008 and 2007, respectively. In 2008, the West interface and Branchburg – Readington constraints were the largest contributors to positive congestion. No constraints were significant contributors to negative congestion during 2008. In 2007, the Branchburg – Readington and 5004/5005 interface constraints were the largest contributors to positive congestion while the South Mahwah – Waldwick and Brunner Island – Yorkana constraints contributed to negative congestion.

Table 7-38 RECO Control Zone top congestion cost impacts (By facility): Calendar year 2008

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
West	Interface	500	$1.4	$0.0	$0.2	$1.6	$0.1	($0.0)	($0.4)	($0.3)	$1.3	1,690	385
Branchburg - Readington	Line	PSEG	$1.0	$0.0	$0.0	$1.0	$0.0	($0.0)	($0.0)	$0.0	$1.0	1,121	271
Cedar Grove - Roseland	Line	PSEG	$0.8	$0.0	$0.0	$0.8	$0.1	($0.0)	($0.0)	$0.1	$0.9	627	168
Kammer	Transformer	500	$0.8	$0.0	$0.1	$0.9	$0.0	($0.0)	($0.1)	($0.0)	$0.9	3,069	1,567
Cloverdale - Lexington	Line	AEP	$0.7	$0.0	$0.2	$0.8	$0.0	($0.0)	($0.1)	($0.1)	$0.8	3,529	1,739
AP South	Interface	500	$0.7	$0.0	$0.1	$0.7	$0.0	($0.0)	($0.1)	($0.1)	$0.6	3,572	997
Atlantic - Larrabee	Line	JCPL	$0.6	$0.0	$0.0	$0.6	$0.0	($0.0)	($0.1)	($0.0)	$0.5	1,556	380
Central	Interface	500	$0.5	$0.0	$0.0	$0.5	($0.0)	($0.0)	($0.0)	($0.0)	$0.5	726	42
East	Interface	500	$0.5	$0.0	$0.0	$0.5	($0.0)	($0.0)	($0.0)	($0.0)	$0.5	758	12
Buckingham - Pleasant Valley	Line	PECO	$0.5	$0.0	$0.0	$0.5	$0.0	($0.0)	($0.0)	$0.0	$0.5	647	74
5004/5005 Interface	Interface	500	$0.5	$0.0	$0.1	$0.6	$0.0	($0.0)	($0.3)	($0.3)	$0.3	736	411
Krendale - Seneca	Line	AP	$0.2	$0.0	$0.1	$0.3	($0.0)	($0.0)	$0.0	$0.0	$0.3	1,389	24
Dickerson - Plesant View	Line	Pepco	$0.3	$0.0	$0.0	$0.3	($0.0)	($0.0)	($0.0)	($0.0)	$0.3	844	218
Cedar Grove - Clifton	Line	PSEG	$0.2	$0.0	$0.0	$0.2	$0.1	($0.0)	($0.0)	$0.1	$0.3	793	372
Burnham - Munster	Line	ComEd	$0.2	$0.0	$0.0	$0.2	$0.0	($0.0)	$0.0	$0.0	$0.2	476	140

Table 7-39 RECO Control Zone top congestion cost impacts (By facility): Calendar year 2007

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Branchburg - Readington	Line	PSEG	$2.9	$0.1	$0.2	$3.1	($0.1)	($0.2)	($0.3)	($0.2)	$2.9	2,324	721
5004/5005 Interface	Interface	500	$1.3	$0.0	$0.0	$1.2	$0.1	($0.0)	($0.0)	$0.1	$1.3	1,512	386
Cedar Grove - Roseland	Line	PSEG	$1.1	$0.0	$0.0	$1.0	$0.0	($0.0)	($0.0)	$0.1	$1.1	1,677	133
Cloverdale - Lexington	Line	AEP	$0.8	$0.0	$0.0	$0.8	$0.1	($0.0)	($0.0)	$0.1	$0.9	3,704	1,885
Bedington - Black Oak	Interface	500	$1.0	$0.0	$0.0	$0.9	($0.0)	($0.0)	($0.1)	($0.1)	$0.9	5,493	1,836
South Mahwah - Waldwick	Line	PSEG	($0.1)	($0.0)	($0.0)	($0.2)	($0.1)	$0.6	$0.0	($0.7)	($0.8)	304	58
Kammer	Transformer	500	$0.7	$0.0	$0.0	$0.7	$0.1	($0.0)	($0.0)	$0.1	$0.8	2,005	947
Central	Interface	500	$0.7	$0.0	$0.0	$0.7	$0.0	($0.0)	$0.0	$0.0	$0.7	1,334	25
Wylie Ridge	Transformer	AP	$0.6	$0.0	$0.0	$0.6	$0.0	($0.0)	($0.0)	$0.0	$0.6	1,486	685
Atlantic - Larrabee	Line	JCPL	$0.3	$0.0	$0.0	$0.3	$0.0	($0.0)	$0.0	$0.0	$0.3	680	134
West	Interface	500	$0.2	$0.0	$0.0	$0.2	$0.0	($0.0)	($0.0)	$0.0	$0.3	359	338
AP South	Interface	500	$0.2	$0.1	$0.0	$0.2	$0.0	($0.0)	($0.0)	$0.0	$0.2	706	133
East	Interface	500	$0.2	$0.0	$0.0	$0.2	$0.0	($0.0)	$0.0	$0.0	$0.2	304	5
Brunner Island - Yorkana	Line	Met-Ed	($0.2)	($0.0)	$0.0	($0.2)	($0.0)	$0.0	$0.0	($0.0)	($0.2)	172	196
Branchburg - Flagtown	Line	PSEG	$0.2	$0.0	$0.0	$0.2	$0.0	($0.0)	($0.0)	$0.0	$0.2	580	104

Western Region Congestion-Event Summaries

AEP Control Zone

Table 7-40 and Table 7-41 show the constraints with the largest impacts on total congestion cost in the AEP Control Zone for 2008 and 2007, respectively. In 2008, the AP South, Mount Storm – Pruntytown, Kammer, and Bedington – Black Oak constraints were the largest contributors to positive congestion while the Sammis – Wylie Ridge and Cloverdale – Lexington constraints contributed to negative congestion. In 2007, the Bedington – Black Oak and Kammer transformer constraints were the largest contributors to positive congestion while the Cloverdale – Lexington and Darwin – Eugene constraints contributed to negative congestion.

Table 7-40 AEP Control Zone top congestion cost impacts (By facility): Calendar year 2008

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
AP South	Interface	500	($88.3)	($149.7)	$2.4	$63.8	($15.1)	$0.6	$0.3	($15.4)	$48.4	3,572	997
Mount Storm - Pruntytown	Line	AP	($28.8)	($71.8)	$3.8	$46.9	($9.2)	$0.4	($0.4)	($9.9)	$36.9	2,559	722
Kammer	Transformer	500	($31.2)	($80.1)	($0.5)	$48.3	($10.1)	$3.9	$0.4	($13.5)	$34.8	3,069	1,567
Bedington - Black Oak	Interface	500	($21.7)	($47.4)	$2.1	$27.8	($2.5)	$0.9	$0.0	($3.4)	$24.4	1,384	279
Axton	Transformer	AEP	$2.8	($13.0)	$2.2	$18.1	$0.0	$0.0	$0.0	$0.0	$18.1	425	0
West	Interface	500	($23.8)	($41.1)	$0.2	$17.5	($3.3)	$0.9	$0.1	($4.1)	$13.4	1,690	385
Sammis - Wylie Ridge	Line	AP	($17.1)	($9.7)	($0.3)	($7.7)	($4.3)	($0.5)	($1.4)	($5.2)	($12.9)	1,915	1,239
Mount Storm	Transformer	AP	($8.9)	($23.7)	$1.4	$16.2	($5.2)	($1.6)	($0.2)	($3.8)	$12.5	935	373
Cloverdale - Lexington	Line	AEP	($96.5)	($104.8)	($6.0)	$2.3	($16.0)	($3.7)	$0.9	($11.4)	($9.1)	3,529	1,739
Amos	Transformer	AEP	$5.9	($1.6)	$0.2	$7.7	$0.4	$0.6	$0.1	($0.2)	$7.5	31	19
Mahans Lane - Tidd	Line	AEP	($2.0)	($4.8)	$2.8	$5.6	$0.1	$0.2	$0.0	($0.0)	$5.6	847	211
Bedington	Transformer	AP	($4.7)	($8.9)	$0.3	$4.5	($0.5)	$0.1	($0.0)	($0.6)	$3.9	1,192	299
Breed - Wheatland	Line	AEP	$0.1	($3.9)	($0.4)	$3.5	$0.0	($0.0)	$0.0	$0.0	$3.5	338	1
Central	Interface	500	($6.3)	($9.8)	($0.0)	$3.4	($0.0)	$0.1	$0.0	($0.1)	$3.3	726	42
Aqueduct - Doubs	Line	AP	($5.6)	($8.7)	$0.1	$3.3	($0.1)	($0.0)	$0.0	($0.1)	$3.2	307	7

Table 7-41 AEP Control Zone top congestion cost impacts (By facility): Calendar year 2007

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Bedington - Black Oak	Interface	500	($69.4)	($183.1)	$7.3	$120.9	($24.1)	$10.7	($0.3)	($35.2)	$85.7	5,493	1,836
Kammer	Transformer	500	($32.1)	($68.3)	($0.2)	$36.0	($9.8)	$2.8	$0.0	($12.6)	$23.4	2,005	947
Amos	Transformer	AEP	$14.3	($3.3)	$0.3	$17.8	$3.0	$2.6	($0.2)	$0.2	$18.0	311	132
5004/5005 Interface	Interface	500	($24.6)	($41.3)	$0.5	$17.3	($2.9)	$0.1	($0.1)	($3.1)	$14.2	1,512	386
Cloverdale - Lexington	Line	AEP	($87.9)	($91.3)	($5.3)	($2.0)	($16.5)	($5.1)	$0.2	($11.2)	($13.1)	3,704	1,885
Axton	Transformer	AEP	$1.8	($5.5)	$1.0	$8.3	$0.0	$0.0	$0.0	$0.0	$8.3	238	0
AP South	Interface	500	($15.2)	($26.0)	$0.3	$11.0	($3.3)	$0.8	$0.0	($4.1)	$6.9	706	133
Wylie Ridge	Transformer	AP	($13.4)	($27.4)	$1.3	$15.3	($6.7)	$2.4	($0.2)	($9.2)	$6.1	1,486	685
Central	Interface	500	($13.2)	($19.0)	$0.0	$5.8	($0.1)	($0.0)	$0.0	($0.0)	$5.8	1,334	25
Bedington	Transformer	AP	($6.3)	($13.5)	$0.4	$7.6	($1.7)	$0.4	($0.0)	($2.1)	$5.5	928	429
Kanawha - Matt Funk	Line	AEP	$0.6	($6.0)	$0.9	$7.5	($1.5)	$1.2	($0.2)	($2.8)	$4.7	90	95
Axton - Jacksons Ferry	Line	AEP	$1.0	($3.2)	$0.6	$4.8	($0.0)	$0.1	($0.0)	($0.2)	$4.6	238	5
Kanawha River	Transformer	AEP	$2.1	($0.7)	$0.6	$3.5	$0.1	$0.1	$0.0	($0.0)	$3.5	63	12
Darwin - Eugene	Line	AEP	($0.0)	($3.0)	($0.1)	$2.9	$0.6	$6.6	($0.1)	($6.1)	($3.3)	109	227
Cloverdale	Transformer	AEP	($1.6)	($5.6)	$0.2	$4.2	($1.5)	$0.6	($0.0)	($2.1)	$2.2	233	152

AP Control Zone

Table 7-42 and Table 7-43 show the constraints with the largest impacts on total congestion cost in the AP Control Zone for 2008 and 2007, respectively. In 2008, the AP South interface was the largest contributor to positive congestion while the Sammis – Wylie Ridge line, Aqueduct – Doubs line, and the Kammer transformer constraints contributed to negative congestion. In 2007, the Bedington – Black Oak and Cloverdale – Lexington constraints were the largest contributors to positive congestion while the Kammer and Wylie Ridge transformer constraints contributed to negative congestion.

Table 7-42 AP Control Zone top congestion cost impacts (By facility): Calendar year 2008

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
AP South	Interface	500	$9.2	($141.1)	($0.3)	$150.0	$2.8	$8.7	$1.2	($4.6)	$145.3	3,572	997
Mount Storm - Pruntytown	Line	AP	($8.2)	($94.1)	($0.4)	$85.5	($0.3)	$3.7	($0.1)	($4.1)	$81.4	2,559	722
Bedington - Black Oak	Interface	500	($3.8)	($57.5)	($1.3)	$52.5	$0.7	$0.3	$0.8	$1.2	$53.7	1,384	279
Cloverdale - Lexington	Line	AEP	$21.4	($27.6)	$6.2	$55.2	($3.1)	($0.5)	($7.8)	($10.5)	$44.8	3,529	1,739
Bedington	Transformer	AP	$32.9	($7.7)	$1.3	$41.9	($0.6)	($0.6)	($0.5)	($0.6)	$41.4	1,192	299
Meadow Brook	Transformer	AP	$28.4	($1.5)	$0.6	$30.5	($3.1)	($0.2)	($0.1)	($3.1)	$27.4	774	173
Mount Storm	Transformer	AP	$0.8	($28.2)	$1.1	$30.2	($2.0)	$2.3	($0.9)	($5.2)	$25.0	935	373
Sammis - Wylie Ridge	Line	AP	$11.5	$7.8	$5.7	$9.4	($7.1)	$1.0	($15.0)	($23.1)	($13.7)	1,915	1,239
Kammer	Transformer	500	$26.7	$39.9	$7.1	($6.2)	($3.5)	($2.7)	($6.4)	($7.1)	($13.3)	3,069	1,567
Aqueduct - Doubs	Line	AP	($17.0)	($6.0)	($0.4)	($11.3)	$0.1	$0.1	$0.0	$0.0	($11.3)	307	7
Krendale - Seneca	Line	AP	$7.8	($0.1)	$2.2	$10.1	($0.0)	$0.0	($0.0)	($0.1)	$10.0	1,389	24
West	Interface	500	($18.7)	($25.4)	($0.7)	$6.0	$2.0	$1.0	$0.7	$1.7	$7.7	1,690	385
Cedar Grove - Roseland	Line	PSEG	$5.7	$1.8	$2.0	$5.9	$0.0	$0.0	$0.4	$0.4	$6.3	627	168
5004/5005 Interface	Interface	500	($6.9)	($12.0)	($0.4)	$4.8	$1.7	$1.3	$0.8	$1.2	$6.0	736	411
Kingwood - Pruntytown	Line	AP	$5.2	($0.0)	$0.1	$5.3	$0.0	$0.0	($0.0)	$0.0	$5.3	360	13

Table 7-43 AP Control Zone top congestion cost impacts (By facility): Calendar year 2007

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Bedington - Black Oak	Interface	500	($18.0)	($275.2)	$4.3	$261.5	($9.3)	$15.3	$3.4	($21.3)	$240.2	5,493	1,836
Cloverdale - Lexington	Line	AEP	$27.5	($19.8)	$7.0	$54.3	($1.6)	$1.6	($4.4)	($7.6)	$46.7	3,704	1,885
Meadow Brook	Transformer	AP	$32.6	$0.2	$0.6	$33.0	($0.4)	($0.6)	($0.2)	($0.1)	$32.9	868	233
Bedington	Transformer	AP	$20.6	($13.6)	($0.1)	$34.1	($3.0)	($0.4)	($0.5)	($3.1)	$31.0	928	429
AP South	Interface	500	$3.0	($21.7)	$0.6	$25.3	($0.6)	$1.2	$0.2	($1.6)	$23.7	706	133
Branchburg - Readington	Line	PSEG	($20.6)	($24.4)	$8.9	$12.6	$0.7	$1.9	$0.6	($0.6)	$12.0	2,324	721
5004/5005 Interface	Interface	500	($22.6)	($32.2)	$0.2	$9.7	$0.1	$0.4	$0.2	($0.1)	$9.6	1,512	386
Kammer	Transformer	500	$28.3	$40.7	$4.4	($8.0)	($0.6)	($2.9)	($3.8)	($1.5)	($9.5)	2,005	947
Elrama - Mitchell	Line	AP	$10.9	$3.2	$3.4	$11.0	($0.9)	$0.5	($2.2)	($3.6)	$7.4	1,883	784
Bedington - Nipetown	Line	AP	$5.0	($2.7)	$0.2	$7.9	($0.3)	$0.8	$0.1	($1.1)	$6.9	841	175
Wylie Ridge	Transformer	AP	$10.0	$13.4	$3.0	($0.4)	($1.5)	$0.4	($3.6)	($5.5)	($5.9)	1,486	685
Doubs	Transformer	AP	$4.1	($1.5)	$0.1	$5.7	$0.1	($0.0)	($0.2)	($0.0)	$5.7	135	99
Cedar Grove - Roseland	Line	PSEG	$1.8	($2.2)	$1.3	$5.3	$0.0	$0.0	$0.1	$0.1	$5.4	1,677	133
Central	Interface	500	($11.5)	($14.4)	$1.3	$4.1	($0.0)	$0.0	$0.0	($0.0)	$4.1	1,334	25
Aqueduct - Doubs	Line	AP	($6.1)	($3.1)	($0.3)	($3.4)	$0.1	$0.0	$0.0	$0.1	($3.2)	262	21

ComEd Control Zone

Table 7-44 and Table 7-45 show the constraints with the largest impacts on total congestion cost in the ComEd Control Zone for 2008 and 2007, respectively. In 2008, the Cloverdale – Lexington line and the AP South interface constraints were the largest contributors to positive congestion. The Crete – East Frankfort line contributed to negative congestion in 2008. In 2007, the Bedington – Black Oak and Cloverdale – Lexington constraints were the largest contributors to positive congestion while the South Mahwah – Waldwick constraint contributed to negative congestion.

Table 7-44 ComEd Control Zone top congestion cost impacts (By facility): Calendar year 2008

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Cloverdale - Lexington	Line	AEP	($68.5)	($129.4)	$0.6	$61.5	($5.5)	($1.3)	($0.2)	($4.4)	$57.2	3,529	1,739
AP South	Interface	500	($94.4)	($145.2)	$1.1	$51.9	($5.2)	($1.2)	($0.1)	($4.2)	$47.7	3,572	997
Kammer	Transformer	500	($41.3)	($72.2)	($0.0)	$30.8	($5.1)	$2.9	($0.1)	($8.1)	$22.7	3,069	1,567
East Frankfort - Crete	Line	ComEd	($14.4)	($32.9)	($0.1)	$18.4	$0.0	$0.0	$0.0	$0.0	$18.4	1,002	0
Mount Storm - Pruntytown	Line	AP	($45.5)	($70.9)	$0.0	$25.5	($6.5)	$1.1	($0.2)	($7.9)	$17.6	2,559	722
Bedington - Black Oak	Interface	500	($25.4)	($42.0)	$0.2	$16.8	($0.2)	($0.4)	$0.0	$0.2	$17.0	1,384	279
West	Interface	500	($26.9)	($42.8)	$0.1	$16.0	($0.3)	($0.7)	($0.0)	$0.4	$16.4	1,690	385
Burnham - Munster	Line	ComEd	($23.6)	($38.2)	$2.2	$16.8	($2.6)	($2.6)	($0.5)	($0.5)	$16.3	476	140
Dunes Acres - Michigan City	Flowgate	Midwest ISO	($9.5)	($17.3)	$0.0	$7.8	($2.1)	$0.1	($0.2)	($2.4)	$5.4	687	435
Krendale - Seneca	Line	AP	($6.1)	($11.0)	($0.0)	$4.8	$0.0	($0.0)	$0.0	$0.0	$4.9	1,389	24
Crete - East Frankfort	Line	ComEd	$0.0	$0.0	$0.0	$0.0	($5.0)	($1.1)	($0.7)	($4.6)	($4.6)	0	334
Central	Interface	500	($5.6)	($10.0)	($0.0)	$4.4	($0.1)	($0.1)	($0.0)	($0.1)	$4.3	726	42
Axton	Transformer	AEP	($7.2)	($11.4)	$0.1	$4.3	$0.0	$0.0	$0.0	$0.0	$4.3	425	0
Dickerson - Plesant View	Line	Pepco	($6.4)	($10.2)	$0.0	$3.8	($0.2)	($0.4)	$0.0	$0.2	$4.0	844	218
5004/5005 Interface	Interface	500	($10.3)	($15.6)	($0.0)	$5.3	($1.4)	($0.0)	($0.0)	($1.4)	$3.9	736	411

Table 7-45 ComEd Control Zone top congestion cost impacts (By facility): Calendar year 2007

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Bedington - Black Oak	Interface	500	($99.4)	($126.5)	($0.6)	$26.5	$10.8	($8.0)	$0.2	$19.1	$45.5	5,493	1,836
Cloverdale - Lexington	Line	AEP	($53.5)	($80.0)	($0.1)	$26.4	$8.5	($8.8)	($0.1)	$17.2	$43.6	3,704	1,885
Kammer	Transformer	500	($32.9)	($44.5)	($0.1)	$11.5	$6.6	($4.1)	($0.0)	$10.7	$22.2	2,005	947
Branchburg - Readington	Line	PSEG	($19.0)	($19.5)	$0.0	$0.5	$6.2	($3.2)	$0.0	$9.5	$10.0	2,324	721
Wylie Ridge	Transformer	AP	($14.6)	($17.3)	($0.0)	$2.8	$3.0	($3.4)	$0.0	$6.5	$9.2	1,486	685
5004/5005 Interface	Interface	500	($23.3)	($28.6)	($0.0)	$5.2	$1.3	($0.9)	$0.0	$2.2	$7.5	1,512	386
AP South	Interface	500	($14.7)	($17.3)	($0.0)	$2.5	$0.8	($1.0)	$0.0	$1.9	$4.4	706	133
Central	Interface	500	($10.5)	($13.4)	$0.0	$3.0	$0.0	($0.0)	($0.0)	$0.0	$3.0	1,334	25
West	Interface	500	($4.2)	($4.3)	($0.0)	$0.1	$1.5	($0.8)	$0.0	$2.3	$2.5	359	338
Kanawha - Matt Funk	Line	AEP	($4.5)	($6.3)	($0.0)	$1.8	$0.3	($0.3)	$0.0	$0.6	$2.3	90	95
Cloverdale	Transformer	AEP	($3.0)	($4.8)	($0.0)	$1.7	$0.3	($0.2)	$0.0	$0.5	$2.2	233	152
Elrama - Mitchell	Line	AP	($4.0)	($5.5)	($0.0)	$1.6	$0.2	($0.3)	$0.0	$0.5	$2.1	1,883	784
State Line - Wolf Lake	Flowgate	Midwest ISO	($4.9)	($7.7)	($0.1)	$2.7	$0.5	$1.1	$0.0	($0.6)	$2.1	1,241	590
Dresden	Transformer	ComEd	$1.7	($0.6)	$0.0	$2.3	($0.1)	$0.3	($0.0)	($0.5)	$1.8	77	22
South Mahwah - Waldwick	Line	PSEG	$1.4	$1.5	$0.0	($0.1)	($0.7)	$0.8	($0.0)	($1.5)	($1.6)	304	58

DAY Control Zone

Table 7-46 and Table 7-47 show the constraints with the largest impacts on total congestion cost in the DAY Control Zone for 2008 and 2007, respectively. In 2008, the Cloverdale – Lexington line was the largest contributor to positive congestion while the Mount Storm – Pruntytown line contributed to negative congestion. In 2007, the Cloverdale – Lexington and Kammer transformer constraints were the largest contributors to positive congestion while the Amos transformer constraint contributed to negative congestion.

Table 7-46 DAY Control Zone top congestion cost impacts (By facility): Calendar year 2008

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Cloverdale - Lexington	Line	AEP	($8.4)	($10.9)	$0.1	$2.5	$0.3	($0.6)	$0.0	$1.0	$3.5	3,529	1,739
Kammer	Transformer	500	($5.0)	($6.4)	($0.0)	$1.3	$1.1	$0.3	$0.0	$0.9	$2.2	3,069	1,567
AP South	Interface	500	($9.5)	($12.0)	($0.0)	$2.5	$0.4	$0.8	($0.0)	($0.4)	$2.1	3,572	997
Bedington - Black Oak	Interface	500	($2.9)	($4.2)	($0.0)	$1.3	$0.1	$0.3	($0.0)	($0.3)	$1.0	1,384	279
West	Interface	500	($2.5)	($3.9)	$0.0	$1.4	$0.2	$0.6	($0.0)	($0.5)	$0.9	1,690	385
Mount Storm - Pruntytown	Line	AP	($5.2)	($4.7)	$0.0	($0.5)	$0.1	$0.4	($0.0)	($0.3)	($0.8)	2,559	722
5004/5005 Interface	Interface	500	($0.9)	($1.6)	$0.0	$0.7	$0.1	$0.1	($0.0)	($0.0)	$0.7	736	411
Axton	Transformer	AEP	($0.7)	($1.1)	($0.0)	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	425	0
Central	Interface	500	($0.6)	($1.0)	$0.0	$0.4	$0.0	$0.0	$0.0	($0.0)	$0.4	726	42
Conemaugh - Keystone	Line	500	($0.0)	($0.0)	$0.0	$0.0	$0.3	$0.0	($0.0)	$0.3	$0.3	16	41
Dickerson - Plesant View	Line	Pepco	($0.6)	($0.9)	$0.0	$0.3	($0.0)	$0.0	$0.0	($0.0)	$0.3	844	218
Sammis - Wylie Ridge	Line	AP	($1.5)	($1.2)	($0.0)	($0.4)	$0.8	($0.0)	($0.2)	$0.6	$0.2	1,915	1,239
Mount Storm	Transformer	AP	($1.8)	($1.3)	$0.0	($0.4)	($0.0)	($0.2)	($0.0)	$0.1	($0.2)	935	373
Axton - Jacksons Ferry	Line	AEP	($0.1)	($0.3)	($0.0)	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	83	0
Whitpain	Transformer	PECO	($0.0)	($0.1)	$0.0	$0.1	$0.0	($0.0)	($0.0)	$0.1	$0.2	89	68

Table 7-47 DAY Control Zone top congestion cost impacts (By facility): Calendar year 2007

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Cloverdale - Lexington	Line	AEP	($5.0)	($10.9)	$0.1	$6.0	($0.6)	($0.5)	($0.0)	($0.1)	$6.0	3,704	1,885
Kammer	Transformer	500	($3.3)	($6.1)	($0.0)	$2.8	($0.2)	$0.9	($0.0)	($1.1)	$1.7	2,005	947
Bedington - Black Oak	Interface	500	($11.7)	($15.2)	($0.1)	$3.3	($1.5)	$0.8	($0.0)	($2.3)	$1.0	5,493	1,836
Central	Interface	500	($1.0)	($1.9)	$0.0	$0.9	($0.0)	$0.0	$0.0	($0.0)	$0.9	1,334	25
5004/5005 Interface	Interface	500	($2.7)	($4.0)	($0.0)	$1.3	($0.2)	$0.2	($0.0)	($0.4)	$0.9	1,512	386
Branchburg - Readington	Line	PSEG	($1.8)	($2.8)	$0.0	$1.0	($0.3)	$0.4	($0.0)	($0.7)	$0.3	2,324	721
Axton	Transformer	AEP	($0.3)	($0.5)	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	238	0
Wylie Ridge	Transformer	AP	($2.0)	($2.3)	($0.0)	$0.3	($0.2)	($0.1)	$0.0	($0.1)	$0.2	1,486	685
East	Interface	500	($0.3)	($0.5)	$0.0	$0.2	($0.0)	$0.0	$0.0	($0.0)	$0.2	304	5
AP South	Interface	500	($1.8)	($2.3)	($0.0)	$0.5	($0.1)	$0.2	($0.0)	($0.3)	$0.2	706	133
Eureka - Willow Island	Line	AP	($0.0)	($0.2)	$0.0	$0.2	($0.0)	$0.0	($0.0)	($0.0)	$0.2	239	34
Cloverdale	Transformer	AEP	($0.3)	($0.6)	$0.0	$0.4	($0.1)	$0.1	($0.0)	($0.2)	$0.2	233	152
South Mahwah - Waldwick	Line	PSEG	$0.1	$0.2	($0.0)	($0.1)	$0.1	($0.1)	($0.0)	$0.2	$0.1	304	58
Amos	Transformer	AEP	($0.2)	($0.1)	($0.0)	($0.2)	($0.0)	($0.0)	$0.0	$0.0	($0.1)	311	132
Homer City - Shelocta	Line	PENELEC	$0.1	$0.1	($0.0)	$0.0	$0.1	($0.0)	$0.0	$0.1	$0.1	200	99

DLCO Control Zone

Table 7-48 and Table 7-49 show the constraints with the largest impacts on total congestion cost in the DLCO Control Zone for 2008 and 2007, respectively. In 2008, the AP South constraint was the largest contributor to positive congestion while the Sammis – Wylie Ridge constraint contributed to negative congestion. In 2007, the Bedington – Black Oak and Beaver – Clinton constraints were the largest contributors to positive congestion while the Elrama – Mitchell and Sammis – Wylie Ridge constraints contributed to negative congestion.

Table 7-48 DLCO Control Zone top congestion cost impacts (By facility): Calendar year 2008

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
AP South	Interface	500	($37.3)	($53.7)	$0.7	$17.1	($7.7)	$2.0	$0.0	($9.7)	$7.4	3,572	997
Sammis - Wylie Ridge	Line	AP	($15.5)	($33.8)	($0.1)	$18.2	($16.9)	$7.3	$0.2	($24.0)	($5.8)	1,915	1,239
Bedington - Black Oak	Interface	500	($13.3)	($19.0)	$0.3	$6.0	($1.2)	$0.7	$0.0	($1.9)	$4.1	1,384	279
Krendale - Seneca	Line	AP	($5.2)	($8.8)	($0.0)	$3.7	($0.1)	$0.0	$0.0	($0.1)	$3.6	1,389	24
Cloverdale - Lexington	Line	AEP	($11.3)	($17.8)	$0.2	$6.7	($2.8)	$1.0	($0.0)	($3.9)	$2.8	3,529	1,739
Cheswick - Universal	Line	DLCO	($1.3)	($3.7)	$0.0	$2.4	$0.1	$0.3	($0.0)	($0.2)	$2.3	411	158
Beaver - Clinton	Line	DLCO	$0.8	($1.1)	$0.0	$1.9	$0.0	$0.0	$0.0	$0.0	$1.9	184	0
Mount Storm	Transformer	AP	($6.9)	($10.1)	($0.0)	$3.2	($3.1)	$1.7	$0.0	($4.8)	($1.6)	935	373
Central	Interface	500	($2.0)	($3.3)	($0.0)	$1.3	($0.1)	$0.0	$0.0	($0.1)	$1.2	726	42
Cheswick - Evergreen	Line	DLCO	$0.4	($1.3)	$0.0	$1.7	($0.2)	$0.4	$0.0	($0.5)	$1.1	94	130
Crescent	Transformer	DLCO	$0.0	$0.0	$0.0	$0.0	$0.7	($0.3)	($0.0)	$1.0	$1.0	0	33
East	Interface	500	($1.3)	($2.2)	$0.0	$0.9	($0.0)	$0.0	$0.0	($0.0)	$0.9	758	12
Mount Storm - Pruntytown	Line	AP	($21.6)	($31.3)	$0.1	$9.8	($5.6)	$3.3	$0.0	($9.0)	$0.8	2,559	722
Kammer	Transformer	500	($4.7)	($6.7)	$0.0	$2.0	($1.2)	$0.0	($0.0)	($1.2)	$0.8	3,069	1,567
West	Interface	500	($10.2)	($13.5)	$0.1	$3.3	($1.6)	$1.0	$0.0	($2.5)	$0.8	1,690	385

Table 7-49 DLCO Control Zone top congestion cost impacts (By facility): Calendar year 2007

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Bedington - Black Oak	Interface	500	($59.8)	($83.1)	($0.1)	$23.2	($7.4)	$4.9	$0.0	($12.3)	$10.9	5,493	1,836
Beaver - Clinton	Line	DLCO	$1.5	($5.3)	$0.1	$6.8	$0.4	($0.1)	$0.0	$0.5	$7.3	451	43
Elrama - Mitchell	Line	AP	($14.3)	($15.0)	($0.1)	$0.6	($3.5)	$3.3	$0.1	($6.7)	($6.2)	1,883	784
Carson - Homested	Line	DLCO	$2.9	($1.7)	$0.0	$4.7	($0.0)	$0.0	$0.0	($0.0)	$4.6	253	2
Cloverdale - Lexington	Line	AEP	($6.6)	($13.1)	$0.0	$6.6	($1.9)	$0.2	($0.0)	($2.0)	$4.5	3,704	1,885
Wylie Ridge	Transformer	AP	($11.5)	($20.0)	($0.0)	$8.6	($3.9)	$0.5	$0.0	($4.4)	$4.2	1,486	685
5004/5005 Interface	Interface	500	($11.5)	($16.4)	($0.0)	$4.9	($1.0)	$0.4	$0.0	($1.4)	$3.5	1,512	386
Branchburg - Readington	Line	PSEG	($6.5)	($9.8)	($0.0)	$3.3	($1.0)	$0.1	$0.0	($1.0)	$2.3	2,324	721
Sammis - Wylie Ridge	Line	AP	($0.3)	($1.0)	$0.0	$0.7	($2.3)	$0.6	$0.0	($2.9)	($2.2)	90	109
Central	Interface	500	($3.8)	($5.9)	($0.0)	$2.1	($0.0)	$0.0	$0.0	($0.0)	$2.1	1,334	25
Cheswick - Evergreen	Line	DLCO	($0.4)	($2.6)	$0.0	$2.3	$0.1	$0.2	$0.0	($0.2)	$2.1	300	102
Brunot Island - Montour	Line	DLCO	$1.6	($0.6)	$0.0	$2.2	($0.1)	$0.1	($0.0)	($0.3)	$1.9	88	42
Crescent - Neville Tap	Line	DLCO	$0.8	($0.9)	$0.0	$1.7	($0.1)	($0.1)	($0.0)	$0.1	$1.8	100	44
Kammer	Transformer	500	($1.0)	($3.3)	$0.0	$2.3	($0.7)	($0.1)	($0.0)	($0.6)	$1.7	2,005	947
Unclassified	Unclassified	Unclassified	$1.2	($0.3)	$0.0	$1.5	$0.0	$0.0	$0.0	$0.0	$1.5	NA	NA

Southern Region Congestion-Event Summaries

Dominion Control Zone

Table 7-50 and Table 7-51 show the constraints with the largest impacts on total congestion cost in the Dominion Control Zone for 2008 and 2007, respectively. In 2008, the AP South interface, the Cloverdale – Lexington line and the Bedington – Black Oak interface constraints were the largest contributors to positive congestion while the Mount Storm transformer, the Dickerson – Pleasant View line and the East interface constraints were the largest contributors to negative congestion. In 2007, the Bedington – Black Oak interface, the Cloverdale – Lexington line and the AP South interface constraints had been the largest contributors to positive congestion while the Branchburg – Readington constraint contributed to negative congestion.

Table 7-50 Dominion Control Zone top congestion cost impacts (By facility): Calendar year 2008

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
AP South	Interface	500	$82.8	($94.7)	$4.6	$182.2	$6.3	$7.8	($3.6)	($5.1)	$177.1	3,572	997
Cloverdale - Lexington	Line	AEP	$111.7	$45.7	$11.5	$77.5	($0.4)	($8.5)	($10.3)	($2.1)	$75.3	3,529	1,739
Bedington - Black Oak	Interface	500	$34.0	$18.4	$1.9	$17.5	$0.3	($1.0)	($0.8)	$0.6	$18.1	1,384	279
Mount Storm	Transformer	AP	$21.4	$8.6	$3.9	$16.7	($8.8)	$16.4	($4.4)	($29.6)	($12.9)	935	373
Aqueduct - Doubs	Line	AP	$9.3	($2.8)	$0.2	$12.3	$0.0	($0.0)	($0.0)	$0.0	$12.3	307	7
Bristers - Ox	Line	Dominion	($1.2)	($12.4)	($0.6)	$10.7	$0.8	$1.1	$0.4	$0.1	$10.8	77	34
Dickerson - Plesant View	Line	Pepco	($12.6)	($4.6)	($0.3)	($8.2)	($0.2)	$0.9	$0.3	($0.7)	($8.9)	844	218
Mount Storm - Pruntytown	Line	AP	$60.1	$62.2	$6.9	$4.8	($4.3)	($14.8)	($6.7)	$3.9	$8.7	2,559	722
Meadow Brook	Transformer	AP	($0.7)	($6.8)	($0.1)	$6.1	($0.1)	$0.3	$0.1	($0.3)	$5.8	774	173
Kammer	Transformer	500	$16.7	$14.0	$1.8	$4.5	($0.1)	($3.2)	($1.9)	$1.1	$5.6	3,069	1,567
Danville - East Danville	Line	Dominion	$4.9	$2.0	$0.2	$3.1	($0.2)	($0.2)	$0.3	$0.3	$3.4	692	141
East	Interface	500	($5.6)	($2.7)	($0.4)	($3.3)	$0.0	$0.0	$0.0	($0.0)	($3.3)	758	12
Brighton	Transformer	Pepco	$3.8	$1.0	$0.2	$3.1	($0.2)	($0.8)	($0.5)	$0.2	$3.3	116	78
Unclassified	Unclassified	Unclassified	$2.1	($0.9)	$0.2	$3.3	($0.0)	($0.0)	($0.0)	($0.0)	$3.3	NA	NA
Pleasantville - Ashburn	Line	Dominion	$3.2	$0.2	$0.0	$3.1	$0.0	$0.0	$0.0	$0.0	$3.1	10	0

Table 7-51 Dominion Control Zone top congestion cost impacts (By facility): Calendar year 2007

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Bedington - Black Oak	Interface	500	$499.0	$414.5	$11.1	$95.6	$0.7	($10.7)	($8.0)	$3.4	$99.0	5,493	1,836
Cloverdale - Lexington	Line	AEP	$217.3	$134.9	$10.9	$93.3	$5.1	$4.6	($7.3)	($6.8)	$86.5	3,704	1,885
AP South	Interface	500	$37.3	$2.4	$0.4	$35.2	$1.5	($0.4)	$0.4	$2.3	$37.5	706	133
Meadow Brook	Transformer	AP	($5.1)	($14.4)	($0.2)	$9.0	$0.1	($0.1)	$0.0	$0.2	$9.2	868	233
Kammer	Transformer	500	$39.7	$34.4	$1.6	$6.8	$0.2	($1.3)	($1.2)	$0.3	$7.1	2,005	947
Bedington	Transformer	AP	$19.1	$13.3	$0.5	$6.3	($0.1)	($1.1)	($0.4)	$0.6	$6.9	928	429
Branchburg - Readington	Line	PSEG	($58.4)	($52.1)	($0.3)	($6.5)	$1.4	$2.1	$0.6	($0.0)	($6.6)	2,324	721
5004/5005 Interface	Interface	500	($13.6)	($18.7)	$0.4	$5.4	$0.2	$0.4	$0.2	$0.1	$5.5	1,512	386
Central	Interface	500	($28.0)	($23.8)	($0.2)	($4.4)	($0.0)	$0.0	$0.0	($0.0)	($4.4)	1,334	25
Cloverdale	Transformer	AEP	$9.8	$6.3	$0.4	$3.9	$0.6	($0.2)	($0.4)	$0.4	$4.3	233	152
Wylie Ridge	Transformer	AP	$14.4	$11.0	$0.8	$4.3	($0.1)	($0.3)	($0.3)	($0.1)	$4.2	1,486	685
Halifax - Clover	Line	Dominion	($0.2)	($4.2)	($0.0)	$4.0	$0.0	$0.0	$0.0	$0.0	$4.0	130	5
Ox	Transformer	Dominion	$2.2	($1.9)	($0.0)	$4.1	$0.6	$0.7	$0.0	($0.1)	$4.0	39	43
Aqueduct - Doubs	Line	AP	$4.4	$1.1	$0.1	$3.4	$0.1	($0.1)	($0.0)	$0.1	$3.5	262	21
Doubs	Transformer	AP	$2.0	($1.3)	($0.0)	$3.3	$0.2	$0.2	$0.0	$0.0	$3.3	135	99

Economic Planning Process

Transmission system investments can be evaluated on a reliability basis or on an economic basis. The reliability evaluation examines whether a transmission upgrade is required in order to maintain reliability on the system in a particular area or areas, using specific planning and reliability criteria.[19] The economic evaluation examines whether a transmission upgrade, including reliability upgrades, results in positive economic benefits. The economic evaluation is more complex than a reliability evaluation because there is more judgment involved in the choice of relevant metrics for both benefits and costs. PJM's responsibility as an RTO requires PJM to constantly evaluate the need for transmission investments related to reliability and to help ensure that the responsible transmission owner constructs needed facilities. As the operator and designer of markets, PJM also needs to consider the appropriate role for the economic evaluation of transmission system investments. Investments in transmission are currently compensated under the FERC's traditional cost of service regulatory approach. Although PJM's Tariff permits merchant projects, the significant merchant transmission projects have been direct current (DC) tie lines to export power rather than investments in network facilities. As a general matter, transmission investments have not been fully incorporated into competitive markets. The construction of new transmission facilities can have significant impacts on energy and capacity markets, but there is no market mechanism in place that would require competition between transmission and generation to meet loads in an area. While the RPM construct does provide that qualifying transmission upgrades may be submitted as offers, there have been no such offers. More generally, network transmission is not built based directly on market signals because the owners of network transmission are compensated through a non-market mechanism. Although the PJM Tariff does not yet comprehensively address the issue of competition between transmission and generation projects to solve congestion problems, PJM has taken a first step towards integrating transmission investments into the market through the use of economic evaluation metrics. Economic evaluation metrics can be used to determine whether there are positive economic benefits associated with an investment in transmission that might warrant the investment even when it is not required for reliability.

PJM has made multiple filings in a proceeding still pending before the Commission that seeks to implement economic metrics for evaluating transmission investments in its Tariff. On September 8, 2006, PJM filed to modify its Regional Transmission Expansion Plan ("RTEP") protocol.[20] PJM proposed to replace its economic planning process with processes that would evaluate the economic benefits of accelerating or modifying planned reliability-based upgrades or of constructing new enhancements or expansions to relieve costly congestion. In its initial order, the FERC conditionally accepted PJM's proposed changes to the economic transmission planning process component of the RTEP, including the requisite amendments to Schedule 6 of the OA and the PJM OATT. The Commission also directed PJM to make a compliance filing that would: (i) explain how PJM considers and weighs the various metrics used to evaluate whether to recommend including an upgrade in the RTEP for economic reasons; (ii) clarify the role of demand response, generation and merchant transmission in the process; and (iii) provide additional information regarding the advanced technologies currently assessed.[21]

19 See PJM OA Schedule 6.
20 PJM Initial Filing, Docket No. ER06-1474-000.
21 117 FERC ¶ 61, 218 (2006).

On March 21, 2007, PJM submitted its first compliance filing, providing further explanation of its metrics.[22] By order issued June 11, 2007, the Commission determined that PJM's proposal was still inadequate and directed PJM to file a formulaic approach to choosing economic projects proposed to reduce congestion that describes exactly how any metrics will be calculated, weighed, considered and combined.[23]

On October 9, 2007, PJM submitted its second compliance filing to address these issues, proposing a formulaic approach modeled on one developed by the Midwest ISO.[24] By order issued April 17, 2008, the FERC largely accepted PJM's proposed formulaic approach, but it required that PJM revise its proposal to (i) calculate load payments net of the change in the value of transmission rights, (ii) include more specific descriptions of the method of determining the discount rate and recovery period, and (iii) either reinstate provisions for sensitivity analyses or explain why such analyses are unnecessary.[25] PJM's third compliance filing, submitted June 16, 2008,[26] addressed each of the three issues identified by the Commission in its 2006 order. In addressing the third item, PJM filed a new approach to perform sensitivity analyses. The new approach provides that PJM will perform a sensitivity analysis for projects included in the RTEP on the basis of certain objective criteria, including, but not limited to, the discount rate used to determine the present value of the Total Annual Enhancement Benefit and Total Enhancement Cost, and the annual revenue requirement, including the recovery period, used to determine the Total Enhancement Cost. Such analyses will consider key inputs used in market simulations performed by PJM (such as price forecasts and expected levels of demand response) in order to determine a "Benefit/Cost Ratio." PJM proposes to provide these results to the Transmission Expansion Advisory Committee (TEAC) in order to assist its evaluation. On February 20, 2009, the FERC issued an order accepting PJM's third compliance filing and denying requests for rehearing of its second order on compliance.[27]

The economic planning process creates market based signals for transmission investment and incorporates improvements over the prior process. The most significant improvements are the inclusion of less discretionary metrics and the evaluation of demand side response and generation resources as alternatives to transmission investment. New transmission projects, and the limits of the existing transmission system, can and do have significant impacts on PJM energy and capacity markets. The goal of transmission planning should ultimately be the incorporation of transmission investment decisions into market driven processes as much as possible.

22 PJM submitted its first compliance filing in Subdocket No. ER06-1474-003.
23 119 FERC ¶ 61,265.
24 PJM submitted its second compliance filing in Subdocket No. ER06-1474-004.
25 123 FERC ¶ 61,051.
26 PJM submitted its third compliance filing in Subdocket No. ER06-1474-006.
27 126 FERC ¶ 61,152.

SECTION 8 – FINANCIAL TRANSMISSION AND AUCTION REVENUE RIGHTS

Financial Transmission Rights (FTRs) and Auction Revenue Rights (ARRs) give transmission service customers and PJM members an offset against congestion costs in the Day-Ahead Energy Market. An FTR provides the holder with revenues, or charges, equal to the difference in congestion prices in the Day-Ahead Energy Market across the specific FTR transmission path. An ARR is a related product that provides the holder with revenues, or charges, based on the price differences across the specific ARR transmission path that result from the Annual FTR Auction. FTRs and ARRs provide a hedge against congestion costs, but neither FTRs nor ARRs provide a guarantee that transmission service customers will not pay congestion charges. ARR and FTR holders do not need to physically deliver energy to receive ARR or FTR credits and neither instrument represents a right to the physical delivery of energy.

In PJM, FTRs have been available to network service and long-term, firm, point-to-point transmission service customers as a hedge against congestion costs since the inception of locational marginal pricing (LMP) on April 1, 1998. Effective June 1, 2003, PJM replaced the allocation of FTRs with an allocation of ARRs and an associated Annual FTR Auction.[1] Since the introduction of this auction, FTRs have been available to all transmission service customers and PJM members. Network service and firm point-to-point transmission service customers can take allocated ARRs or the underlying FTRs through a self scheduling process. On June 1, 2007, PJM implemented marginal losses in the calculation of LMP. Since then, FTRs have been valued based on the difference in congestion prices rather than the difference in LMPs.

Firm transmission service customers have access to ARRs/FTRs because they pay the costs of the transmission system that enables firm energy delivery. Firm transmission service customers receive requested ARRs/FTRs to the extent that they are consistent both with the physical capability of the transmission system and with ARR/FTR requests of other eligible customers.

The *2008 State of the Market Report* focuses on the annual ARR allocations, the Annual FTR Auctions and the Monthly Balance of Planning Period FTR Auctions during two FTR/ARR planning periods: the 2007 to 2008 planning period which covers June 1, 2007, through May 31, 2008, and the 2008 to 2009 planning period which covers June 1, 2008, through May 31, 2009. The *2008 State of the Market Report* also analyzes the results of the 2009 to 2012 Long Term FTR Auction that covers three consecutive planning periods: June 1, 2009 through May 31, 2010, June 1, 2010 through May 31, 2011 and June 1, 2011 through May 31, 2012.

1 87 FERC ¶ 61,054 (1999).

Overview

Financial Transmission Rights

Market Structure

- **Supply.** PJM operates an Annual FTR Auction for all control zones in the PJM footprint. PJM conducts Monthly Balance of Planning Period FTR Auctions for the remaining months of the planning period, to allow participants to buy and sell any residual transmission capability. PJM also runs a Long Term FTR Auction for the three consecutive planning years immediately following the planning year during which the Long Term FTR Auction is conducted. The first Long Term FTR Auction was conducted during the 2008 to 2009 planning period and covers three consecutive planning periods between 2009 and 2012. In addition, PJM administers a secondary bilateral market to allow participants to buy and sell existing FTRs. FTR products include FTR obligations and FTR options. FTR options are not available in the Long Term FTR Auction. For each time period, there are three FTR products: 24-hour, on peak and off peak. FTRs have terms varying from one month to three years. FTR supply is limited by the capability of the transmission system to accommodate simultaneously the set of requested FTRs and the numerous combinations of FTRs. The principal binding constraints limiting the supply of FTRs in the 2009 to 2012 Long Term FTR Auction include the East Sayre – North Waverly and the Farmers Valley – Two Mile lines. The principal binding constraints limiting the supply of FTRs in the Annual FTR Auction for the 2008 to 2009 planning period include the Double Toll Gate – Old Chapel line and the AP South Interface.[2] Market participants can also sell FTRs. In the 2009 to 2012 Long Term FTR Auction, total FTR sell offers were 15,757 MW. In the Annual FTR Auction for the 2008 to 2009 planning period, total FTR sell offers were 83,453 MW, down from 117,199 MW during the 2007 to 2008 planning period. In the Monthly Balance of Planning Period FTR Auctions for the first seven months (June through December 2008) of the 2008 to 2009 planning period, there were 1,436,957 MW of FTR sell offers.

- **Demand.** There is no limit on FTR demand in any FTR auction. In the 2009 to 2012 Long Term FTR Auction, total FTR buy bids were 803,911 MW. In the Annual FTR Auction for the 2008 to 2009 planning period, total FTR buy bids were 2,181,273 MW, down from 2,223,687 MW during the 2007 to 2008 planning period. Total FTR self scheduled bids were 72,851 MW for the 2008 to 2009 planning period, an increase from 71,360 MW for the 2007 to 2008 planning period. In the Monthly Balance of Planning Period FTR Auctions for the first seven months (June through December 2008) of the 2008 to 2009 planning period, total FTR buy bids were 7,593,736 MW.

2 During calendar years 2004 and 2005, PJM conducted the phased integration of five control zones. Four of these, American Electric Power (AEP), The Dayton Power & Light Company (DAY), Duquesne Light Company (DLCO) and Dominion, were eligible for direct allocation FTRs during the 2006 to 2007 planning period, but not the 2007 to 2008 or the 2008 to 2009 planning period. For additional information on the integrations, their timing and their impact on the footprint of the PJM service territory, see the *2008 State of the Market Report,* Volume II, Appendix A, "PJM Geography."

- **FTR Credit Issues.** Six participants had FTR related payment obligations in default in 2008. Three of those participants had defaulted on their FTR related payment obligations in 2007. There were four participants who defaulted in 2007, after accounting for collateral. The magnitude of the defaults was the result of both the size of the FTR positions defaulted and of the PJM credit policies, which did not require sufficient collateral to cover the participants' losses. The 2007 defaults made it clear that PJM credit polices related to FTRs and particularly to counter flow FTRs were inadequate. PJM made multiple filings in 2008 to reform its credit policies, focusing particularly on ensuring an appropriate level of credit to cover positions acquired by market participants in counter flow FTRs. The defaults also raised potential market gaming issues, which were addressed, in part, in a PJM filing.[3] These are being investigated.

- **Patterns of Ownership.** The ownership concentration of cleared FTR buy bids resulting from the 2008 to 2009 Annual FTR Auction was low to moderate for FTR obligations and high for FTR options. The level of concentration is only descriptive and is not a measure of the competitiveness of FTR market structure as the ownership positions resulted from a competitive auction. In order to evaluate the ownership of prevailing flow and counter flow FTRs, the Market Monitoring Unit (MMU) categorized all participants owning FTRs 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. Physical entities own more than half of prevailing flow Annual FTRs while financial entities own almost three quarters of counter flow Annual FTRs. The ownership of all Annual FTRs is about evenly split between physical and financial entities. Financial entities own almost two thirds of prevailing flow Long Term FTRs and more than half of counter flow Long Term FTRs. Financial entities own about 61 percent of all Long Term FTRs. Financial entities own two thirds of prevailing flow and about three quarters of counter flow Monthly Balance of Planning Period FTRs. Overall, financial entities own about 70 percent of all Monthly Balance of Planning Period FTRs.

Market Performance

- **Volume.** The 2009 to 2012 Long Term FTR Auction cleared 52,369 MW (6.5 percent of demand) of FTR buy bids and 1,010 MW (6.4 percent) of FTR sell offers. For the 2008 to 2009 planning period, the Annual FTR Auction cleared 204,349 MW (9.4 percent) of FTR buy bids, down from 208,637 MW (9.4 percent of demand) for the 2007 to 2008 planning period. The Annual FTR Auction also cleared 4,534 MW (5.4 percent) of FTR sell offers for the 2008 to 2009 planning period, down from 6,495 MW (5.5 percent) for the 2007 to 2008 planning period. For the first seven months of the 2008 to 2009 planning period, the Monthly Balance of Planning Period FTR Auctions cleared 545,189 MW (7.2 percent) of FTR buy bids and 183,322 MW (12.8 percent) of FTR sell offers.

3 PJM Interconnection, L.L.C. made a filing under section 205 of the Federal Power Act to amend section 15.2 of the PJM Operating Agreement concerning defaults on short FTR portfolios in Docket No. ER08-455-000, (January 18, 2008).

- **Price.** In the 2009 to 2012 Long Term FTR Auction, 90.7 percent of the Long Term FTRs were purchased for less than $1 per MWh and 94.5 percent for less than $2 per MWh. The weighted-average prices paid for Long Term buy-bid FTRs were $0.76 per MWh for 24-hour FTRs, $0.10 per MWh for on peak FTRs and $0.01 per MWh for off peak FTRs. For the 2008 to 2009 planning period, 83.5 percent of the Annual FTRs were purchased for less than $1 per MWh and 88.8 percent for less than $2 per MWh. For the 2008 to 2009 planning period, the weighted-average prices paid for annual buy-bid FTR obligations were $1.96 per MWh for 24-hour FTRs, $0.55 per MWh for on peak FTRs and $0.26 per MWh for off peak FTRs. Comparable, weighted-average prices paid for annual buy-bid FTR obligations for the 2007 to 2008 planning period were $0.35 per MWh for 24-hour FTRs and $0.57 per MWh for on peak FTRs and $0.47 per MWh for off peak FTRs. The weighted-average prices paid for 2008 to 2009 planning period annual buy-bid FTR obligations and options were $0.69 per MWh and $0.24 per MWh, respectively, compared to $0.47 per MWh and $0.37 per MWh, respectively, in the 2007 to 2008 planning period.[4] The weighted-average price paid for buy-bid FTRs in the Monthly Balance of Planning Period FTR Auctions for the first seven months of the 2008 to 2009 planning period was $0.35 per MWh, compared with $0.21 per MWh in the Monthly Balance of Planning Period FTR Auctions for the full 12-month 2007 to 2008 planning period.

- **Revenue.** The 2009 to 2012 Long Term FTR Auction generated $38.93 million of net revenue for all FTRs. The Annual FTR Auction generated $2,422.55 million of net revenue for all FTRs during the 2008 to 2009 planning period, up from $1,698.03 million for the 2007 to 2008 planning period. The Monthly Balance of Planning Period FTR Auctions generated $62.2 million in net revenue for all FTRs during the first seven months of the 2008 to 2009 planning period.

- **Revenue Adequacy.** FTRs were 100 percent revenue adequate for the 2007 to 2008 planning period. FTRs were paid at 99.6 percent of the target allocation level for the first seven months of the 2008 to 2009 planning period. Congestion revenues are allocated to FTR holders based on FTR target allocations. PJM collected $1,354.8 million of FTR revenues during the first seven months of the 2008 to 2009 planning period and $2,059.2 million during the 2007 to 2008 planning period. For the first seven months of the 2008 to 2009 planning period, the top sink and top source with the highest positive FTR target allocations were the AP Control Zone and the Western Hub, respectively. Similarly, the top sink and top source with the largest negative FTR target allocations were the Northern Illinois Hub and the Pepco Control Zone, respectively.

4 Weighted-average prices for FTRs in the Long Term FTR Auction, Annual FTR Auction and Monthly Balance of Planning Period FTR Auctions are the average prices weighted by the MW and hours in a time period (planning period or month) for each FTR class type: 24-hour, on peak and off peak. For example, FTRs in the 2008 to 2009 Annual FTR Auction would be weighted by their MW and the hours in that time period for each FTR class type: 24-hour (8,760 hours), on peak (4,064 hours) and off peak (4,696 hours).

Auction Revenue Rights

Market Structure

- **Supply.** ARR supply is limited by the capability of the transmission system to simultaneously accommodate the set of requested ARRs and the numerous combinations of feasible ARRs. The principal binding constraints that limited supply in the annual ARR allocation for the 2008 to 2009 planning period were the AP South Interface and the Cedar Grove — Clifton line. A new ARR product was added for the 2007 to 2008 planning period. Long Term ARRs are in effect for 10 consecutive planning periods and are available in Stage 1A of the annual ARR allocation. Residual ARRs were also introduced and are available to holders with prorated Stage 1A or 1B ARRs if additional transmission capability is added during the planning period.

- **Demand.** Total demand in the annual ARR allocation was 140,668 MW for the 2008 to 2009 planning period with 64,546 MW bid in Stage 1A, 27,291 MW bid in Stage 1B and 48,831 MW bid in Stage 2. This is down from 150,822 MW for the 2007 to 2008 planning period with 62,220 MW bid in Stage 1A, 31,063 MW bid in Stage 1B and 57,539 MW bid in Stage 2. ARR demand is limited by the total amount of network service and firm point-to-point transmission service.

- **ARR Reassignment for Retail Load Switching.** When retail load switches among load-serving entities (LSEs), a proportional share of the ARRs and their associated revenue are reassigned from the LSE losing load to the LSE gaining load. ARR reassignment occurs only if the LSE losing load has ARRs with a net positive economic value. An LSE gaining load in the same control zone is allocated a proportional share of positively valued ARRs within the control zone based on the shifted load. There were 10,017 MW of ARRs associated with approximately $353,300 per MW-day of revenue that were reassigned in the first seven months of the 2008 to 2009 planning period.

Market Performance

- **Volume.** Of 140,668 MW in ARR requests for the 2008 to 2009 planning period, 112,011 MW (79.6 percent) were allocated. There were 64,520 MW allocated in Stage 1A, 26,685 MW allocated in Stage 1B and 20,806 MW allocated in Stage 2. Eligible market participants self scheduled 72,851 MW (65.0 percent) of these allocated ARRs as Annual FTRs. Of 150,822 MW in ARR requests for the 2007 to 2008 planning period, 107,992 MW (71.6 percent) were allocated. There were 62,211 MW allocated in Stage 1A, 29,444 MW allocated in Stage 1B and 16,337 MW allocated in Stage 2. Eligible market participants self scheduled 71,360 MW (66.1 percent) of these allocated ARRs as Annual FTRs.

- **Revenue.** As ARRs are allocated to qualifying customers rather than sold, there is no ARR revenue comparable to the revenue that results from the FTR auctions.

- **Revenue Adequacy.** During the 2008 to 2009 planning period, ARR holders will receive $2,361.3 million in ARR credits, with an average hourly ARR credit of $2.41 per MWh. During the 2008 to 2009 planning period, the ARR target allocations were $2,361.3 million while PJM collected $2,484.8 million from the combined Annual and Monthly Balance of Planning Period FTR Auctions through December 31, 2008, making ARRs revenue adequate. During the 2007 to 2008 planning period, ARR holders received $1,640.5 million in ARR credits, with an average hourly ARR credit of $1.73 per MWh. For the 2007 to 2008 planning period, the ARR target allocations were $1,640.5 million while PJM collected $1,736.1 million from the combined Annual and Monthly Balance of Planning Period FTR Auctions, making ARRs revenue adequate.

- **ARR Proration.** When ARRs were allocated for the 2008 to 2009 planning period, some of the requested ARRs were prorated as a result of binding transmission constraints. For the 2008 to 2009 planning period, no ARRs were prorated in Stage 1A of the annual ARR allocation. In Stage 1B, the only constraint affecting the ARR allocation was the Cedar Grove — Clifton line. There were 605.4 MW of Stage 1B ARRs denied to participants whose requested ARRs affected that binding transmission constraint. For the 2007 to 2008 planning period, no ARRs were prorated in Stage 1A of the annual ARR allocation. In Stage 1B, the only constraint affecting the ARR allocation was the Cedar Grove — Clifton line. There were 1,159.3 MW of Stage 1B ARRs denied to participants whose requested ARRs affected that binding transmission constraint.

- **ARRs and FTRs as a Hedge Against Congestion.** The effectiveness of ARRs and FTRs as a hedge against actual congestion can be measured several ways. The first is to compare the revenue received by ARR holders to the congestion costs experienced by these ARR holders. The second is to compare the revenue received by FTR holders to the total congestion costs within PJM. The final and comprehensive method is to compare the revenue received by all ARR and FTR holders to total actual congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM. During the 2007 to 2008 planning period, total ARR and FTR revenues hedged 97.4 percent of the congestion costs within PJM. For the first seven months of the 2008 to 2009 planning period, all ARRs and FTRs hedged 97.2 percent of the congestion costs within PJM.

Conclusion

The annual ARR allocation and the FTR auctions provide market participants with hedging instruments. These instruments can be used for hedging positions or for speculation. The Long Term FTR Auction, the Annual FTR Auction and the Monthly Balance of Planning Period FTR Auctions provide a market valuation of FTRs. The FTR auction results for the 2008 to 2009 planning period were competitive and succeeded in providing all qualified market participants with equal access to FTRs. The MMU recommends that the rules for ARR reassignment when load shifts should address the fact that in the case of ARRs self scheduled as FTRs, the underlying FTRs do not follow the load while the ARRs do.

ARRs were 100 percent revenue adequate for both the 2007 to 2008 and the 2008 to 2009 planning periods. FTRs were paid at 100 percent of the target allocation level for the 12-month period of the 2007 to 2008 planning period, and at 99.6 percent of the target allocation level for the first seven months of the 2008 to 2009 planning period.

The total of ARR and FTR revenues hedged 97.4 percent of the congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM for the 2007 to 2008 planning period and 97.2 percent of the congestion costs in PJM in the first seven months of the 2008 to 2009 planning period. The ARR and FTR revenue adequacy results are aggregate results and all those paying congestion charges were not necessarily hedged at that level. Aggregate numbers do not reveal the underlying distribution of FTR holders, their revenues or those paying congestion.

Revenue adequacy must be distinguished from the adequacy of FTRs as a hedge against congestion. Revenue adequacy is a narrower concept that compares the revenues available to cover congestion across specific paths for which FTRs were available and purchased. The adequacy of FTRs as a hedge against congestion compares FTR revenues to total congestion on the system as a measure of the extent to which FTRs hedged market participants against actual, total congestion across all paths, regardless of the availability or purchase of FTRs.

PJM faced substantial participant defaults in 2007 and 2008 as a result of participant counter flow positions in the FTR markets and inadequate participant financial resources. The magnitude of the defaults was the result of both the size of the FTR positions defaulted and of the PJM credit policies, which did not require sufficient collateral to cover the participants' losses. PJM also faced additional defaults in 2008. PJM has taken steps to address the credit issue. The defaults also raised potential market gaming issues, which were addressed, in part, in a PJM filing. These are being investigated.

Financial Transmission Rights

While FTRs have been available to eligible participants since the 1998 introduction of LMP, the Annual FTR Auction was first implemented for the 2003 to 2004 planning period. Since the 2006 to 2007 planning period, the auction has covered all control zones.

FTRs are financial instruments that entitle their holders to receive revenue or require them to pay charges based on locational congestion price differences in the Day-Ahead Energy Market across specific FTR transmission paths. Effective June 1, 2007, PJM added marginal losses as a component in the calculation of LMP.[5] The value of an FTR reflects the difference in congestion prices rather than the difference in LMPs, which includes both congestion and marginal losses. Auction market participants are free to request FTRs between any pricing nodes on the system, including hubs, control zones, aggregates, generator buses, load buses and interface pricing points. FTRs are available to the nearest 0.1 MW. The FTR target allocation is calculated hourly and is equal to the product of the FTR MW and the congestion price difference between sink and source that occurs in the Day-Ahead Energy Market. The value of an FTR can be positive or negative depending on the sink minus source congestion price difference, with a negative difference resulting in a liability for the holder. The FTR target allocation represents what the holders would receive if sufficient revenues are collected to fund FTRs.

Depending on the amount of FTR revenues collected, FTR holders with a positively valued FTR may receive congestion credits between zero and their target allocations. FTR holders with a negatively valued FTR are required to pay charges equal to their target allocations. When FTR holders receive

5 For additional information on marginal losses, see the *2008 State of the Market Report*, Volume II, Section 2, "Energy Market, Part 1," at "Real-Time Annual LMP Loss Component."

their target allocations, the associated FTRs are fully funded. The objective function of all FTR auctions is to maximize the bid-based value of FTRs awarded in each auction.

FTRs can be bought, sold and self scheduled. Buy bids are FTRs that are bought in the auctions; sell offers are existing FTRs that are sold in the auctions; and self scheduled bids are FTRs that have been directly converted from ARRs.

There are two FTR hedge type products: obligations and options. An obligation provides a credit, positive or negative, equal to the product of the FTR MW and the congestion price difference between FTR sink (destination) and source (origin) that occurs in the Day-Ahead Energy Market. An option provides only positive credits and options are available for only a subset of the possible FTR transmission paths.

There are three FTR class type products: 24-hour, on peak and off peak. The 24-hour products are effective 24 hours a day, seven days a week, while the on peak products are effective during on peak periods defined as the hours ending 0800 through 2300, Eastern Prevailing Time (EPT) Mondays through Fridays, excluding North American Electric Reliability Council (NERC) holidays. The off peak products are effective during hours ending 2400 through 0700, EPT, Mondays through Fridays, and during all hours on Saturdays, Sundays and NERC holidays.

FTR buy bids and sell offers may be made as obligations or options and as any of the three class types. FTR self scheduled bids are available only as obligations and 24-hour class types, consistent with the associated ARRs.

Market Structure

Prior to implementation of the Annual FTR Auction, only network service and long-term, firm, point-to-point transmission service customers were able to directly obtain Annual FTRs. Now all transmission service customers and PJM members can participate in the Long Term FTR Auction, the Annual FTR Auction and the Monthly Balance of Planning Period FTR Auctions.

Supply

Throughout the year, PJM oversees the process of selling and buying FTRs through FTR Auctions. Market participants purchase FTRs by participating in Long Term, Annual and Monthly Balance of Planning Period FTR Auctions.[6] The Annual FTR Auction includes the ability to directly convert allocated ARRs into self scheduled FTRs. Total FTR supply is limited by the capability of the transmission system to simultaneously accommodate the set of requested FTRs and the numerous combinations of FTRs that are feasible. For the Annual FTR Auction, known transmission outages that are expected to last for two months or more are included, while known outages of five days or more are included for the Monthly Balance of Planning Period FTR Auctions as well as any outages of a shorter duration that PJM determines would cause FTR revenue inadequacy if not modeled.[7] But, the auction process does not account for the fact that significant transmission outages, which have not been provided to PJM by transmission owners prior to the auction date, will occur during

6 PJM. "Manual 6: Financial Transmission Rights," Revision 11 (August 1, 2008), p. 34.
7 PJM. "Manual 6: Financial Transmission Rights," Revision 11 (August 1, 2008), p. 49.

the periods covered by the auctions. Such transmission outages may not be planned in advance or may be emergency in nature. FTRs can be traded between market participants through bilateral transactions.

During the 2008 to 2009 planning period, binding transmission constraints prevented the award of all requested FTRs in the Long Term FTR Auction, the Annual FTR Auction and Monthly Balance of Planning Period FTR Auctions.[8] Table 8-1 and Table 8-2 list the top 10 binding constraints along with their corresponding control zones in the Long Term FTR Auction and the Annual FTR Auction, respectively. They are listed in order of severity, irrespective of auction round. For each of the top 10 binding constraints, a numerical ranking in order of severity for each auction round is also listed. The order of severity is determined by the marginal value of the binding constraint. The marginal value measures the value gained by relieving a constraint by 1 MW. The marginal value is computed and generated in the optimization engine for both on peak and off peak hours.[9] Table 8-1 and Table 8-2 demonstrate the marginal value for on peak hours only.

Table 8-1 Top 10 principal binding transmission constraints limiting the Long Term FTR Auction: Planning periods 2009 to 2012[10]

			Severity Ranking by Auction Round	
Constraint	Type	Control Zone	1	2
East Sayre - North Waverly	Line	PENELEC	NA	1
Farmers Valley - Two Mile	Line	PENELEC	59	2
Branchburg - Readington	Line	PSEG	1	4
Lewis - Motts - Cedar	Line	AECO	2	5
Doubs - Mount Storm	Line	500	3	3
Roseland	Transformer	PSEG	4	NA
Branchburg	Transformer	PSEG	5	9
Montezuma-Bondurant	Flowgate	External	6	40
Rising	Flowgate	External	7	6
Arnold-Hazleton	Flowgate	External	45	7

8 Binding constraints for Monthly Balance of Planning Period Auctions are posted to the PJM Web site in monthly files at http://www.pjm.com/markets-and-operations/ftr/auction-user-info/historical-ftr-auction.aspx.

9 PJM. "Manual 6: Financial Transmission Rights," Revision 11 (August 1, 2008), p. 52.

10 The transmission facilities that were not constrained during a certain auction round are listed as NA (not applicable).

Table 8-2 Top 10 principal binding transmission constraints limiting the Annual FTR Auction: Planning period 2008 to 2009[11]

			Severity Ranking by Auction Round			
Constraint	Type	Control Zone	1	2	3	4
Double Toll Gate - Old Chapel	Line	AP	NA	5	1	1
AP South	Interface	AP	2	1	2	2
Bedington - Black Oak	Interface	AP	1	3	5	4
Krendale - Seneca	Line	AP	15	10	3	7
Bedington	Transformer	AP	3	2	4	3
Doubs	Transformer	AP	4	4	6	5
Quinton - Roadstown	Line	AECO	10	6	33	22
Kammer	Transformer	AEP	5	7	7	6
East Towanda	Transformer	PENELEC	6	8	9	13
Mahans Lane - Weirton	Line	AP	13	13	11	8

Long Term FTR Auction

During the 2008 to 2009 planning period, a new Long Term FTR Auction was introduced.[12] PJM conducts a Long Term FTR Auction for the three consecutive planning periods immediately following the planning period during which the Long Term FTR Auction is conducted. The capacity offered for sale in Long Term FTR Auctions is the residual system capability after the assumption that all ARRs allocated in the immediately prior annual ARR allocation process are self scheduled as FTRs. These ARRs are modeled as fixed injections and withdrawals in the Long Term FTR Auction. Future transmission upgrades are not included in the model. The Long Term FTR Auction consists of two rounds. In each round 50 percent of the feasible FTR available capability is awarded.[13]

- **Round 1.** The first round is conducted approximately 11 months prior to the start of the term covered by the Long Term FTR Auction. Market participants make offers for FTRs between any source and sink. These offers can be 24-hour, on peak or off peak FTR obligations. FTR option products are not available in Long Term FTR Auctions.

- **Round 2.** The second round is conducted approximately 4 months after the first round. FTRs purchased in the first round may be offered for sale in the second round.[14]

FTRs obtained in the Long Term Auctions may have terms of one year or a term of three years.

11 The Double Toll Gate – Old Chapel line was not constrained during the first auction round and is listed as NA (not applicable).
12 *PJM Interconnection, L.L.C.*, PJM Interconnection, L.L.C. submits revisions to its Open Access Transmission Tariff and the Amended and Restated Operating Agreement pursuant to Section 205 of the Federal Power Act. The proposed revisions modify the FTR auction rules in the PJM Interchange Energy Market by establishing a Long Term FTR Auction process, Docket No. ER08-1016-000, (May 28, 2008).
13 PJM. "Manual 6: Financial Transmission Rights," Revision 11 (August 1, 2008), p. 34.
14 PJM. "Manual 6: Financial Transmission Rights," Revision 11 (August 1, 2008), p. 37.

Annual FTR Auction

Each April, PJM conducts an Annual FTR Auction during which all eligible market participants may bid on FTRs for the next planning period consistent with total transmission system capability, excluding the FTRs approved in prior Long Term FTR Auctions. The auction takes place over four rounds with 25 percent of the feasible transmission system capability awarded in each round:

- **Round 1.** Market participants make offers for FTRs between any source and sink. These offers can be 24-hour, on peak or off peak FTR obligations or FTR options. Locational prices are determined by maximizing the net revenue based on offer-based value of FTRs.[15] Any transmission service customer or PJM member can bid for available FTRs. ARR holders wishing to directly convert their previously allocated ARRs into self scheduled FTRs must initiate that process in this round. One quarter of each self scheduled FTR clears as a 24-hour FTR in each of the four rounds. Self scheduled FTRs must have the same source and sink as the corresponding ARR. Self scheduled FTRs clear as price-taking FTR bids that are not eligible to set auction price.

- **Rounds 2 to 4.** Market participants make offers for FTRs. Locational prices are determined by maximizing the offer-based value of FTRs cleared. FTRs purchased in earlier rounds can be offered for sale in later rounds.

By self scheduling ARRs as price-taking bids in the Annual FTR Auction, customers with ARRs receive FTRs for their ARR paths. ARR holders are guaranteed that they will receive their requested FTRs. ARRs can be self scheduled only as 24-hour FTR obligations. ARR holders that self schedule ARRs as FTRs still hold the associated ARR. Self scheduling transactions net out such that the ARR holder buys the FTR in the auction, receives the corresponding revenue based on holding the ARR and is left with ownership of the FTR as a hedge. The following is an illustrative example of self scheduling ARRs as FTRs. An ARR holder has received an allocation of 1 MW from source A to sink B. The ARR holder self schedules the 1 MW allocated ARR as an FTR. In the Annual FTR Auction, the price for a 1 MW FTR from A to B is $100. The ARR holder pays $100 to buy the 1 MW FTR in the Annual FTR Auction, but receives a $100 ARR target credit based on the associated 1 MW ARR. In addition, the ARR holder obtains the corresponding FTR target allocation as a hedge.

Monthly Balance of Planning Period FTR Auctions

The Monthly Balance of Planning Period FTR Auctions make available the residual FTR capability on the PJM transmission system after the Long Term and Annual FTR Auctions are concluded. They are single-round monthly auctions that allow any transmission service customers or PJM members to bid for any FTR or to offer for sale any FTR that they currently hold. Market participants can bid for or offer monthly FTRs for any of the next three months remaining in the planning period, or quarterly FTRs for any of the quarters remaining in the balance of the planning period. FTRs in the auctions can be either obligations or options and can be 24-hour, on peak or off peak products.[16]

15 Long Term, Annual and Monthly Balance of Planning Period FTR Auctions determine nodal prices as a function of market participants' FTR bids and binding transmission constraints. An optimization algorithm selects the set of feasible FTR bids that produces maximum net revenue, thus maximizing the value of transmission assets. A feasible set of FTR bids is a set that does not impose a flow on any transmission facility in excess of its rating.

16 PJM. "Manual 6: Financial Transmission Rights," Revision 11 (August 1, 2008), pp. 34-35.

Under the auction rules, market participants may bid to buy or offer to sell FTRs that have the following two terms. The first term is for one month for any of the next three months remaining in the planning period. For example, if the auction is conducted in May, any FTR valid for the months of June, July and August is included in the auction. The second term is for three months for any of the quarters remaining in the planning period (if technically feasible within the specified market time frame). For example, for planning period quarter 1 (Q1), the auction period would be June, July and August. For planning period quarter 2 (Q2), the auction period would be September, October and November. Similarly, December, January and February would be for planning period quarter 3 (Q3) and March, April and May would be for planning period quarter 4 (Q4). For example, an auction held in May would have all four quarters available, while an auction held in June would include quarter 2, quarter 3 and quarter 4, but not quarter 1.

Secondary Bilateral Market

Market participants can buy and sell existing FTRs through the PJM-administered, bilateral market, or market participants can trade FTRs among themselves without PJM involvement. Bilateral transactions that are not done through PJM can involve parties that are not PJM members. PJM has no knowledge of bilateral transactions that are done outside of PJM's secondary bilateral market system.

For bilateral trades done through PJM, the FTR transmission path must remain the same; FTR obligations must remain obligations and FTR options must remain options. However, an individual FTR may be split up into multiple, smaller FTRs, down to increments of 0.1 MW. FTRs can also be given different start and end times, but the start time cannot be earlier than the original FTR start time and the end time cannot be later than the original FTR end time.

Demand

Under current rules, participants may submit unlimited bids for FTRs for any single auction round in the Annual FTR Auction or for any single Monthly Balance of Planning Period FTR Auction.

FTR Credit Issues

Default

Six participants had FTR related payment obligations in default in 2008. Three of those participants had defaulted on their FTR related payment obligations in 2007. There were four participants who defaulted in 2007, after accounting for collateral. The magnitude of the defaults was the result of both the size of the FTR positions defaulted and of the PJM credit policies, which did not require sufficient collateral to cover the participants' losses. The 2007 defaults made it clear that PJM credit polices related to FTRs and particularly to counter flow FTRs were inadequate. PJM made multiple filings in 2008 to reform its credit policies, focusing particularly on ensuring an appropriate level of credit to cover positions acquired by market participants in counter flow FTRs. The defaults also raised potential market gaming issues, which were addressed, in part, in a PJM filing.[17] These are being investigated.

In October 2007, Exel Power Sources, L.L.C. defaulted on September obligations and subsequently defaulted on obligations, including some in 2008, with a total net default value of approximately $5.3 million, after collateral. In December 2007, Power Edge, L.L.C. defaulted on November obligations and subsequently defaulted on additional obligations in 2008 with a total default value of about $51.8 million, not accounting for the related funds currently held by PJM. Del Light, Inc. and PJS Capital, L.L.C. also defaulted in January 2008, with total net default value of about $0.2 million and $0.6 million.[18] Chien Energy and Lehman Brothers Commodity Service, Inc. defaulted with total net default values of about $80,000 and $14.6 million respectively.

The defaults made it clear that PJM credit polices related to FTRs and particularly to counter flow FTRs were inadequate. The defaults also raised potential market gaming issues, which were addressed, in part, in a PJM filing.[19] These are being investigated.

Prevailing flow FTRs hedge congestion on a path. Participants purchase prevailing flow FTRs for a positive price with the expectation that the FTR revenues will exceed the cost of the FTRs. Counter flow FTRs expose the owner to paying congestion on a path. Participants receive a payment to take counter flow FTRs with the expectation that the payment will exceed the FTR charges they must pay. The risk of a prevailing flow FTR is generally limited to the purchase price, although risk could increase if congestion reversed. The risk of a counter flow FTR derives from the underlying congestion and is, therefore, not limited to a fixed payment. The risk is substantially greater for a counter flow FTR than for a prevailing flow FTR.

FTR Credit Rules

Under credit rules in place during 2007, PJM required participants in FTR auctions to meet defined credit requirements linked to the value of the FTRs. PJM calculated the FTR credit requirement for each market participant using FTR cost and a measure of the historical congestion on the FTR path for the planning period, discounted by 30 percent. The 30 percent adjustment did not apply to counter flow FTRs. PJM calculated a total FTR credit requirement for each market participant, which must be maintained to participate in the FTR auctions.[20]

On December 20, 2007, PJM notified its members that it had declared Power Edge in default for failure to pay its invoice of December 7, 2007, and estimated that this would create a significant liability for the PJM membership collectively.[21] As a result of the default by Power Edge in December 2007, it became clear that the credit rules were inadequate, particularly with respect to the credit requirements for counter flow FTR positions. PJM had already begun the stakeholder process to modify the credit rules, but the modified rules had not yet been filed with the Commission or approved.

17 PJM Interconnection, L.L.C. made a filing under section 205 of the Federal Power Act to amend section 15.2 of the PJM Operating Agreement concerning defaults on short FTR portfolios in Docket No. ER08-455-000, (January 18, 2008).

18 Additional information on the defaults is available on the PJM Web Site at http://www.pjm.com/about-pjm/member-services/default-notification.aspx.

19 PJM Interconnection, L.L.C. made a filing under section 205 of the Federal Power Act to amend section 15.2 of the PJM Operating Agreement concerning defaults on short FTR portfolios in Docket No. ER08-455-000, (January 18, 2008).

20 For the complete FTR Auction credit business rules, see PJM. "Manual 6: Financial Transmission Rights," Revision 11 (August 1, 2008), pp.38-42.

21 See PJM e-mail notification of the default posted on its Website at: http://www.pjm.com/about-pjm/member-services/~/media/about-pjm/member-services/default-notification/20071220-mc-email-power-edge-default.ashx. Additional updates on this and other credit issues can be found on PJM's Website at: <http://www.pjm.com/about-pjm/member-services/default-notification.aspx>.

PJM filed a complaint with the FERC against Power Edge and its affiliates as well as related claims in the United States District Court for the District of Delaware.[22] PJM continues to retain collateral posted by Power Edge's affiliates and to restrict trading privileges in PJM by such affiliates. In response, Power Edge's affiliates filed suit at the FERC and in the Eastern District of Pennsylvania, seeking an order requiring PJM to return their collateral and restore their trading privileges.[23] All of these proceedings are currently pending.

In an effort to prevent or mitigate the harm from future defaults, PJM has actively sought to reform its credit policies. On December 26, 2007, PJM proposed revisions to improve its credit requirements for FTR market participants, which the Commission approved by order issued March 25, 2008.[24] The revisions changed the calculation period for the FTR credit requirement to a monthly from an annual basis and the calculation and allocation of offsets for ARR credits to monthly rather than annually. The credit calculation sums only the months with positive net credit requirements and applies a generic 10 percent adjustment to historical values of both prevailing flow FTRs and counter flow FTRs to account for likely differences from historical experience.

PJM submitted an additional filing on January 31, 2008, to the FERC to increase the credit requirement for market participants with net counter flow FTR positions, which the Commission also approved in the March 25th Order.[25] PJM's revised policy adds to the credit requirements for net counter flow positions an amount equal to the net price of the portfolio multiplied by two, and if the counter flow position is also not well diversified geographically, multiplied by three instead.

On January 18, 2008, PJM submitted a filing intended to confirm PJM's authority to set off a company's FTR default against FTR market revenues that PJM would otherwise have paid to the defaulting company's affiliates and to apply such affiliates' posted security to the default to the extent that the security relates to the company's FTR positions, but the March 25th Order rejected this proposal.[26]

The credit requirements for Long Term FTRs are the same as the credit requirements for Annual FTRs. The credit requirements are based on each month of each FTR. Long Term FTR credit requirements will be recalculated each year as a new set of historical data is prepared for the upcoming annual auction.[27]

PJM's current tariff rules allow some PJM market participants a significant amount of unsecured credit on the basis of PJM's evaluation of their credit worthiness, following the approved guidelines for this review. The MMU recommends the elimination of unsecured credit, over an appropriate transition period, based on the MMU's view of PJM's role in evaluating the credit worthiness of complex corporate entities and due to a concern about inappropriate shifts of risks and costs among the membership.

22 PJM filed a complaint against Accord Energy LLC, et al., in Docket No. EL08-44-000 (March 7, 2008); PJM filed a complaint and demand for jury trial versus Mark Gorton, et al., in the United States District Court for the District of Delaware in Case No. 1:99-inc-9999 (April 16, 2008).

23 BJ Energy LLC, et al., filed a complaint against PJM in Docket No. EL08-49-000 (April 17, 2008); BJ Energy LLC, et al., filed a first amended complaint versus PJM in the United States District Court for the Eastern District of Pennsylvania in C.A. No. 08-cv-3649-NS (November 7, 2008).

24 PJM filed proposed revisions to the PJM Credit Policy ("Attachment Q") in Docket No. ER08-376-000 (December 26, 2007); *PJM Interconnection, L.L.C.*, 122 FERC ¶ 61,279 ("March 25th Order").

25 PJM filed proposed revisions to Attachment Q in Docket No. ER08-520-000.

26 PJM filed a proposed amendment to PJM OA § 15.2 in Docket No. ER08-455-000.

27 *PJM Interconnection, L.L.C.*, PJM Interconnection, L.L.C. submits revisions to its Open Access Transmission Tariff and the Amended and Restated Operating Agreement pursuant to Section 205 of the Federal Power, Docket No. ER08-1016-000, (May 28, 2008).

On January 3, 2009, PJM proposed tariff revisions that would reduce the per member allowance of unsecured credit by two-thirds, limit the unsecured credit allowance for a family of affiliates to an aggregate $150 million, eliminate unsecured credit allowances for FTR trading activity, shorten settlement periods by transitioning to weekly from monthly billing for invoice line items that represent most of PJM's billings, and allow PJM to close and liquidate a member's FTR positions after a declaration of that member's default.[28] This proposal is currently pending before the FERC.

Patterns of Ownership

The overall ownership structure of FTRs and the ownership of prevailing flow and counter flow FTRs are evaluated.

The ownership concentration of cleared FTR buy bids resulting from the 2008 to 2009 Annual FTR Auction was low to moderate for FTR obligations and high for FTR options. This ownership information is descriptive and is not necessarily a measure of actual or potential FTR market structure issues, as the ownership positions result from competitive auctions. The percentage of FTR ownership shares may change when FTR owners buy or sell FTRs in the Monthly Balance of Planning Period FTR Auctions or secondary bilateral market.

For cleared FTR buy-bid obligations in the 2008 to 2009 Annual FTR Auction, the HHIs were 876 for 24-hour, 1141 for on peak and 1258 for off peak FTR products while maximum market shares were 19 percent for 24-hour, which is associated with a physical entity, 22 percent for on peak, which is associated with a financial entity, and 24 percent for off peak FTR products, which is associated with a financial entity.

For cleared FTR buy-bid options in the 2008 to 2009 Annual FTR Auction, HHIs were 8722 for 24-hour, 2303 for on peak and 2314 for off peak products while maximum market shares were 93 percent for 24-hour, which is associated with a financial entity, 32 percent for on peak, which is associated with a physical entity, and 33 percent for off peak FTR products, which is associated with a financial entity.

In order to evaluate the ownership of prevailing flow and counter flow FTRs, the MMU categorized all participants owning FTRs 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. The MMU used available public information to categorize FTR owners.

Table 8-3 presents the 2009 to 2012 Long Term FTR Auction market concentration for cleared FTRs by organization type and FTR direction. The results show that financial entities own almost two thirds of prevailing flow FTRs and more than half of counter flow FTRs. Overall, financial entities own about 61 percent of all Long Term FTRs.

28 PJM filed proposed revisions to Attachment Q in Docket No. ER09-650-000.

Table 8-3 Long Term FTR Auction patterns of ownership by FTR direction: Planning periods 2009 to 2012

	FTR Direction		
Organization Type	Prevailing Flow	Counter Flow	All
Physical	36.7%	41.9%	39.2%
Financial	63.3%	58.1%	60.8%
Total	100.0%	100.0%	100.0%

Table 8-4 presents the Annual FTR Auction market concentration for cleared FTRs in the 2008 to 2009 planning period by organization type and FTR direction. The results show that physical entities own more than half of prevailing flow FTRs while financial entities own almost three quarters of counter flow FTRs. Overall, financial entities own about 54 percent of all Annual FTRs.

Table 8-4 Annual FTR Auction patterns of ownership by FTR direction: Planning period 2008 to 2009

	FTR Direction		
Organization Type	Prevailing Flow	Counter Flow	All
Physical	54.2%	28.5%	46.5%
Financial	45.8%	71.5%	53.5%
Total	100.0%	100.0%	100.0%

Table 8-5 presents the Monthly Balance of Planning Period FTR Auction market concentration for cleared FTRs in calendar year 2008 by organization type and FTR direction. The results show that financial entities own two thirds of prevailing flow FTRs and about three quarters of counter flow FTRs. Overall, financial entities own about 70 percent of all Monthly Balance of Planning Period FTRs.

Table 8-5 Monthly Balance of Planning Period FTR Auction patterns of ownership by FTR direction: January 2008 to December 2008

	FTR Direction		
Organization Type	Prevailing Flow	Counter Flow	All
Physical	33.3%	25.4%	29.6%
Financial	66.7%	74.6%	70.4%
Total	100.0%	100.0%	100.0%

Market Performance

Volume

Table 8-6 shows the 2009 to 2010 Long Term FTR Auction volume by trade type, FTR direction and period type.[29] The total volume was 803,911 MW for FTR buy bids and 15,757 MW for FTR sell offers in the 2009 to 2012 Long Term FTR Auction. The Long Term FTR Auction cleared 52,369 MW (6.5 percent) leaving 751,542 MW (93.5 percent) of uncleared FTR buy bids. There were 1,010 MW (6.4 percent) of cleared FTR sell offers leaving 14,747 MW (93.6 percent) of uncleared FTR sell offers.

Table 8-6 Long Term FTR Auction market volume: Planning periods 2009 to 2012

Trade Type	FTR Direction	Period Type	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
Buy bids	Counter Flow	Year 1	30,399	89,715	13,221	14.7%	76,494	85.3%
		Year 2	12,342	45,995	7,561	16.4%	38,434	83.6%
		Year 3	11,019	37,891	4,873	12.9%	33,018	87.1%
		Year All	16	106	17	15.9%	89	84.1%
		Total	53,776	173,707	25,672	14.8%	148,035	85.2%
	Prevailing Flow	Year 1	66,689	319,514	15,100	4.7%	304,414	95.3%
		Year 2	29,101	177,507	7,113	4.0%	170,394	96.0%
		Year 3	20,956	128,944	4,380	3.4%	124,564	96.6%
		Year All	220	4,239	104	2.5%	4,135	97.5%
		Total	116,966	630,204	26,697	4.2%	603,507	95.8%
	Total		170,742	803,911	52,369	6.5%	751,542	93.5%
Sell offers	Counter Flow	Year 1	2,037	3,499	169	4.8%	3,330	95.2%
		Year 2	839	1,997	214	10.7%	1,783	89.3%
		Year 3	856	1,469	122	8.3%	1,347	91.7%
		Year All	1	5	0	0.0%	5	100.0%
		Total	3,733	6,970	505	7.3%	6,464	92.7%
	Prevailing Flow	Year 1	1,849	4,486	270	6.0%	4,215	94.0%
		Year 2	1,346	2,596	123	4.7%	2,473	95.3%
		Year 3	1,027	1,706	112	6.5%	1,594	93.5%
		Year All	NA	NA	NA	NA	NA	NA
		Total	4,222	8,787	504	5.7%	8,283	94.3%
	Total		7,955	15,757	1,010	6.4%	14,747	93.6%

29 Calculated values shown in Section 8, "Financial Transmission and Auction Revenue Rights," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

Table 8-7 shows the Annual FTR Auction volume by trade type and FTR direction for the 2008 to 2009 planning period. The total volume was 2,181,273 MW for FTR buy bids and 83,453 MW for FTR sell offers for the 2008 to 2009 planning period. This is down from the total volume of 2,223,687 MW for FTR buy bids and 117,199 MW for FTR sell offers for the 2007 to 2008 planning period.

There were 204,349 MW (9.4 percent) of cleared FTR buy bids and 4,534 MW (5.4 percent) of cleared FTR sell offers for the 2008 to 2009 planning period. This is down from the total of 208,637 MW (9.4 percent) of cleared FTR buy bids and 6,495 MW (5.5 percent) of cleared FTR sell offers for the 2007 to 2008 planning period.

For the 2008 to 2009 planning period, there were 76,586 MW (27.3 percent) cleared out of 280,667 MW counter flow FTR buy bids and 127,763 MW (6.7 percent) cleared out of 1,900,606 MW prevailing flow FTR buy bids. During the 2008 to 2009 planning period, there were 1,522 MW (4.7 percent) cleared out of 32,596 MW counter flow FTR sell offers and 3,012 MW (5.9 percent) cleared out of 50,857 MW prevailing flow FTR offers.

Table 8-7 Annual FTR Auction market volume: Planning period 2008 to 2009

Trade Type	FTR Direction	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
Buy bids	Counter Flow	52,614	280,667	76,586	27.3%	204,081	72.7%
	Prevailing Flow	211,684	1,900,606	127,763	6.7%	1,772,843	93.3%
	Total	264,298	2,181,273	204,349	9.4%	1,976,924	90.6%
Self-scheduled bids	Counter Flow	378	3,990	3,990	100.0%	0	0.0%
	Prevailing Flow	10,410	68,861	68,861	100.0%	0	0.0%
	Total	10,788	72,851	72,851	100.0%	0	0.0%
Buy and self-scheduled bids	Counter Flow	52,992	284,657	80,576	28.3%	204,081	71.7%
	Prevailing Flow	222,094	1,969,467	196,624	10.0%	1,772,843	90.0%
	Total	275,086	2,254,124	277,200	12.3%	1,976,924	87.7%
Sell offers	Counter Flow	8,273	32,596	1,522	4.7%	31,074	95.3%
	Prevailing Flow	9,566	50,857	3,012	5.9%	47,845	94.1%
	Total	17,839	83,453	4,534	5.4%	78,919	94.6%

Table 8-8 shows that for the 2008 to 2009 planning period, eligible market participants converted 72,851 MW of ARRs out of a possible 112,011 MW into Annual FTRs. In comparison, during the 2007 to 2008 planning period, eligible market participants converted 71,360 MW of ARRs out of a possible 107,992 MW.

Table 8-8 Comparison of self scheduled FTRs: Planning periods 2007 to 2008 and 2008 to 2009

Planning Period	Self-Scheduled FTRs (MW)	Maximum Possible Self-Scheduled FTRs (MW)	Percent of ARRs Self-Scheduled as FTRs
2007/2008	71,360	107,992	66.1%
2008/2009	72,851	112,011	65.0%

Table 8-9 shows that there were 7,593,736 MW of FTR buy bids and 1,436,957 MW of FTR sell offers for all bidding periods in the Monthly Balance of Planning Period FTR Auctions for the 2008 to 2009 planning period through December 31, 2008. The monthly auctions cleared 545,189 MW (7.2 percent) leaving 7,048,547 MW (92.8 percent) of uncleared FTR buy bids. There were 183,322 MW (12.8 percent) of cleared FTR sell offers leaving 1,253,634 MW (87.2 percent) of uncleared FTR sell offers.

The Monthly Balance of Planning Period FTR Auctions for the full 12-month 2007 to 2008 planning period had a total demand of 11,109,209 MW for FTR buy bids and 2,464,879 MW for FTR sell offers. The monthly auctions cleared 827,980 MW (7.5 percent) of FTR buy bids and 218,508 MW (8.9 percent) of FTR sell offers.

Table 8-9 Monthly Balance of Planning Period FTR Auction market volume: January 2008 to December 2008

Monthly Auction	Trade Type	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
Jan-08	Buy bids	121,150	655,581	43,616	6.7%	611,965	93.3%
	Sell offers	33,325	153,940	16,239	10.5%	137,700	89.5%
Feb-08	Buy bids	132,654	676,847	48,951	7.2%	627,896	92.8%
	Sell offers	17,347	93,099	11,663	12.5%	81,436	87.5%
Mar-08	Buy bids	130,371	590,524	47,641	8.1%	542,883	91.9%
	Sell offers	36,787	153,283	15,700	10.2%	137,583	89.8%
Apr-08	Buy bids	105,398	427,105	46,282	10.8%	380,822	89.2%
	Sell offers	23,496	101,055	11,477	11.4%	89,577	88.6%
May-08	Buy bids	69,834	331,327	30,660	9.3%	300,667	90.7%
	Sell offers	12,751	51,322	7,823	15.2%	43,499	84.8%
Jun-08	Buy bids	258,681	1,578,046	104,786	6.6%	1,473,260	93.4%
	Sell offers	45,414	237,585	37,798	15.9%	199,788	84.1%
Jul-08	Buy bids	278,209	1,211,784	85,641	7.1%	1,126,143	92.9%
	Sell offers	60,834	243,169	31,798	13.1%	211,371	86.9%
Aug-08	Buy bids	222,740	1,224,054	76,642	6.3%	1,147,412	93.7%
	Sell offers	74,462	262,360	36,615	14.0%	225,744	86.0%
Sep-08	Buy bids	205,073	1,127,274	89,543	7.9%	1,037,731	92.1%
	Sell offers	45,594	202,025	24,642	12.2%	177,382	87.8%
Oct-08	Buy bids	182,669	965,756	69,103	7.2%	896,653	92.8%
	Sell offers	39,073	162,790	16,335	10.0%	146,455	90.0%
Nov-08	Buy bids	160,000	738,336	57,286	7.8%	681,051	92.2%
	Sell offers	32,106	130,895	11,579	8.8%	119,316	91.2%
Dec-08	Buy bids	156,711	748,485	62,188	8.3%	686,298	91.7%
	Sell offers	47,312	198,133	24,555	12.4%	173,578	87.6%
2007/2008	Buy bids	2,015,915	11,109,209	827,980	7.5%	10,281,228	92.5%
	Sell offers	479,109	2,464,879	218,508	8.9%	2,246,371	91.1%
2008/2009*	Buy bids	1,464,083	7,593,736	545,189	7.2%	7,048,547	92.8%
	Sell offers	344,795	1,436,957	183,322	12.8%	1,253,634	87.2%

* Shows seven months ended 31-Dec-2008

Table 8-10 shows the bid and cleared volume for FTR buy bids in the Monthly Balance of Planning Period FTR Auctions by bidding period for January 2008 through December 2008.

Table 8-10 Monthly Balance of Planning Period FTR Auction buy-bid bid and cleared volume (MW per period): January 2008 to December 2008

Monthly Auction	MW Type	Current Month	Second Month	Third Month	Q1	Q2	Q3	Q4	Total
Jan-08	Bid	301,410	126,592	106,864				120,716	655,581
	Cleared	25,820	7,271	5,309				5,217	43,616
Feb-08	Bid	335,163	116,029	107,688				117,967	676,847
	Cleared	31,353	6,255	7,050				4,294	48,951
Mar-08	Bid	305,542	119,701	113,947				51,333	590,524
	Cleared	33,164	6,541	6,893				1,044	47,641
Apr-08	Bid	309,583	117,522						427,105
	Cleared	37,759	8,524						46,282
May-08	Bid	331,327							331,327
	Cleared	30,660							30,660
Jun-08	Bid	423,967	189,183	188,548	137,116	221,329	209,937	207,965	1,578,046
	Cleared	40,813	11,687	11,171	7,730	14,272	9,977	9,137	104,786
Jul-08	Bid	357,395	202,677	81,392		193,734	187,958	188,629	1,211,784
	Cleared	40,994	13,117	5,814		9,013	8,686	8,016	85,641
Aug-08	Bid	379,607	154,227	141,115		175,934	193,429	179,743	1,224,054
	Cleared	40,040	10,660	6,225		5,187	8,166	6,364	76,642
Sep-08	Bid	342,026	164,862	146,930		114,635	183,454	175,368	1,127,274
	Cleared	44,418	9,295	8,773		4,384	12,309	10,364	89,543
Oct-08	Bid	343,978	149,085	135,665			169,046	167,982	965,756
	Cleared	46,209	7,040	4,194			5,123	6,538	69,103
Nov-08	Bid	304,367	97,067	86,861			126,107	123,935	738,336
	Cleared	36,712	4,257	3,232			5,311	7,773	57,286
Dec-08	Bid	287,435	123,385	115,498			79,524	142,643	748,486
	Cleared	32,875	8,251	7,125			3,918	10,019	62,188

Table 8-11 shows the secondary bilateral FTR market volume by hedge type and class type for the 2007 to 2008 and the 2008 to 2009 planning periods. There were 1,665 MW of total bilateral FTR activity for the 2008 to 2009 planning period while there were 2,122 MW during the 2007 to 2008 planning period. There were no option FTRs traded through the PJM secondary bilateral FTR market for the 2008 to 2009 planning period.

Table 8-11 Secondary bilateral FTR market volume: Planning periods 2007 to 2008 and 2008 to 2009[30]

Planning Period	Hedge Type	Class Type	Secondary (MW)
2007/2008	Obligation	24-Hour	57
		On Peak	1,239
		Off Peak	216
		Total	1,512
	Option	24-Hour	0
		On Peak	446
		Off Peak	164
		Total	610
2008/2009	Obligation	24-Hour	532
		On Peak	1,133
		Off Peak	0
		Total	1,665

30 The 2008 to 2009 planning period covers the 2008 to 2009 Annual FTR Auction and the Monthly Balance of Planning Period FTR Auctions through December 31, 2008.

Price

Table 8-12 shows the cleared, weighted-average prices by trade type, FTR direction, period type and class type for the 2009 to 2012 Long Term FTR Auction. Only FTR obligation products are available in Long Term FTR Auctions. In this auction, weighted-average, buy-bid FTR prices were $0.16 per MWh while weighted-average sell offer FTR prices were $0.29 per MWh.

Table 8-12 Long Term FTR Auction weighted-average cleared prices (Dollars per MWh): Planning periods 2009 to 2012

			Class Type			
Trade Type	FTR Direction	Period Type	24-Hour	On Peak	Off Peak	All
Buy bids	Counter Flow	Year 1	($1.16)	($0.64)	($0.66)	($0.75)
		Year 2	($0.88)	($0.71)	($0.99)	($0.84)
		Year 3	($0.19)	($0.77)	($0.83)	($0.75)
		Year All	($7.72)	($5.09)	($3.95)	($5.72)
		Total	($1.03)	($0.69)	($0.79)	($0.78)
	Prevailing Flow	Year 1	$1.63	$0.70	$0.72	$0.86
		Year 2	$1.61	$0.88	$1.27	$1.09
		Year 3	$0.78	$0.82	$1.08	$0.91
		Year All	$9.97	$0.11	$0.22	$8.71
		Total	$2.58	$0.77	$0.92	$1.08
	Total		$0.76	$0.10	$0.01	$0.16
Sell offers	Counter Flow	Year 1	NA	($0.25)	($0.14)	($0.21)
		Year 2	NA	($0.12)	($0.21)	($0.17)
		Year 3	NA	($1.21)	($1.01)	($1.08)
		Year All	NA	NA	NA	NA
		Total	NA	($0.37)	($0.44)	($0.41)
	Prevailing Flow	Year 1	NA	$0.87	$1.13	$0.99
		Year 2	NA	$0.68	$0.49	$0.62
		Year 3	NA	$1.73	$0.90	$1.48
		Year All	NA	NA	NA	NA
		Total	NA	$1.04	$0.96	$1.01
	Total		NA	$0.40	$0.16	$0.29

The 2009 to 2012 Long Term FTR Auction price duration curve for cleared buy bids in Figure 8-1 shows that 90.7 percent of Long Term FTRs were purchased for less than $1 per MWh, 94.5 percent for less than $2 per MWh and 96.1 percent for less than $3 per MWh. Negative prices occur because some FTRs are bid with negative prices and some winning FTR bidders are paid to take FTRs.

Figure 8-1 Long Term FTR auction clearing price duration curve: Planning periods 2009 to 2012

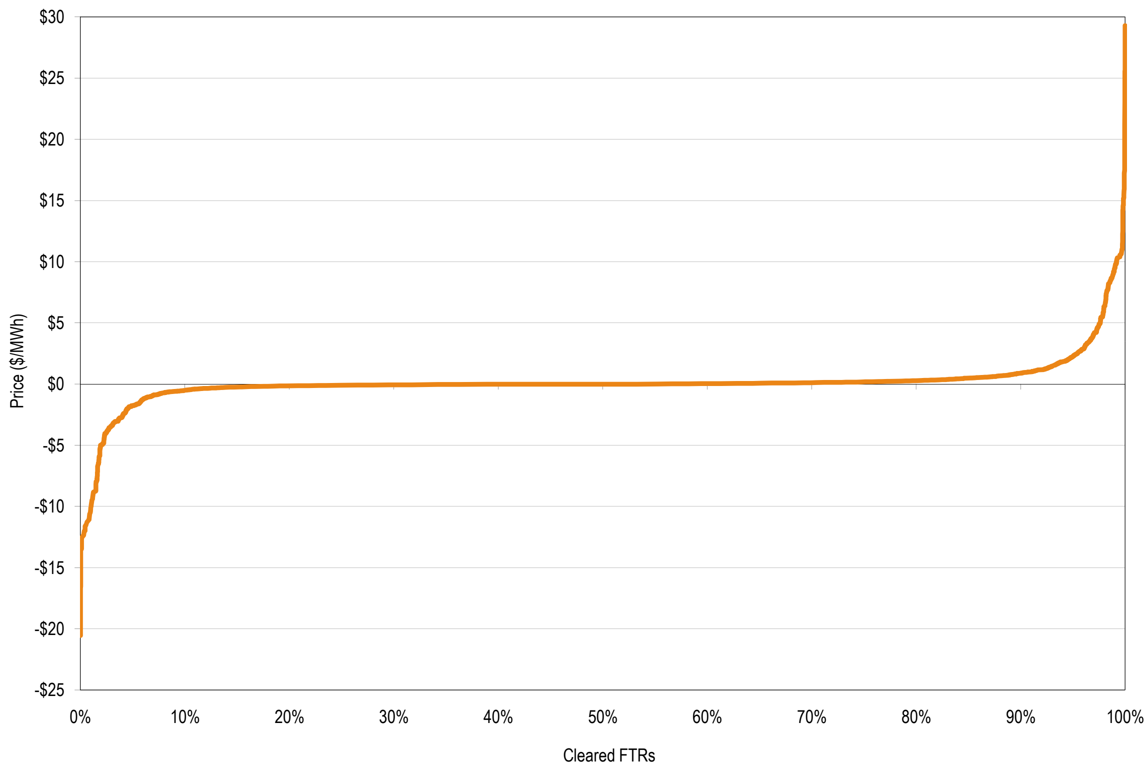


Table 8-13 shows the cleared, weighted-average prices by trade type, FTR direction and class type for Annual FTRs during the 2008 to 2009 planning period. For the 2008 to 2009 planning period, weighted-average, buy-bid FTR obligation prices were $0.69 per MWh while weighted-average, buy-bid FTR option prices were $0.24 per MWh. Comparable weighted-average prices for the 2007 to 2008 planning period were $0.47 per MWh for buy-bid FTR obligations and $0.37 per MWh for buy-bid FTR options.

During the 2008 to 2009 planning period, weighted-average sell offer FTR obligation prices were $0.86 per MWh while weighted-average sell offer FTR option prices were $0.84 per MWh. Comparable weighted-average prices for the 2007 to 2008 planning period were -$0.07 per MWh for sell offer FTR obligations and $0.94 per MWh for sell offer FTR options.

On average during the 2008 to 2009 planning period in the Annual FTR Auction, self scheduled FTRs were priced $2.14 per MWh higher than buy-bid obligation FTRs. They were also priced $0.89 per MWh higher than the cleared, weighted-average price of self scheduled FTRs during the 2007 to 2008 planning period.

During the 2008 to 2009 planning period, weighted-average, buy-bid FTR obligation prices were -$1.06 per MWh for counter flow FTRs and $1.75 per MWh for prevailing flow FTRs. Weighted-average sell offer FTR obligation prices were -$0.95 per MWh for counter flow FTRs and $1.64 per MWh for prevailing flow FTRs during the 2008 to 2009 planning period. On average during the 2008 to 2009 planning period in the Annual FTR Auction, self scheduled counter flow FTRs were priced $0.53 per MWh higher than buy-bid counter flow obligation FTRs and self scheduled prevailing FTRs were priced $1.28 per MWh higher than buy-bid prevailing flow obligation FTRs.

Table 8-13 Annual FTR Auction weighted-average cleared prices by FTR direction (Dollars per MWh): Planning period 2008 to 2009

			Class Type			
Trade Type	Hedge Type	FTR Direction	24-Hour	On Peak	Off Peak	All
Buy bids	Obligations	Counter Flow	($0.84)	($1.25)	($0.96)	($1.06)
		Prevailing Flow	$2.93	$1.63	$1.20	$1.75
		Total	$1.96	$0.55	$0.26	$0.69
	Options	Counter Flow	$0.00	$0.00	$0.00	$0.00
		Prevailing Flow	$0.37	$0.46	$0.19	$0.35
		Total	$0.06	$0.39	$0.15	$0.24
Self-scheduled bids	Obligations	Counter Flow	($0.53)	NA	NA	($0.53)
		Prevailing Flow	$3.03	NA	NA	$3.03
		Total	$2.83	NA	NA	$2.83
Buy and self-scheduled bids	Obligations	Counter Flow	($0.70)	($1.25)	($0.96)	($1.01)
		Prevailing Flow	$3.01	$1.63	$1.20	$2.42
		Total	$2.66	$0.55	$0.26	$1.59
Sell offers	Obligations	Counter Flow	($1.01)	($1.43)	($0.66)	($0.95)
		Prevailing Flow	$1.38	$1.82	$1.77	$1.64
		Total	$1.22	$0.40	$0.88	$0.86
	Options	Counter Flow	NA	NA	NA	NA
		Prevailing Flow	NA	$0.70	$3.92	$0.84
		Total	NA	$0.70	$3.92	$0.84

The 2008 to 2009 planning period price duration curve for cleared buy bids in Figure 8-2 shows that 83.5 percent of Annual FTRs were purchased for less than $1 per MWh, 88.8 percent for less than $2 per MWh and 91.5 percent for less than $3 per MWh. Negative prices occur because some FTRs are bid with negative prices and some winning FTR bidders are paid to take FTRs. The 2008 to 2009 planning period FTR obligation price duration curve for cleared buy bids in Figure 8-2 shows that 82.3 percent of annual FTR obligations were purchased for less than $1 per MWh, 87.9 percent for less than $2 per MWh and 90.8 percent for less than $3 per MWh. The 2008 to 2009 planning period FTR option price duration curve for cleared buy bids in Figure 8-2 shows that 94.8 percent of annual FTR options were purchased for less than $1 per MWh, 97.4 percent for less than $2 per MWh and 98.7 percent for less than $3 per MWh.

Figure 8-2 Annual FTR auction clearing price duration curves: Planning period 2008 to 2009

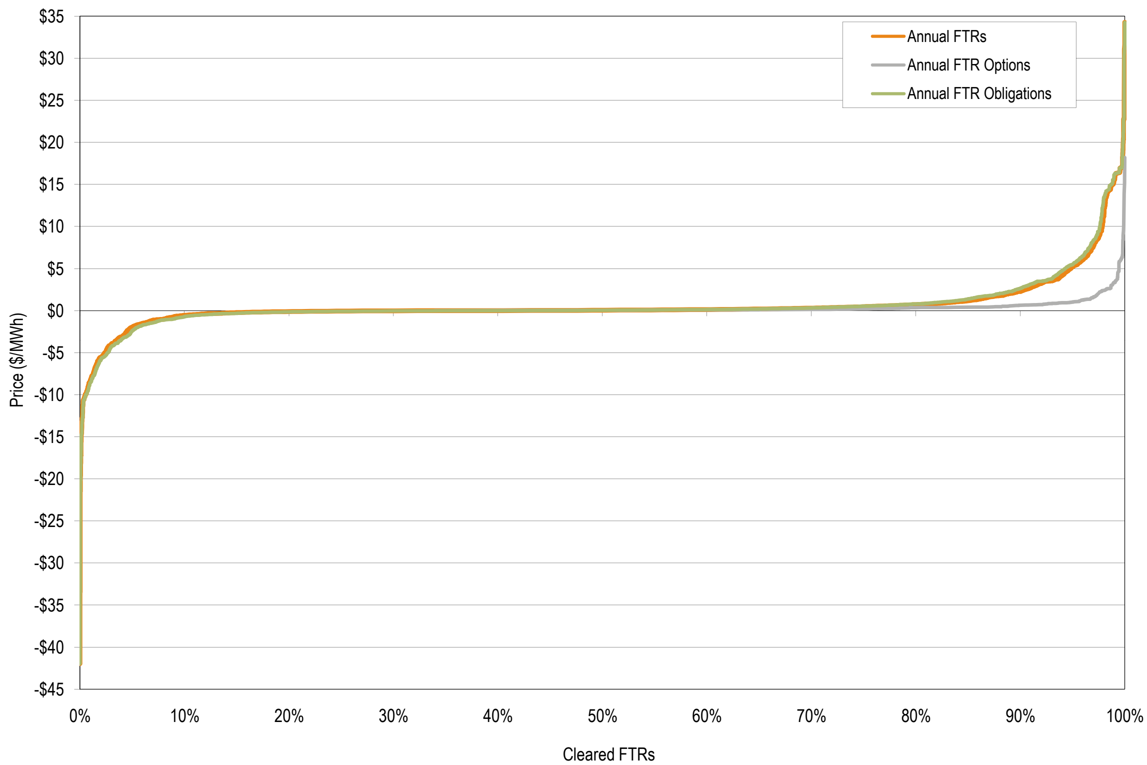


Table 8-14 shows the weighted-average cleared buy-bid price in the Monthly Balance of Planning Period FTR Auctions by bidding period for January 2008 through December 2008. For example, for the June 2008 Monthly Balance of Planning Period FTR Auction, the current month column is June, the second month column is July and the third month column is August. Quarters 1 through 4 are represented in the Q1, Q2, Q3 and Q4 columns. The total column represents all of the activity within the June 2008 Monthly Balance of Planning Period FTR Auction.

The cleared, weighted-average price paid in the Monthly Balance of Planning Period FTR Auctions during the first seven months of the 2008 to 2009 planning period was $0.35 per MWh, compared with $0.21 per MWh for the full 12-month 2007 to 2008 planning period.

Table 8-14 Monthly Balance of Planning Period FTR Auction cleared, weighted-average, buy-bid price per period (Dollars per MWh): January 2008 to December 2008

Monthly Auction	Current Month	Second Month	Third Month	Q1	Q2	Q3	Q4	Total
Jan-08	$0.51	$1.24	$0.04				$0.45	$0.54
Feb-08	$0.36	$0.34	$0.17				$0.50	$0.37
Mar-08	$0.22	$0.59	$0.42				$0.91	$0.35
Apr-08	$0.15	$0.20						$0.16
May-08	($0.03)							($0.03)
Jun-08	$0.16	$0.22	$0.03	$0.85	$0.46	$0.74	$0.55	$0.46
Jul-08	$0.24	$0.55	($0.11)		$0.62	$0.46	$0.63	$0.44
Aug-08	$0.24	($0.08)	$0.51		$0.96	$0.94	$0.69	$0.55
Sep-08	$0.26	$0.46	$0.24		$0.18	$0.48	$0.10	$0.28
Oct-08	$0.15	$0.11	$0.11			$0.03	$0.38	$0.17
Nov-08	$0.11	$0.53	$0.23			$0.09	$0.16	$0.14
Dec-08	$0.21	$0.48	$0.53			($0.11)	$0.16	$0.20

Revenue

Long Term FTR Auction Revenue

Table 8-15 shows Long Term FTR Auction revenue data by trade type, FTR direction, period type, and class type. The 2009 to 2012 Long Term FTR Auction netted $38.93 million in revenue, with buyers paying $40.21 million and sellers receiving $1.28 million.

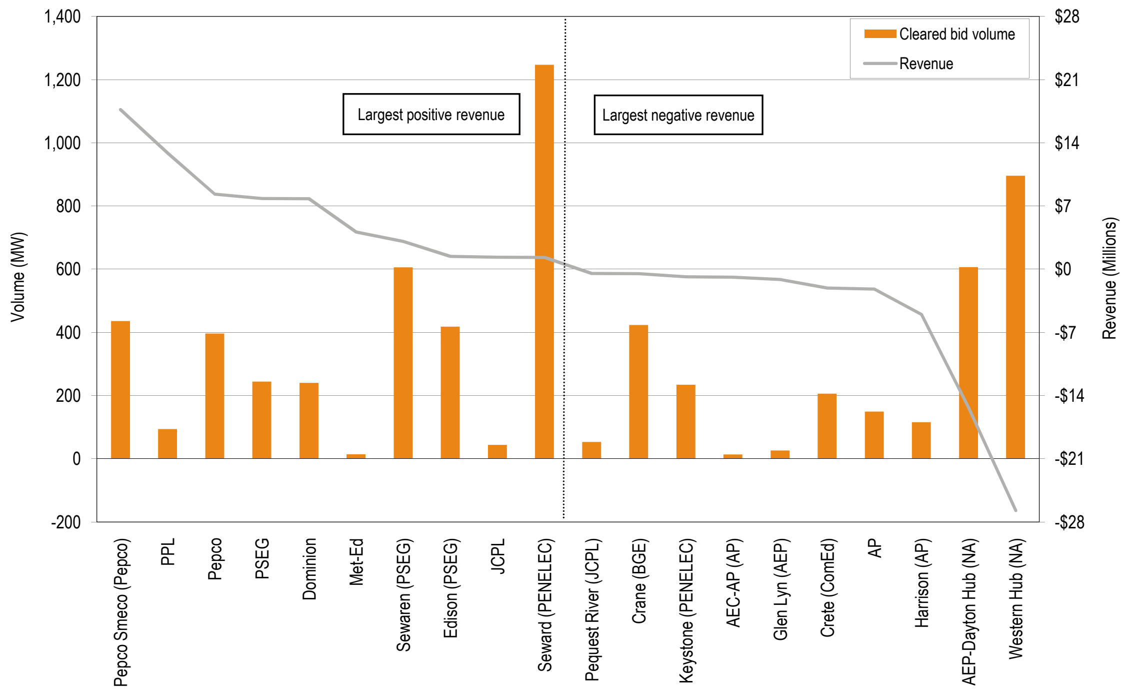
For the 2009 to 2012 Long Term FTR Auction, the counter flow FTRs netted -$93.96 million in revenue, with buyers receiving $94.86 million and sellers paying $0.90 million, and the prevailing flow FTRs netted $132.90 million in revenue, with buyers paying $135.08 million and sellers receiving $2.18 million.

Table 8-15 Long Term FTR Auction revenue: Planning periods 2009 to 2012

			Class Type			
Trade Type	FTR Direction	Period Type	24-Hour	On Peak	Off Peak	All
Buy bids	Counter Flow	Year 1	($13,841,184)	($16,235,257)	($17,429,755)	($47,506,196)
		Year 2	($3,371,015)	($12,102,496)	($13,645,824)	($29,119,334)
		Year 3	($366,210)	($7,871,455)	($8,390,435)	($16,628,101)
		Year All	($873,245)	($313,376)	($420,280)	($1,606,902)
		Total	($18,451,655)	($36,522,584)	($39,886,293)	($94,860,532)
	Prevailing Flow	Year 1	$19,418,180	$23,467,067	$18,607,416	$61,492,663
		Year 2	$4,569,526	$15,361,162	$15,148,432	$35,079,120
		Year 3	$672,352	$9,513,622	$7,274,461	$17,460,435
		Year All	$20,996,081	$21,543	$25,536	$21,043,160
		Total	$45,656,139	$48,363,394	$41,055,845	$135,075,378
	Total		$27,204,484	$11,840,810	$1,169,552	$40,214,846
Sell offers	Counter Flow	Year 1	NA	($114,252)	($36,943)	($151,195)
		Year 2	NA	($52,649)	($107,243)	($159,892)
		Year 3	NA	($232,483)	($356,536)	($589,020)
		Year All	NA	NA	NA	NA
		Total	NA	($399,384)	($500,723)	($900,107)
	Prevailing Flow	Year 1	NA	$549,418	$608,750	$1,158,168
		Year 2	NA	$238,267	$85,293	$323,560
		Year 3	NA	$569,493	$132,334	$701,827
		Year All	NA	NA	NA	NA
		Total	NA	$1,357,178	$826,377	$2,183,555
	Total		NA	$957,794	$325,654	$1,283,448

Figure 8-3 summarizes total revenue associated with all FTRs, regardless of source, to the FTR sinks that produced the largest positive and negative revenue from the 2009 to 2012 Long Term FTR Auction.[31] The top 10 positive revenue producing FTR sinks accounted for $65.8 million of the total revenue of $38.93 million paid in the auction. They also comprised 7.3 percent of all FTRs bought in the auction. The sinks with the highest positive auction revenue are all control zones or large aggregates. The top 10 negative revenue producing FTR sinks accounted for -$55.2 million of revenue and constituted 5.3 percent of all FTRs bought in the auction.

Figure 8-3 Ten largest positive and negative revenue producing FTR sinks purchased in the Long Term FTR Auction: Planning periods 2009 to 2012[32]

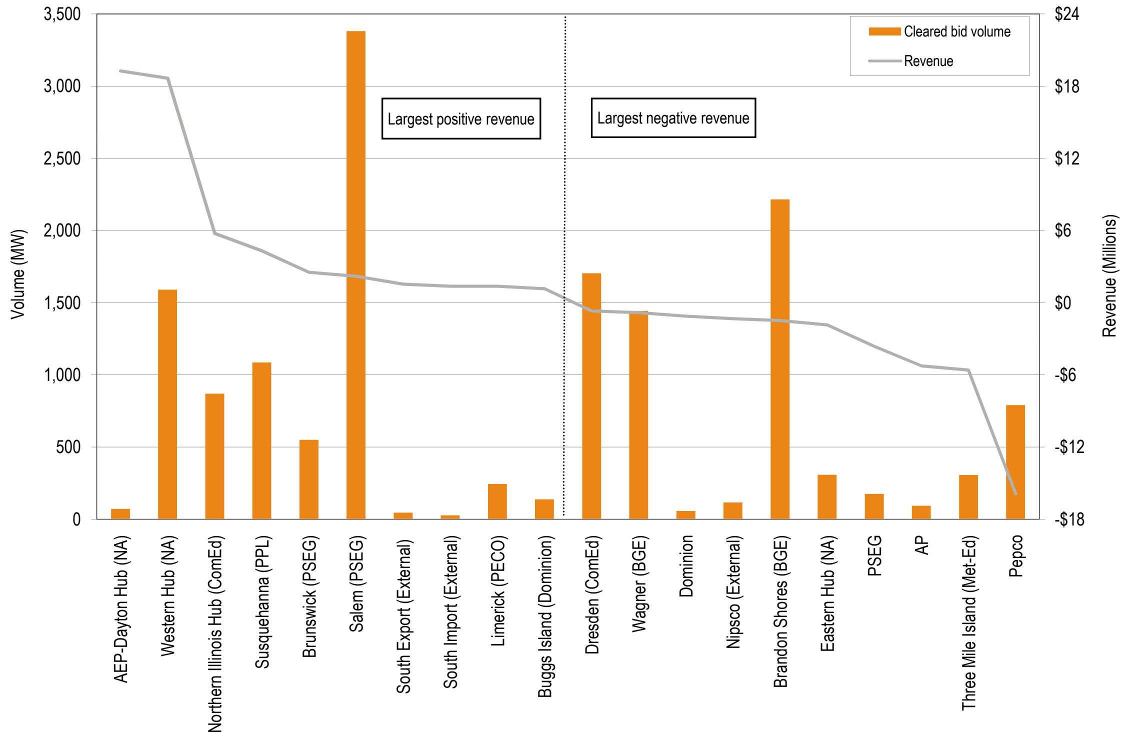


31 As some FTRs are bid with negative prices, some winning FTR bidders are paid to take FTRs. These are counter flow FTRs. These payments reduce net auction revenue. Therefore, the sum of the highest revenue producing FTRs can exceed net auction revenue.

32 For Figure 8-3 through Figure 8-10, each FTR sink and source that is not a control zone has its corresponding control zone listed in parentheses after its name. Most FTR sink and source control zone identifications for hubs and interface pricing points are listed as NA because they cannot be assigned to a specific control zone.

Figure 8-4 summarizes total revenue associated with all FTRs, regardless of sink, from the FTR sources that produced the largest positive and negative revenue from the 2009 to 2012 Long Term FTR Auction. The top 10 positive revenue producing FTR sources accounted for $58.2 million of the total revenue of $38.93 million paid in the auction. They also comprised 15.6 percent of all FTRs bought in the auction. The top 10 negative revenue producing FTR sources accounted for -$37.7 million of revenue and constituted 14.0 percent of all FTRs bought in the auction.

Figure 8-4 Ten largest positive and negative revenue producing FTR sources purchased in the Long Term FTR Auction: Planning periods 2009 to 2012



Annual FTR Auction Revenue

Table 8-16 shows Annual FTR Auction revenue data by trade type, FTR direction and class type. For the 2008 to 2009 planning period, the Annual FTR Auction netted $2,422.55 million in revenue, with buyers paying $2,442.57 million and sellers receiving $20.02 million. For the 2007 to 2008 planning period, the Annual FTR Auction netted $1,698.03 million in revenue, with buyers paying $1,698.28 million and sellers receiving $0.25 million.

For the 2008 to 2009 planning period, the counter flow FTRs in the Annual FTR Auction netted -$367.20 million in revenue, with buyers receiving $373.80 million and sellers paying $6.60 million, and the prevailing flow FTRs in the Annual FTR Auction netted $2,789.75 million in revenue, with buyers paying $2,816.37 million and sellers receiving $26.62 million.

Table 8-16 Annual FTR Auction revenue by FTR direction: Planning period 2008 to 2009

		Class Type			
Trade Type	FTR Direction	24-Hour	On Peak	Off Peak	All
Buy bids	Counter Flow	($35,510,737)	($166,562,876)	($153,077,258)	($355,150,871)
	Prevailing Flow	$354,788,437	$378,171,307	$255,569,002	$988,528,746
	Total	$319,277,700	$211,608,431	$102,491,744	$633,377,875
Self-scheduled bids	Counter Flow	($18,648,667)	NA	NA	($18,648,667)
	Prevailing Flow	$1,827,844,677	NA	NA	$1,827,844,677
	Total	$1,809,196,009	NA	NA	$1,809,196,009
Buy and self-scheduled bids	Counter Flow	($54,159,404)	($166,562,876)	($153,077,258)	($373,799,538)
	Prevailing Flow	$2,182,633,114	$378,171,307	$255,569,002	$2,816,373,423
	Total	$2,128,473,709	$211,608,431	$102,491,744	$2,442,573,885
Sell offers	Counter Flow	($435,226)	($3,456,795)	($2,710,863)	($6,602,884)
	Prevailing Flow	$8,189,721	$5,849,792	$12,578,975	$26,618,489
	Total	$7,754,496	$2,392,998	$9,868,112	$20,015,605

Figure 8-5 summarizes total revenue associated with all FTRs, regardless of source, to the FTR sinks that produced the largest positive and negative revenue from the Annual FTR Auction for the 2008 to 2009 planning period. The top 10 positive revenue producing FTR sinks accounted for $2,059.2 million (85.0 percent) of the total revenue of $2,422.55 million paid in the auction. They also comprised 28.5 percent of all FTRs bought in the auction. The sinks with the highest positive auction revenue are all control zones or large aggregates. The top 10 negative revenue producing FTR sinks accounted for -$70.3 million of revenue and constituted 2.5 percent of all FTRs bought in the auction.

Figure 8-5 Ten largest positive and negative revenue producing FTR sinks purchased in the Annual FTR Auction: Planning period 2008 to 2009

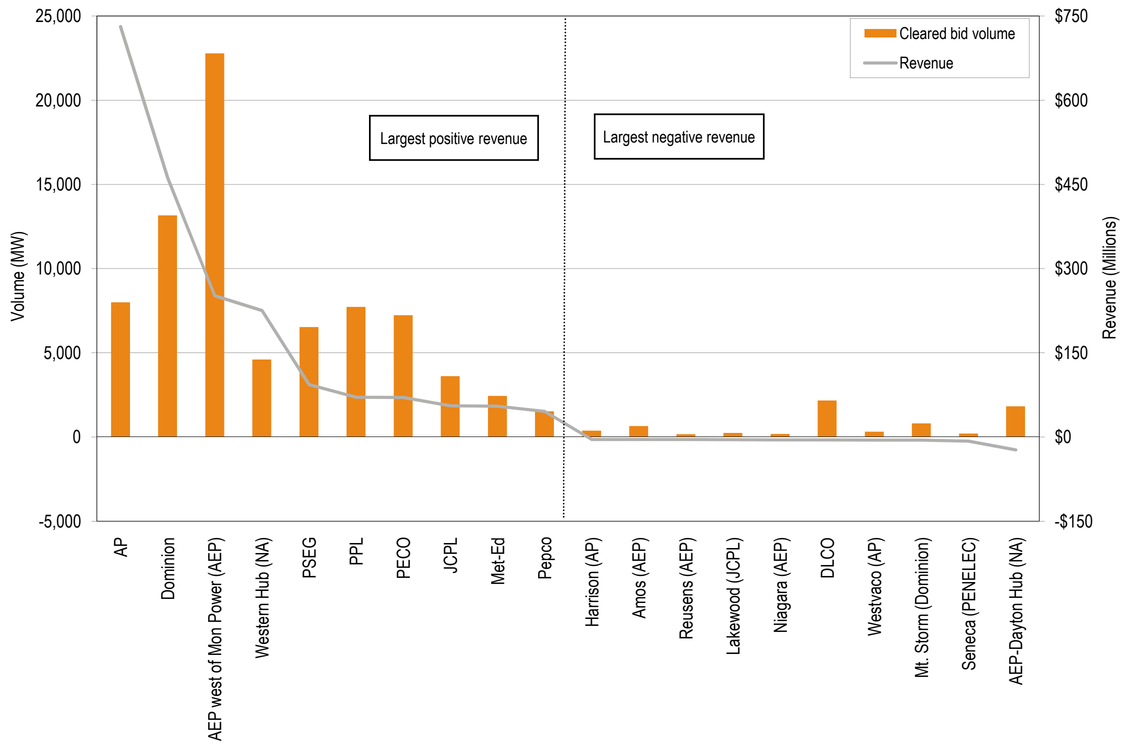
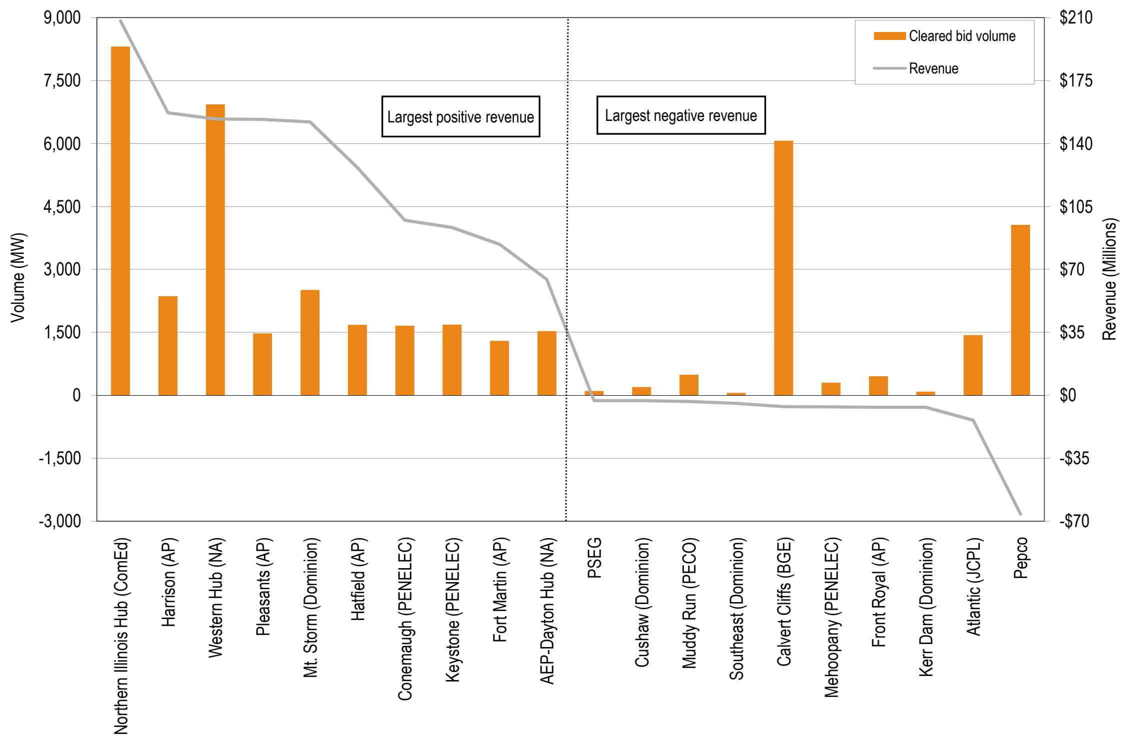


Figure 8-6 summarizes total revenue associated with all FTRs, regardless of sink, from the FTR sources that produced the largest positive and negative revenue from the Annual FTR Auction for the 2008 to 2009 planning period. The top 10 positive revenue producing FTR sources accounted for $1,290.2 million (53.3 percent) of the total revenue of $2,422.55 million paid in the auction. They also comprised 10.8 percent of all FTRs bought in the auction. The top 10 negative revenue producing FTR sources accounted for -$119.6 million of revenue and constituted 4.9 percent of all FTRs bought in the auction.

Figure 8-6 Ten largest positive and negative revenue producing FTR sources purchased in the Annual FTR Auction: Planning period 2008 to 2009



Monthly Balance of Planning Period FTR Auction Revenue

Table 8-17 shows Monthly Balance of Planning Period FTR Auction revenue data by trade type and class type. For the 2008 to 2009 planning period through December 31, 2008, the Monthly Balance of Planning Period FTR Auctions netted $62.2 million in revenue, with buyers paying $114.2 million and sellers receiving $52.0 million. For the 2007 to 2008 planning period, the Monthly Balance of Planning Period FTR Auctions netted $38.1 million in revenue, with buyers paying $89.7 million and sellers receiving $51.6 million.

Table 8-17 Monthly Balance of Planning Period FTR Auction revenue: January 2008 to December 2008

		Class Type			
Monthly Auction	Trade Type	24-Hour	On Peak	Off Peak	All
Jan-08	Buy bids	$1,056,855	$5,776,459	$3,979,264	$10,812,578
	Sell offers	$1,189,479	$3,567,666	$3,398,388	$8,155,532
Feb-08	Buy bids	$3,030,739	$3,873,706	$917,766	$7,822,210
	Sell offers	$1,069,325	$3,064,331	$978,938	$5,112,594
Mar-08	Buy bids	$2,925,839	$2,978,762	$548,680	$6,453,282
	Sell offers	$1,630,066	$2,032,643	$705,639	$4,368,348
Apr-08	Buy bids	$222,404	$1,699,081	$783,372	$2,704,857
	Sell offers	$401,052	$428,663	$218,783	$1,048,499
May-08	Buy bids	($1,352,053)	$657,727	$371,613	($322,712)
	Sell offers	$194,156	($493,147)	($762,509)	($1,061,499)
Jun-08	Buy bids	$18,533,708	$11,893,029	$2,324,087	$32,750,824
	Sell offers	$2,442,002	$11,909,347	$4,877,680	$19,229,028
Jul-08	Buy bids	$9,986,296	$8,245,240	$5,558,650	$23,790,186
	Sell offers	$852,227	$3,269,397	$3,406,768	$7,528,392
Aug-08	Buy bids	$757,259	$14,946,178	$8,892,488	$24,595,925
	Sell offers	$1,776,246	$5,848,899	$1,692,072	$9,317,216
Sep-08	Buy bids	($4,042,833)	$10,865,411	$8,499,440	$15,322,018
	Sell offers	$2,271,207	$3,028,611	$1,256,227	$6,556,044
Oct-08	Buy bids	$1,465,156	$3,344,823	$1,320,191	$6,130,170
	Sell offers	$1,794,603	$775,277	($166,592)	$2,403,289
Nov-08	Buy bids	($7,221,561)	$5,666,678	$6,118,436	$4,563,552
	Sell offers	$66,549	$1,058,174	$742,953	$1,867,675
Dec-08	Buy bids	($1,932,730)	$4,432,711	$4,514,107	$7,014,088
	Sell offers	$83,740	$2,391,833	$2,569,387	$5,044,960
2007/2008	Buy bids	$19,826,620	$51,439,514	$18,442,612	$89,708,747
	Sell offers	$19,149,340	$26,015,184	$6,443,352	$51,607,876
2008/2009*	Buy bids	$17,545,294	$59,394,071	$37,227,398	$114,166,763
	Sell offers	$9,286,572	$28,281,538	$14,378,494	$51,946,605

* Shows seven months ended 31-Dec-2008

Figure 8-7 summarizes total revenue associated with all FTRs, regardless of source, to the FTR sinks that produced the largest positive and negative revenue in the Monthly Balance of Planning Period FTR Auctions during the first seven months of the 2008 to 2009 planning period. The top 10 positive revenue producing FTR sinks accounted for $130.8 million of revenue and 8.0 percent of all FTRs bought in the Monthly Balance of Planning Period FTR Auctions. In the Monthly Balance of Planning Period FTR Auctions during the first seven months of the 2008 to 2009 planning period, there were 1,027 MW cleared bids for FTRs sunk at the new Neptune 230 kV line which generated $2.5 million of revenue. In the Monthly Balance of Planning Period FTR Auctions during the 2007 to 2008 planning period, there were 6,446 MW cleared bids for FTRs sunk into the new Neptune 230 kV line which generated $7.1 million of revenue. The top 10 negative revenue producing FTR sinks accounted for -$80.8 million of revenue and constituted 9.0 percent of all FTRs bought in the auctions. The net market volume sunk into the PECO Control Zone was negative since the total cleared volume of the monthly FTR buy bids sunk into PECO was less than the total cleared volume of the monthly FTR sell offers sunk into PECO.

Figure 8-7 Ten largest positive and negative revenue producing FTR sinks purchased in the Monthly Balance of Planning Period FTR Auctions: Planning period 2008 to 2009 through December 31, 2008

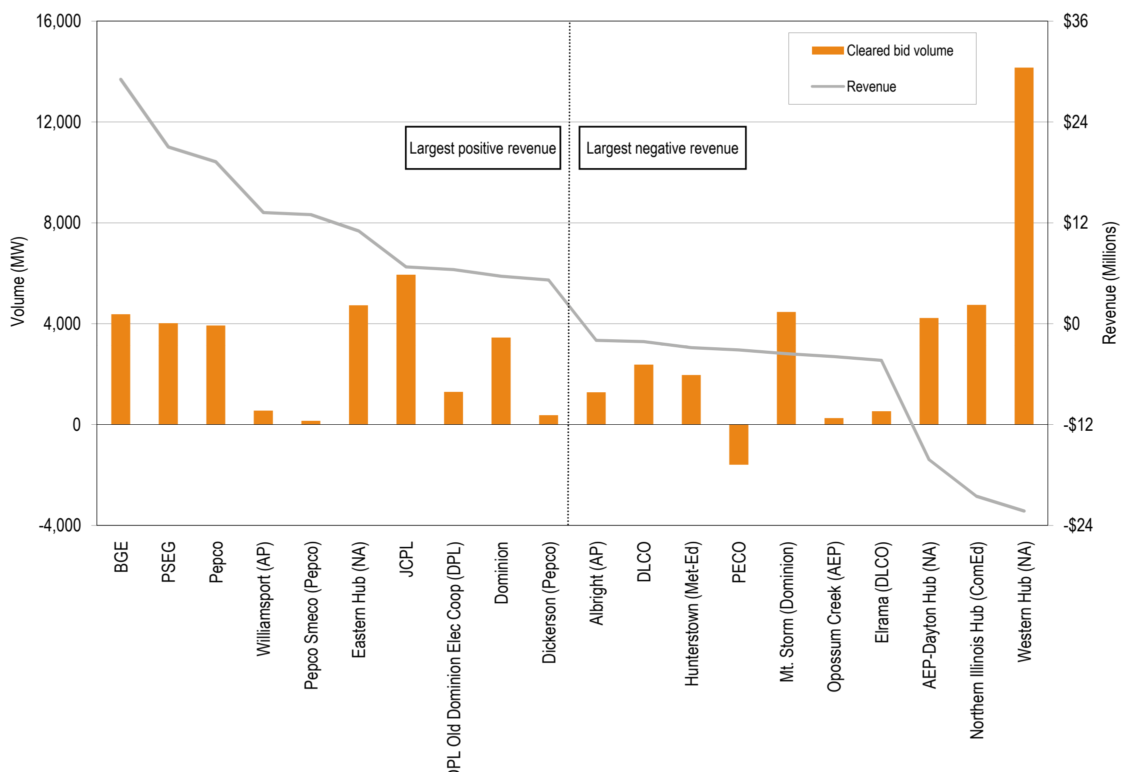
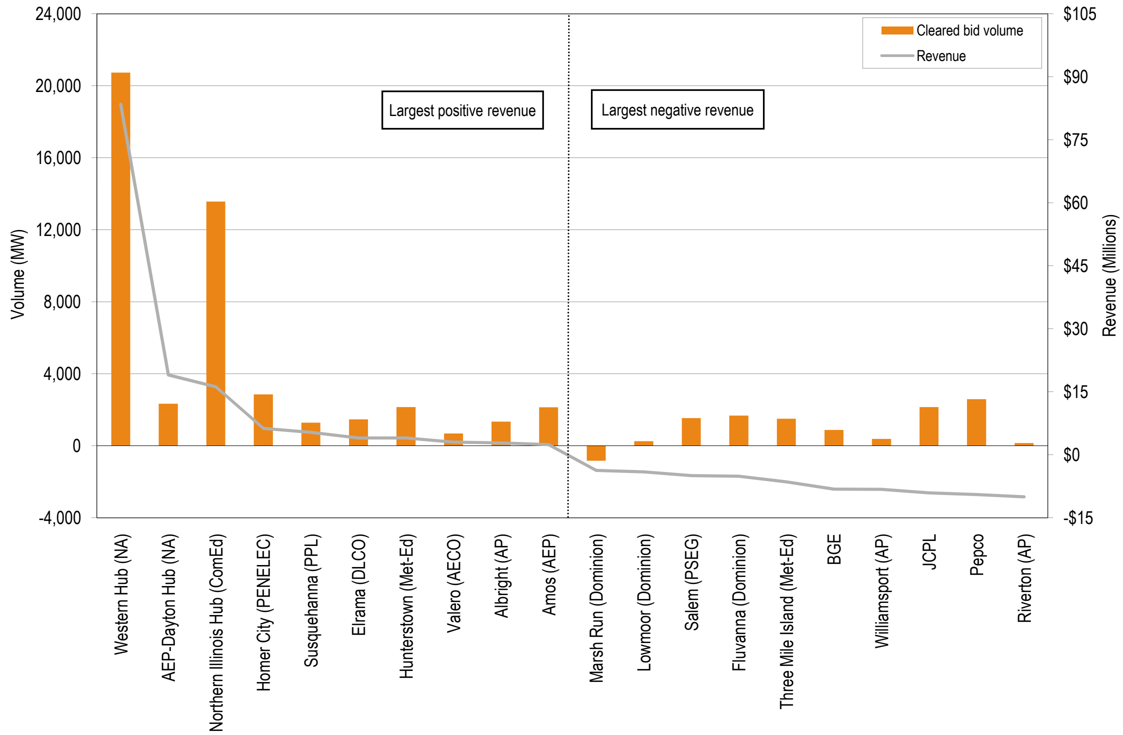


Figure 8-8 summarizes total revenue associated with all FTRs, regardless of sink, from the FTR sources that produced the largest positive and negative revenue from the Monthly Balance of Planning Period FTR Auctions during the first seven months of the 2008 to 2009 planning period. The top 10 positive revenue producing FTR sources accounted for $146.7 million and 13.4 percent of all FTRs bought in the auctions. The top 10 negative revenue producing FTR sources accounted for -$69.2 million of revenue and constituted 2.9 percent of all FTRs bought in the auctions.

Figure 8-8 Ten largest positive and negative revenue producing FTR sources purchased in the Monthly Balance of Planning Period FTR Auctions: Planning period 2008 to 2009 through December 31, 2008



Revenue Adequacy

Congestion revenue is created in an LMP system when all loads pay and all generators receive their respective LMPs. When load pays more than the amount that generators receive, excluding losses, positive congestion revenue exists and is available to cover the target allocations of FTR holders. The MW of load exceeds the MW of generation in constrained areas because a part of the load is served by imports using transmission capability into the constrained areas. Generating units that are the source of such imports are paid the price at their own bus which does not reflect congestion in constrained areas. Generation in a constrained area receives the congestion price and all load in the constrained area pays the congestion price. As a result, load congestion payments are usually greater than the congestion-related increase in payments to generation.[33] In general, FTR revenue adequacy exists when the sum of congestion credits is as great as the sum of congestion across the positively valued FTRs.

Revenue adequacy must be distinguished from the adequacy of FTRs as a hedge against congestion. Revenue adequacy is a narrower concept that compares the revenues available to cover congestion across specific paths for which FTRs were available and purchased. The adequacy of FTRs as a hedge against congestion compares FTR revenues to total congestion on the system as a measure of the extent to which FTRs hedged market participants against actual, total congestion across all paths, regardless of the availability or purchase of FTRs.

FTRs are paid out for each month from congestion revenues, FTR auction revenues and excess revenues carried forward from prior months and distributed back from later months. At the end of a planning period, if some months remain not fully funded, an uplift charge is collected from any FTR market participants that hold FTRs during the planning period based on their pro rata share of total net positive FTR target allocations, excluding any charge to FTR holders with a net negative FTR position for the planning year. For the 2007 to 2008 planning period, FTRs were fully funded and thus no uplift charge was collected. Table 8-18 shows the composition of FTR target allocations and FTR revenues for the 2007 to 2008 and the 2008 to 2009 planning periods, with the latter shown through December 31, 2008. FTR targets are composed of FTR target allocations and associated adjustments. Other adjustments may be made for items such as modeling changes or errors.

FTR revenues are primarily comprised of hourly congestion revenue and net negative congestion. FTR revenues also include ARR excess which is the difference between ARR target allocations and FTR auction revenues. Competing use revenues are based on the Unscheduled Transmission Service Agreement between the New York Independent System Operator (NYISO) and PJM. This agreement sets forth the terms and conditions under which compensation is provided for transmission service in connection with transactions not scheduled directly or otherwise prearranged between NYISO and PJM. Congestion revenues appearing in Table 8-18 include both congestion charges associated with PJM facilities and those associated with reciprocal, coordinated flowgates in the Midwest ISO whose operating limits are respected by PJM.[34] The operating protocol governing the wheeling contracts between Public Service Electric and Gas Company (PSE&G) and Consolidated Edison Company of New York (Con Edison) resulted in a reimbursement of $2.3 million in congestion charges to Con Edison in the 2008 to 2009 planning period through December 31, 2008.[35,36]

33 For an illustration of how total congestion revenue is generated and how FTR target allocations and congestion receipts are determined, see Table G-1, "Congestion revenue, FTR target allocations and FTR congestion credits: Illustration," *2008 State of the Market Report*, Volume II, Appendix G, "Financial Transmission and Auction Revenue Rights."

34 See "Joint Operating Agreement between the Midwest Independent System Operator, Inc. and PJM Interconnection, L.L.C." (November 1, 2007) (Accessed February 24, 2009), Section 6.1 <http://www.pjm.com/~/Media/documents/agreements/joa-complete.ashx> (1,528 KB).

35 111 FERC ¶ 61,228 (2005).

36 See the *2008 State of the Market Report*, Volume II, Section 4, "Interchange Transactions," at "Con Edison and PSE&G Wheeling Contracts 2008 Update" and Appendix D, "Interchange Transactions" at Table D-1, "Con Edison and PSE&G wheel settlements data: Calendar year 2008."

Table 8-18 Total annual PJM FTR revenue detail (Dollars (Millions)): Planning periods 2007 to 2008 and 2008 to 2009

Accounting Element	2007/2008	2008/2009*
ARR information		
ARR target allocations	$1,651.7	$1,384.4
FTR auction revenue	$1,736.1	$1,458.3
ARR excess	$84.4	$73.9
FTR targets		
FTR target allocations	$2,039.0	$1,363.9
Adjustments:		
Adjustments to FTR target allocations	($6.1)	($3.6)
Total FTR targets	$2,032.9	$1,360.3
FTR revenues		
ARR excess	$84.4	$73.9
Competing uses	$1.0	$0.6
Congestion		
Net Negative Congestion	($16.3)	($36.2)
Hourly congestion revenue	$2,005.9	$1,355.3
Midwest ISO M2M (credit to PJM minus credit to Midwest ISO)	($15.8)	($38.2)
Consolidated Edison Company of New York and Public Service Electric and Gas Company Wheel (CEPSW) congestion credit to Con Edison	($2.9)	($2.3)
Adjustments		
Excess revenues carried forward into future months	$516.9	$22.0
Excess revenues distributed back to previous months	$0.0	$8.4
Other adjustments to FTR revenues	$0.4	$1.9
Total FTR revenues	$2,573.7	$1,385.2
Excess revenues distributed to other months	($540.9)	($30.4)
Excess revenues distributed to CEPSW for end-of-year distribution	$0.0	$0.0
Excess revenues distributed to FTR holders	$26.3	$0.0
Total FTR congestion credits	$2,032.9	$1,354.8
Total congestion credits on bill (includes CEPSW and end-of-year distribution)	$2,062.0	$1,357.2
Remaining deficiency	$0.0	$5.5

* Shows seven months ended 31-Dec-08

FTR target allocations are based on hourly prices in the Day-Ahead Energy Market for the respective FTR paths and equal the revenue required to hedge FTR holders fully against congestion on the specific paths for which the FTRs are held. FTR credits are paid to FTR holders and, depending on market conditions, can be less than the target allocations. Table 8-19 lists the FTR revenues, target allocations, credits, payout ratios, congestion credit deficiencies and excess congestion charges by month. At the end of the 12-month planning period, excess congestion charges are used to offset any monthly congestion credit deficiencies. FTRs were paid at 100 percent of the target allocation level for the 2007 to 2008 planning period and were paid at 99.6 percent of the target allocation level for the 2008 to 2009 planning period through December 31, 2008.

The total row in Table 8-19 is not the simple sum of each of the monthly rows because the monthly rows may include excess revenues carried forward from prior months and excess revenues carried back from later months. For example, September 2008 FTR revenues are shown as $152.0 million, which includes revenues from congestion charges for the month, excess revenues carried forward from prior months ($14.2 million) and excess revenues carried back from later months ($4.7 million).[37] For the 2007 to 2008 planning period, the total FTR revenues were $2,059.2 million which is the sum of total FTR credits ($2,032.9 million) and total excess credits ($26.3 million). For the first seven months of the 2008 to 2009 planning period, the total FTR revenues were $1,354.8 million, which equal the total FTR credits ($1,354.8 million) because there were credit deficiencies of $5.5 million.

37 The *2007 State of the Market Report* incorrectly reported the totals as the simple sum of the monthly rows in Table 8-14.

Table 8-19 Monthly FTR accounting summary (Dollars (Millions)): Planning periods 2007 to 2008 and 2008 to 2009

		FTR Revenues	FTR Target Allocations	FTR Credits	FTR Payout Ratio	Credits Deficiency	Credits Excess
Planning period 2007 to 2008	Jun-07	$193.0	$178.1	$178.1	100%	$0	$14.9
	Jul-07	$227.9	$178.9	$178.9	100%	$0	$48.9
	Aug-07	$264.8	$206.3	$206.3	100%	$0	$58.5
	Sep-07	$199.0	$134.2	$134.2	100%	$0	$64.8
	Oct-07	$192.0	$130.6	$130.6	100%	$0	$61.4
	Nov-07	$180.4	$132.0	$132.0	100%	$0	$48.5
	Dec-07	$275.7	$235.3	$235.3	100%	$0	$40.3
	Jan-08	$277.8	$238.6	$238.6	100%	$0	$39.2
	Feb-08	$213.3	$158.5	$158.5	100%	$0	$54.8
	Mar-08	$148.1	$94.8	$94.8	100%	$0	$53.4
	Apr-08	$185.7	$155.7	$155.7	100%	$0	$29.9
	May-08	$216.1	$189.8	$189.8	100%	$0	$26.3
	Summary for Planning Period 2007 to 2008						
	Total	$2,059.2	$2,032.9	$2,032.9	100%	$0	$26.3
Planning Period 2008 to 2009 (through December 31, 2008)	Jun-08	$434.9	$432.3	$432.3	100%	$0	$2.6
	Jul-08	$369.4	$364.2	$364.2	100%	$0	$5.2
	Aug-08	$139.2	$125.0	$125.0	100%	$0	$14.2
	Sep-08	$152.0	$154.6	$152.0	98.3%	$2.6	$0.0
	Oct-08	$108.2	$109.4	$108.2	98.9%	$1.2	$0.0
	Nov-08	$95.6	$97.2	$95.6	98.3%	$1.6	$0.0
	Dec-08	$86.0	$77.6	$77.6	100%	$0	$8.4
	Summary for Planning Period 2008 to 2009 through December 31, 2008						
	Total	$1,354.8	$1,360.3	$1,354.8	99.6%	$5.5	$0.0

FTR target allocations were examined separately. Hourly FTR target allocations were divided into those that were benefits and liabilities and summed by sink and by source for the 2008 to 2009 planning period through December 31, 2008. Figure 8-9 shows the FTR sinks with the largest positive and negative target allocations. The top 10 sinks that produced a financial benefit accounted for 69.1 percent of total positive target allocations during the first seven months of the 2008 to 2009 planning period. FTRs with the AP Control Zone as the sink included 24.3 percent of all positive target allocations. The sinks with the highest positive target allocations are all control zones or large aggregates. The top 10 sinks that created liability accounted for 37.4 percent of total negative target allocations. FTRs with the Western Hub as the sink encompassed 10.3 percent of all negative target allocations.

Figure 8-9 Ten largest positive and negative FTR target allocations summed by sink: Planning period 2008 to 2009 through December 31, 2008

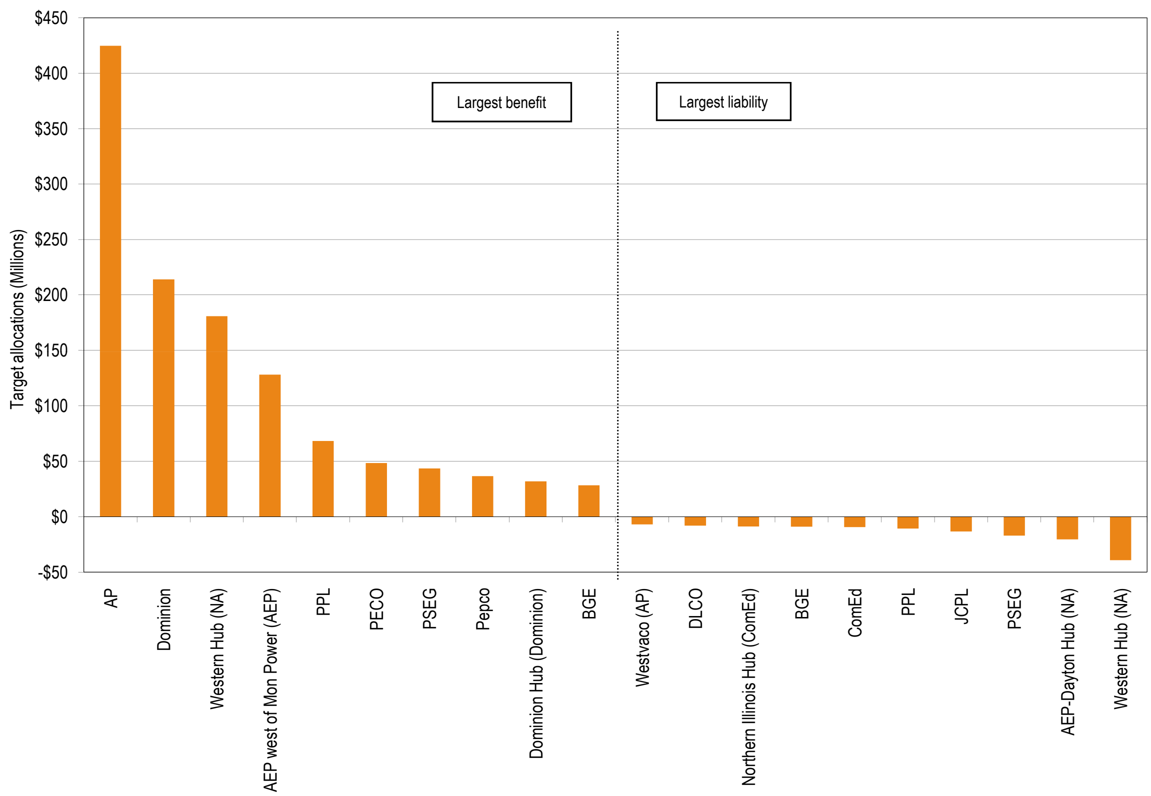
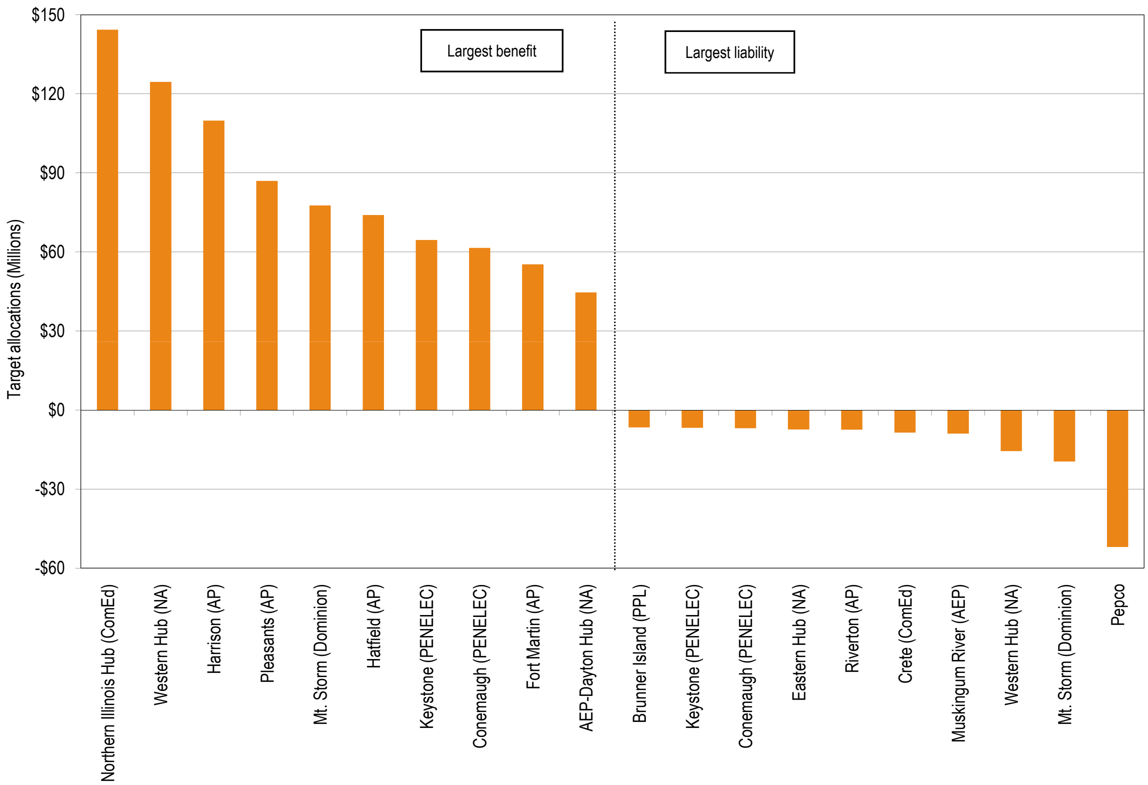


Figure 8-10 shows the FTR sources with the largest positive and negative target allocations during the first seven months of the 2008 to 2009 planning period. The top 10 sources with a positive target allocation accounted for 48.4 percent of total positive target allocations. FTRs with the Northern Illinois Hub as their source included 8.3 percent of all positive target allocations. The top 10 sources with a negative target allocation accounted for 36.6 percent of total negative target allocations. FTRs with the Pepco Control Zone as the source encompassed 13.7 percent of all negative target allocations.

Figure 8-10 Ten largest positive and negative FTR target allocations summed by source: Planning period 2008 to 2009 through December 31, 2008



Auction Revenue Rights

FTRs and ARRs are both financial instruments that entitle the holder to receive revenues or to pay charges based on nodal price differences. FTRs provide holders with revenues or charges based on the locational congestion price differences actually experienced in the Day-Ahead Energy Market while ARRs are financial instruments that entitle their holders to receive revenue or to pay charges based on prices determined in the Annual FTR Auction.[38] These price differences are based on the bid prices of participants in the Annual FTR Auction which relate to their expectations about the level of congestion in the Day-Ahead Energy Market. The auction clears the set of feasible FTR bids which produce the highest net revenue. In other words, ARR revenues are a function of FTR auction participants' expectations of locational congestion price differences in the Day-Ahead Energy Market.

ARRs are available to the nearest 0.1 MW. The ARR target allocation is equal to the product of the ARR MW and the price difference between sink and source from the Annual FTR Auction. An ARR value can be positive or negative depending on the sink-minus-source price difference, with a negative difference resulting in a liability for the holder. The ARR target allocation represents the revenue that an ARR holder should receive. All ARR holders receive ARR credits equal to their target allocations if total net revenues from the Long Term, Annual and Monthly Balance of Planning Period FTR Auctions are greater than, or equal to, the sum of all ARR target allocations. ARR credits can be positive or negative and can range from zero to the ARR target allocation. If the combined net revenues from the Long Term, Annual and Monthly Balance of Planning Period FTR Auctions are less than that, available revenue is proportionally allocated among all ARR holders.

ARRs are available only as obligation hedge type and 24-hour class type products. An ARR obligation provides a credit, positive or negative, equal to the product of the ARR MW and the price difference between ARR sink and source that occurs in the Annual FTR Auction. The 24-hour products are effective 24 hours a day, seven days a week.

When a new control zone is integrated into PJM, the participants in that control zone must choose to receive either an FTR allocation or an ARR allocation before the start of the Annual FTR Auction for two consecutive planning periods following their integration date. After the transition period, such participants receive ARRs from the annual allocation process and are ineligible for directly allocated FTRs.

Market Structure

ARRs have been available to network service and firm, point-to-point transmission service customers since June 1, 2003, when the annual ARR allocation was first implemented for the 2003 to 2004 planning period. The initial allocation covered the Mid-Atlantic Region and the AP Control Zone. For the 2006 to 2007 planning period, the choice of ARRs or direct allocation FTRs was available to eligible market participants in the AEP, DAY, DLCO and Dominion control zones. For the 2007 to 2008 and subsequent planning periods, all eligible market participants were allocated ARRs.

38 These nodal prices are a function of the market participants' annual FTR bids and binding transmission constraints. An optimization algorithm selects the set of feasible FTR bids that produces the most net revenue.

Supply

ARR supply is limited by the capability of the transmission system to simultaneously accommodate the set of requested ARRs and the numerous combinations of ARRs that are feasible.

ARR Allocation

For the 2007 to 2008 planning period, the annual ARR allocation process was revised to include Long Term ARRs that would be in effect for 10 consecutive planning periods.[39] Long Term ARRs can give LSEs the ability to hedge their congestion costs on a long-term basis by providing price certainty throughout the 10 planning period time frame. Long Term ARR holders can opt out of any planning period during the 10 planning period timeline and self schedule their Long Term ARRs as FTRs.

Each March, PJM allocates ARRs to eligible customers in a three-stage process, whereby the first and second stages are each one round and the third stage is a three-round allocation procedure:

- **Stage 1A.** In the first stage of the allocation, network transmission service customers can obtain Long Term ARRs, up to their share of the zonal base load, after taking into account generation resources that historically have served load in each control zone and up to 50 percent of their historical nonzone network load. Nonzone network load is load that is located outside of the PJM footprint. Firm, point-to-point transmission service customers can obtain Long Term ARRs, based on up to 50 percent of the MW of long-term, firm, point-to-point transmission service provided between the receipt and delivery points for the historical reference year. Stage 1A ARR holders can also opt out of any planning period during the 10-planning-period timeline and self schedule their Long Term ARRs as FTRs.

- **Stage 1B.** ARRs unallocated in Stage 1A are available in the Stage 1B allocation. Network transmission service customers can obtain ARRs, up to their share of the zonal peak load, based on generation resources that historically have served load in each control zone and up to 100 percent of their transmission responsibility for nonzone network load. Firm, point-to-point transmission service customers can obtain ARRs based on the MW of long-term, firm, point-to-point service provided between the receipt and delivery points for the historical reference year. These long-term point-to-point service agreements must also remain in effect for the planning period covered by the allocation.

- **Stage 2.** The third stage of the annual ARR allocation is a three-step procedure, with one-third of the remaining system capability allocated in each step of the process. Network transmission service customers can obtain ARRs from any hub, control zone, generator bus or interface pricing point to any part of their aggregate load in the control zone or load aggregation zone for which an ARR was not allocated in Stage 1A or Stage 1B. Firm, point-to-point transmission service customers can obtain ARRs consistent with their transmission service as in Stage 1A and Stage 1B.

39 See the *2006 State of the Market Report* (March 8, 2007) for the rules of the annual ARR allocation process for the 2006 to 2007 and prior planning periods.

Prior to the start of the Stage 2 annual ARR allocation process, ARR holders can relinquish any portion of their ARRs resulting from the Stage 1A or Stage 1B allocation process, provided that all remaining outstanding ARRs are simultaneously feasible following the return of such ARRs.[40] Participants may seek additional ARRs in the Stage 2 allocation.

ARRs can also be traded between LSEs, but these trades must be made before the first round of the Annual FTR Auction. LSEs trading ARRs must trade all of their ARRs associated with a control zone and their zonal network service peak load is also reassigned to the new LSE. Traded ARRs are effective for the full 12-month planning period.

When ARRs are allocated, all ARRs must be simultaneously feasible to ensure that the physical transmission system can support the approved set of ARRs. In making simultaneous feasibility determinations, PJM utilizes a power flow model of security-constrained dispatch that takes into account generation and transmission facility outages and is based on reasonable assumptions about the configuration and availability of transmission capability during the planning period.[41] This simultaneous feasibility requirement is necessary to ensure that there are sufficient revenues from transmission congestion charges to satisfy all resulting ARR obligations, thereby preventing underfunding of the ARR obligations for a given planning period. If the requested set of ARRs is not simultaneously feasible, customers are allocated prorated shares in direct proportion to their requested MW and in inverse proportion to their impact on binding constraints:

Equation 8-1 Calculation of prorated ARRs

Individual prorated MW = (Constraint capability) • (Individual requested MW / Total requested MW) • (1 / MW effect on line).[42]

The effect of an ARR request on a binding constraint is measured using the ARR's power flow distribution factor. An ARR's distribution factor is the percent of each requested MW of ARR that would have a power flow on the binding constraint. The PJM methodology prorates those ARR requests with the greatest impact on the binding constraint to avoid prorating more requests but having smaller or minimal impact on the binding constraint. PJM's method results in the prorating of ARRs that cause the greatest flows on the binding constraint instead of those that produce less flow on it. Were all ARR requests prorated equally, irrespective of their proportional impact on the binding constraints, the result would be a significant reduction in market participants' ARRs even when they have little impact on the binding constraints and the reduction of ARRs, and their associated benefits, with primary impacts on unrelated constraints.

40 PJM. "Manual 6: Financial Transmission Rights," Revision 11 (August 1, 2008), pp. 20-23.
41 PJM. "Manual 6: Financial Transmission Rights," Revision 11 (August 1, 2008), pp. 49-50.
42 See the *2008 State of the Market Report*, Volume II, Appendix G, "Financial Transmission Rights and Auction Revenue Rights," for an illustration explaining this calculation in greater detail.

Residual ARRs

On June 19, 2007, PJM submitted to the FERC revisions to the OATT to include a new type of ARR known as a residual ARR.[43] On August 13, 2007, the FERC issued an order accepting the revisions to the PJM OATT with an effective date of August 20, 2007.[44] Only ARR holders that had their Stage 1A or Stage 1B ARRs prorated are eligible to receive residual ARRs. Residual ARRs would be available if additional transmission system capability were added during the planning period after the annual ARR allocation. This additional transmission system capability would not have been accounted for in the initial annual ARR allocation, but it enables the creation of residual ARRs. Residual ARRs would be effective on the first day of the month in which the additional transmission system capability is included in FTR auctions and would exist until the end of the planning period. For the following planning period, any residual ARRs would be available as ARRs in the annual ARR allocation process as they would be included in the power flow model. The amount of a residual ARR would be the difference between the ARR holder's Stage 1A or Stage 1B request and their actual prorated Stage 1A or Stage 1B ARR MW. Stage 1 ARR holders have a priority right to ARRs and those holders who had ARRs prorated because of the simultaneous feasibility requirement previously had no recourse from the impact of proration. Residual ARRs are a separate product from incremental ARRs. No residual ARRs have been allocated to date.

Incremental ARRs

Market participants constructing generation interconnection or transmission expansion projects may request an allocation of incremental ARRs consistent with the project's increased transmission capability.[45] Incremental ARRs are available in a three-round allocation process with a single point-to-point combination requested and one-third of the incremental ARR MW allocated in each round. Incremental ARRs can be accepted or refused after rounds one and two. If accepted, that ARR is removed from availability in subsequent rounds; if it is refused, that ARR is available in the next rounds. Such incremental ARRs are effective for the lesser of 30 years or the life of the facility or upgrade. At any time during this 30-year period, in place of continuing this 30-year ARR, the participant has a single opportunity to replace the allocated ARRs with a right to request ARRs during the annual ARR allocation process between the same source and sink. Such participants can also permanently relinquish their incremental ARRs at any time during the life of the ARRs as long as overall the system simultaneous feasibility can be maintained.

Table 8-20 lists the incremental ARR allocation volume for the 2007 to 2008 and the 2008 to 2009 planning periods. For the 2008 to 2009 planning period, there were 891 MW bids and 100 percent of the bids were cleared. For the 2007 to 2008 planning period, there were 374 MW bids and 100 percent of the bids were cleared.

43 *PJM Interconnection, L.L.C.*, PJM Interconnection, L.L.C. submits revisions to its Amended and Restated Operating Agreement and Open Access Transmission Tariff pursuant to Section 205 of the Federal Power Act, Docket No. ER07-1053-000 (June 19, 2007).

44 *PJM Interconnection, L.L.C.*, Letter Order accepting PJM Interconnection, L.L.C.'s June 19, 2007, filing of Second Revised Sheet No. 6A *et al* to the Third Revised Rate Schedule, FERC No. 24 *et al*, Docket No. ER07-1053-000 (August 13, 2007).

45 PJM. "Manual 6: Financial Transmission Rights," Revision 11 (August 1, 2008), pp. 27-28.

Table 8-20 Incremental ARR allocation volume: Planning periods 2007 to 2008 and 2008 to 2009

Planning Period	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
2007/2008	13	374	374	100%	0	0%
2008/2009	15	891	891	100%	0	0%

Table 8-21 lists the top 10 principal binding constraints, along with their corresponding control zones in order of severity, that limited supply in the annual ARR allocation for the 2008 to 2009 planning period. The order of severity is determined by the violation degree of the binding constraint as computed in the simultaneous feasibility test.[46] The violation degree is a measure of the MW that a constraint is over the limit for a type of facility; a higher number indicates a more severe constraint.

Table 8-21 Top 10 principal binding transmission constraints limiting the annual ARR allocation: Planning period 2008 to 2009

Constraint	Type	Control Zone
AP South	Interface	AP
Cedar Grove - Clifton	Line	PSEG
Amos	Transformer	AEP
Elrama - Mitchell	Line	DLCO
Perryman	Transformer	BGE
Conesville Prep - Conesville	Line	AEP
Lanesville	Transformer	External
Doubs	Transformer	AP
Crane - Windy Edge	Line	BGE
Dresden	Transformer	ComEd

Demand

PJM's OATT specifies the types of transmission services that are available to eligible customers. Eligible customers submit requests to PJM for network and firm, point-to-point transmission service through the PJM Open Access Same-Time Information System (OASIS). ARRs associated with firm transmission service that spans the entire next planning period, outside of the annual ARR allocation window, can also be requested through the PJM OASIS.[47] PJM evaluates each transmission service request for its impact on the system and approves or denies the request accordingly. All approved transmission services can be accommodated by the PJM transmission system. Theoretically, since total eligible ARR demand for the system cannot exceed the combined MW of network and firm, point-to-point transmission service, ARR supply should equal ARR demand if ARR nominations are consistent with the historic use of the transmission system. However, the demand for some ARRs

46 PJM. "Manual 6: Financial Transmission Rights," Revision 11 (August 1, 2008), pp. 49-50.
47 PJM. "Manual 6: Financial Transmission Rights," Revision 11 (August 1, 2008), pp. 16-17.

could be left unmet if the same resources are nominated as ARR source points by multiple parties for delivery across shared paths and the result exceeds the stated capability of the transmission system to deliver from those sources to load. The combination might not be simultaneously feasible. When the requested set of ARRs is not simultaneously feasible, customers are allocated prorated shares in direct proportion to their requested MW and in inverse proportion to their impact on binding constraints.

ARR Reassignment for Retail Load Switching

Current PJM rules provide that when load switches among LSEs during the planning period, a proportional share of associated ARRs that sink into a given control or load aggregation zone is automatically reassigned to follow that load.[48] ARR reassignment occurs daily only if the LSE losing load has ARRs with a net positive economic value to that control zone. An LSE gaining load in the same control zone is allocated a proportional share of positively valued ARRs within the control zone based on the shifted load. ARRs are reassigned to the nearest 0.001 MW and any MW of load may be reassigned multiple times over a planning period. Residual ARRs are also subject to the rules of ARR reassignment. This practice supports competition by ensuring that the hedge against congestion follows load, thereby removing a barrier to competition among LSEs and, by ensuring that only ARRs with a positive value are reassigned, preventing an LSE from assigning poor ARR choices to other LSEs. However, when ARRs are self scheduled as FTRs, these underlying self scheduled FTRs do not follow load that shifts while the ARRs do follow load that shifts, and this may diminish the value of the hedge. When load shifts from one LSE to another in newly integrated control zones, directly allocated FTRs with positive economic value follow the load.[49]

Table 8-22 summarizes ARR MW and associated revenue automatically reassigned for network load in each control zone where changes occurred between June 2007 and December 2008. About 10,017 MW of ARRs associated with $353,300 per MW-day of revenue were automatically reassigned in the first seven months of the 2008 to 2009 planning period. About 14,011 MW of ARRs with $408,000 per MW-day of revenue were reassigned for the entire 12-month 2007 to 2008 planning period.

48 PJM. "Manual 6: Financial Transmission Rights," Revision 11 (August 1, 2008), p. 25.
49 PJM. "Manual 6: Financial Transmission Rights," Revision 11 (August 1, 2008), p. 33.

Table 8-22 ARRs and ARR revenue automatically reassigned for network load changes by control zone: June 1, 2007, to December 31, 2008

	ARRs Reassigned (MW-day)		ARR Revenue Reassigned [Dollars (Thousands) per MW-day]	
Control Zone	2007/2008 (12 months)	2008/2009 (7 months)*	2007/2008 (12 months)	2008/2009 (7 months)*
AECO	169	119	$4.5	$3.6
AEP	62	10	$1.6	$0.1
AP	1,005	456	$189.5	$112.0
BGE	2,923	2,623	$77.2	$95.3
ComEd	3,800	1,841	$8.4	$5.6
DAY	0	1	$0.0	$0.0
DLCO	516	188	$0.7	$0.9
Dominion	21	4	$0.0	$0.3
DPL	1,413	1,131	$20.4	$19.7
JCPL	582	653	$11.3	$26.4
Met-Ed	3	NA	$0.1	NA
PECO	44	30	$1.5	$0.9
PENELEC	3	NA	$0.1	NA
Pepco	2,232	2,215	$48.6	$57.7
PPL	14	1	$0.4	$0.1
PSEG	1,185	732	$43.3	$30.6
RECO	40	14	$0.3	$0.0
Total	14,011	10,017	$408.0	$353.3

* Through 31-Dec-08

Market Performance

Volume

Table 8-23 lists the annual ARR allocation volume by stage and round for the 2007 to 2008 and the 2008 to 2009 planning periods. For the 2008 to 2009 planning period, there were 64,546 MW (45.9 percent of total demand) bid in Stage 1A, 27,291 MW (19.4 percent of total demand) bid in Stage 1B and 48,831 MW (34.7 percent of total demand) bid in Stage 2. Of 140,668 MW in total ARR requests, 64,520 MW were allocated in Stage 1A and 26,685 MW were allocated in Stage 1B while 20,806 MW were allocated in Stage 2 for a total of 112,011 MW (79.6 percent) allocated. Eligible market participants subsequently converted 72,851 MW of these allocated ARRs into Annual FTRs (65.0 percent of total allocated ARRs), leaving 39,159 MW of ARRs outstanding. For the 2007 to 2008 planning period, there had been 62,220 MW (41.3 percent of total demand) bid in Stage 1A, 31,063 MW (20.6 percent of total demand) bid in Stage 1B and 57,539 MW (38.1 percent of total demand) bid in Stage 2. Of 150,822 MW in total ARR requests, 62,211 MW were allocated in

Stage 1A and 29,444 MW were allocated in Stage 1B while 16,337 MW were allocated in Stage 2 for a total of 107,992 MW (71.6 percent) allocated. There were 71,360 MW or 66.1 percent of the allocated ARRs converted into FTRs. Immediately after the Stage 1B ARR allocation for the 2008 to 2009 planning period, ARR holders relinquished 26.8 MW of the allocated Stage 1A ARRs and 0.3 MW of the allocated Stage 1B ARRs. In comparison, for the 2007 to 2008 planning period, ARR holders relinquished 9.6 MW of the allocated Stage 1A ARRs and 459.7 MW of the allocated Stage 1B ARRs. The uncleared volume in Table 8-23 includes ARRs that were relinquished.

Table 8-23 Annual ARR allocation volume: Planning periods 2007 to 2008 and 2008 to 2009

Planning Period	Stage	Round	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
2007/2008	1A	0	7,578	62,220	62,211	100.0%	9	0.0%
	1B	1	3,486	31,063	29,444	94.8%	1,619	5.2%
	2	2	1,922	19,360	4,043	20.9%	15,317	79.1%
		3	1,466	19,312	5,211	27.0%	14,101	73.0%
		4	1,072	18,867	7,083	37.5%	11,784	62.5%
		Total	4,460	57,539	16,337	28.4%	41,202	71.6%
	Total		15,524	150,822	107,992	71.6%	42,830	28.4%
2008/2009	1A	0	7,845	64,546	64,520	100.0%	26	0.0%
	1B	1	3,147	27,291	26,685	97.8%	606	2.2%
	2	2	1,691	16,737	6,753	40.3%	9,984	59.7%
		3	1,312	15,464	6,304	40.8%	9,160	59.2%
		4	1,118	16,630	7,749	46.6%	8,881	53.4%
		Total	4,121	48,831	20,806	42.6%	28,025	57.4%
	Total		15,113	140,668	112,011	79.6%	28,657	20.4%

Revenue

As ARRs are allocated to qualifying customers rather than sold, there is no ARR revenue comparable to the revenue that results from the FTR auctions.

Revenue Adequacy

The degree to which ARR credits provide a hedge against congestion on specific ARR paths is determined by the prices that result from the Annual FTR Auction. The resultant ARR credit could be greater than, less than, or equal to the actual congestion on the selected path. This is the same concept as FTR revenue adequacy.

Customers that are allocated ARRs can choose to retain the underlying FTRs linked to their ARRs through a process termed self scheduling. Just like any other FTR, the underlying FTRs have a target hedge value based on actual day-ahead congestion on the selected path.

As with FTRs, revenue adequacy for ARRs must be distinguished from the adequacy of ARRs as a hedge against congestion. Revenue adequacy is a narrower concept that compares the revenues available to cover congestion across specific paths for which ARRs were available and allocated. The adequacy of ARRs as a hedge against congestion compares ARR revenues to total congestion sinking in the participant's load zone as a measure of the extent to which ARRs hedged market participants against actual, total congestion into their zone, regardless of the availability or allocation of ARRs.

ARR holders will receive $2,361.3 million in credits from the Annual FTR Auction during the 2008 to 2009 planning period, with an average hourly ARR credit of $2.41 per MWh. During the comparable 2007 to 2008 planning period, ARR holders received $1,640.5 million in ARR credits, with an average hourly ARR credit of $1.73 per MWh.

Table 8-24 lists ARR target allocations and net revenue sources from the Annual and Monthly Balance of Planning Period FTR Auctions for the 2007 to 2008 and the 2008 to 2009 (through December 31, 2008) planning periods. Annual FTR Auction net revenue has been sufficient to cover ARR target allocations for both planning periods. The 2008 to 2009 planning period's Annual and Monthly Balance of Planning Period FTR Auctions generated a surplus of $123.5 million in auction net revenue through December 31, 2008, above the amount needed to pay 100 percent of ARR target allocations. The whole 2007 to 2008 planning period's Annual and Monthly Balance of Planning Period FTR Auctions generated a surplus of $95.6 million in auction net revenue, above the amount needed to pay 100 percent of ARR target allocations.

Table 8-24 ARR revenue adequacy (Dollars (Millions)): Planning periods 2007 to 2008 and 2008 to 2009

	2007/2008	2008/2009
Total FTR auction net revenue	$1,736.1	$2,484.8
Annual FTR Auction net revenue	$1,698.0	$2,422.6
Monthly Balance of Planning Period FTR Auction net revenue*	$38.1	$62.2
ARR target allocations	$1,640.5	$2,361.3
ARR credits	$1,640.5	$2,361.3
Surplus auction revenue	$95.6	$123.5
ARR payout ratio	100%	100%
FTR payout ratio*	100%	99.6%

* Shows twelve months for 2007/2008 and seven months ended 31-Dec-08 for 2008/2009

ARR Proration

During the annual ARR allocation process, all ARRs must be simultaneously feasible to ensure that the physical transmission system can support the approved set of ARRs. If all the ARR requests made during the annual ARR allocation process are not feasible, then ARRs are prorated and allocated in proportion to the MW level requested and in inverse proportion to the effect on the binding constraints.[50,51]

When ARRs were allocated for the 2008 to 2009 planning period, some of the requested ARRs were prorated in order to ensure simultaneous feasibility. There were no ARRs prorated in Stage 1A of the annual ARR allocation. The Cedar Grove — Clifton line was the only binding constraint in Stage 1B of the annual ARR allocation, leading to 605.4 MW of proration.

A number of factors caused the proration of requested ARRs on the Cedar Grove — Clifton line. They include an increase in ARR requests for congested paths on the Cedar Grove — Clifton line, general load growth and increased unscheduled transmission flow across the PJM system from external sources.

ARR and FTR Revenue and Congestion

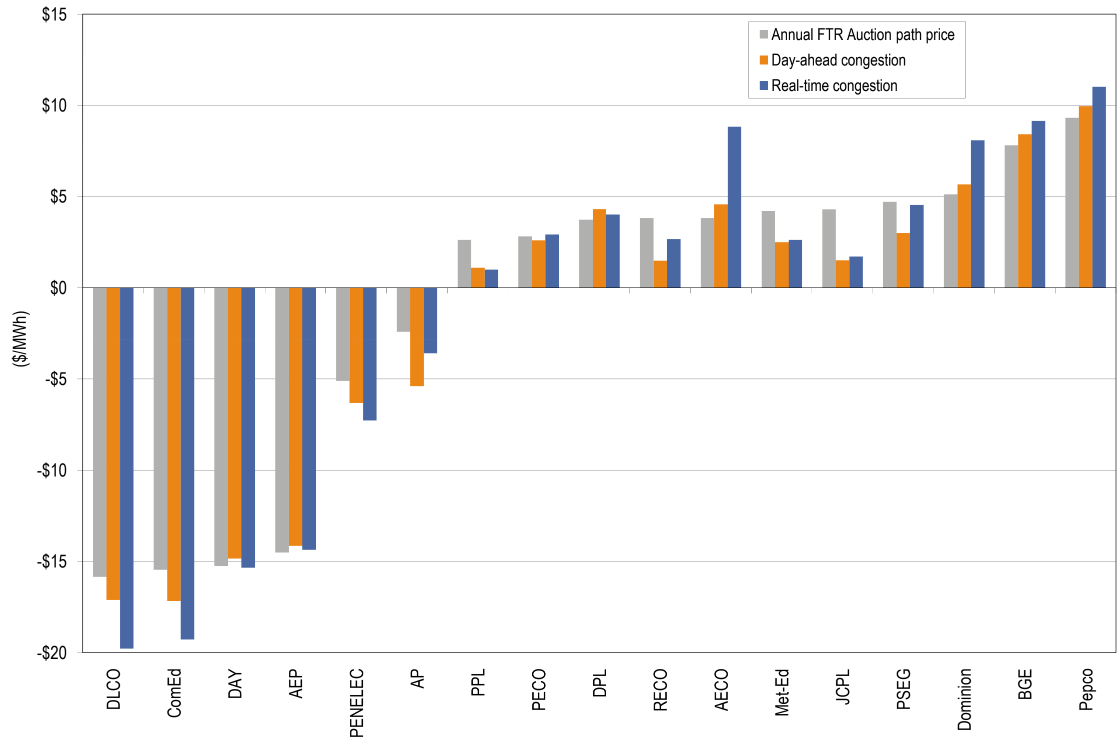
FTR Prices and Zonal Price Differences

As an illustration of the relationship between FTRs and congestion, Figure 8-11 shows Annual FTR Auction prices and an approximate measure of day-ahead and real-time congestion for each PJM control zone for the 2008 to 2009 planning period through December 31, 2008. The day-ahead and real-time congestion are based on the difference between zonal congestion prices and Western Hub congestion prices. The figure shows, for example, that an FTR from the Western Hub to the PECO Control Zone cost $2.82 per MWh in the Annual FTR Auction and that about $2.61 per MWh of day-ahead congestion and $2.93 per MWh of real-time congestion existed between the Western Hub and the PECO Control Zone. The data show that congestion costs, approximated in this way, were positive for most control zones that are located east of the Western Hub while congestion costs were negative and were more negative than the negative price of FTRs for control zones that are located west of that hub.

50 PJM. “Manual 6: Financial Transmission Rights,” Revision 11 (August 1, 2008), pp. 24-25.

51 See the *2008 State of the Market Report*, Volume II, Appendix G, “Financial Transmission Rights and Auction Revenue Rights,” for an illustration explaining the ARR prorating method.

Figure 8-11 Annual FTR Auction prices vs. average day-ahead and real-time congestion for all control zones relative to the Western Hub: Planning period 2008 to 2009 through December 31, 2008



Effectiveness of ARRs as a Hedge against Congestion

One measure of the effectiveness of ARRs as a hedge against congestion is a comparison of the revenue received by the holders of ARRs and the congestion across the corresponding paths. The revenue which serves as a hedge for ARR holders comes from the FTR auctions while the hedge for FTR holders is provided by the congestion payments derived directly from the Day-Ahead Energy Market and the balancing energy market. Thus, ARRs are an indirect hedge against actual congestion in both the Day-Ahead Energy Market and the balancing energy market.

The comparison between the revenue received by ARR holders and the actual congestion experienced by these ARR holders in the Day-Ahead Energy Market and the balancing energy market is presented by control zone in Table 8-25. ARRs and self scheduled FTRs that sink at an aggregate are assigned to a control zone if applicable.[52] Total revenue equals the ARR credits and the FTR credits from ARRs which are self scheduled as FTRs. The ARR credits do not include the credits for the portion of any ARR that was self scheduled as an FTR since ARR holders purchase self scheduled FTRs in the Annual FTR Auction and that revenue is then paid back to the ARR holders, netting the transaction to zero. ARR credits are calculated as the product of the ARR MW (excludes any self scheduled FTR MW) and the sink-minus-source price difference for the ARR path from the Annual FTR Auction.

52 For Table 8-25 through Table 8-28, aggregates are separated into their individual bus components and each bus is assigned to a control zone. Aggregates that are external sinks are included in the PJM Control Zone.

FTR credits equal FTR target allocations adjusted by the FTR payout ratio. The FTR target allocation is equal to the product of the FTR MW and the congestion price differences between sink and source that occur in the Day-Ahead Energy Market. FTR credits are paid to FTR holders and, depending on market conditions, may be less than the target allocation. The FTR payout ratio equals the percentage of the target allocation that FTR holders actually receive as credits. The FTR payout ratio was 100 percent of the target allocation for the 2007 to 2008 planning period.

The "Congestion" column shows the amount of congestion in each control zone from the Day-Ahead Energy Market and the balancing energy market and includes only the congestion costs incurred by the organizations that hold ARRs or self scheduled FTRs. The last column shows the difference between the total revenue and the congestion for each ARR control zone sink.

Data shown are for the 2007 to 2008 planning period summed by ARR control zone sink. For example, the table shows that for the 2007 to 2008 planning period, ARRs allocated to the JCPL Control Zone received a total of $68.5 million in revenue which was the sum of $35.7 million in ARR credits and $32.8 million in credits for self scheduled FTRs. This total revenue was $132.9 million less than the congestion costs of $201.4 million from the Day-Ahead Energy Market and the balancing energy market incurred by organizations in the JCPL Control Zone that held ARRs or self scheduled FTRs.

Table 8-25 ARR and self scheduled FTR congestion hedging by control zone: Planning period 2007 to 2008

Control Zone	ARR Credits	Self-Scheduled FTR Credits	Total Revenue	Congestion	Total Revenue - Congestion Difference	Percent Hedged
AECO	$27,050,101	$4,490,071	$31,540,172	$60,130,175	($28,590,003)	52.5%
AEP	$3,754,071	$202,251,131	$206,005,202	$243,739,566	($37,734,364)	84.5%
AP	$43,158,145	$640,618,894	$683,777,039	$413,697,338	$270,079,701	>100%
BGE	$70,874,793	$5,361,140	$76,235,933	$29,266,225	$46,969,708	>100%
ComEd	$13,235,456	$1,553,338	$14,788,794	($29,855,762)	$44,644,556	>100%
DAY	$6,213,543	$1,680,770	$7,894,313	$19,809,086	($11,914,773)	39.9%
DLCO	$1,573,363	$2,083,428	$3,656,791	($2,805,029)	$6,461,820	>100%
Dominion	$21,799,543	$3,392,005	$25,191,548	$72,018,947	($46,827,399)	35.0%
DPL	$12,742,414	$220,914,957	$233,657,371	$535,233,722	($301,576,351)	43.7%
JCPL	$35,696,894	$32,821,391	$68,518,285	$201,449,625	($132,931,340)	34.0%
Met-Ed	$1,521,781	$38,152,860	$39,674,641	$96,271,148	($56,596,507)	41.2%
PECO	$5,914,429	$53,367,088	$59,281,517	($45,767,283)	$105,048,800	>100%
PENELEC	$3,106,417	$55,416,946	$58,523,363	$116,683,242	($58,159,879)	50.2%
Pepco	$45,101,300	$636,953	$45,738,253	$306,713,071	($260,974,818)	14.9%
PJM	$1,032,146	$13,505,210	$14,537,356	($26,523,041)	$41,060,397	>100%
PPL	$1,450,595	$55,557,156	$57,007,751	$7,236,991	$49,770,760	>100%
PSEG	$127,392,055	$17,579,934	$144,971,989	$117,052,931	$27,919,058	>100%
RECO	$1,951,540	$0	$1,951,540	$10,335,702	($8,384,162)	18.9%
Total	$423,568,586	$1,349,383,272	$1,772,951,858	$2,124,686,654	($351,734,796)	83.4%

During the 2007 to 2008 planning period, congestion costs associated with the 107,992 MW of allocated ARRs were $2,124.7 million. As Table 8-8 indicates, 71,360 MW of ARRs were converted into FTRs through the self scheduling option, with 36,632 MW remaining as ARRs. The 36,632 MW of remaining ARRs provided $423.6 million of ARR credits, representing a hedge of 19.9 percent of the $2,124.7 million in congestion costs incurred, while the self scheduled FTRs provided $1,349.4 million of revenue, hedging an additional 63.5 percent of congestion costs. Total congestion hedged by both was $1,773.0 million, or 83.4 percent. (See Table 8-25.) The effectiveness of ARRs as a hedge depends both on the ARR value which is a function of the FTR auction prices, on congestion patterns in the Day-Ahead and Real-Time Energy Markets and on the FTR payout ratio.

Effectiveness of FTRs as a Hedge against Congestion

FTRs provide a direct hedge against congestion costs. Table 8-26 compares the total FTR credits and the total FTR auction revenues that sink in each control zone and the congestion costs in each control zone for the 2007 to 2008 planning period. FTRs that sink at an aggregate or a bus are assigned to a control zone if applicable. The “FTR Credits” column represents the total FTR target allocations for FTRs that sink in each control zone from the Annual FTR Auction, the Monthly Balance of Planning Period FTR Auctions and any FTRs that were self scheduled from ARRs, adjusted by the FTR payout ratio. The FTR target allocation is equal to the product of the FTR MW and the congestion price differences between sink and source that occur in the Day-Ahead Energy Market. FTR credits are the product of the FTR target allocations and the FTR payout ratio. The FTR payout ratio was 100 percent of the target allocation for the 2007 to 2008 planning period. The “FTR Auction Revenue” column shows the amount paid for FTRs that sink in each control zone in the Annual FTR Auction, the Monthly Balance of Planning Period FTR Auctions and any self scheduled FTRs. The FTR hedge is the difference between the FTR credits and the FTR auction revenue. The “Congestion” column shows the total amount of congestion in the Day-Ahead Energy Market and the balancing energy market in each control zone. The last column shows the difference between the FTR hedge and the congestion for each control zone.

All FTRs provided a hedge of $302.8 million against $1,995.5 million in congestion costs incurred.[53] This demonstrates that all FTRs provided a 15.2 percent hedge against congestion costs in PJM. For example, the table shows that for the 2007 to 2008 planning period, all FTRs sunk in the Pepco Control Zone received a total of $266.0 million in FTR credits while these FTRs cost $218.6 million in the FTR auctions. This gives a total FTR hedge of $47.5 million against $177.1 million in congestion costs from the Day-Ahead Energy Market and the balancing energy market. This shows a deficit of $129.7 million in their total FTR hedge position versus the cost of congestion in the Day-Ahead Energy Market and the balancing energy market. It would not be expected that the value of the FTR hedge calculated in this manner would cover all congestion costs as both ARRs and FTRs are available to hedge total congestion. That comparison is provided in Table 8-27.

53 The congestion costs in Table 8-26, Table 8-27 and Table 8-28 (2007 to 2008 planning period) do not equal the congestion costs in Table 8-25 because the congestion costs for organizations that did not hold ARRs had negative congestion costs that lowered the total congestion costs compared to those of just the ARR holders.

Table 8-26 FTR congestion hedging by control zone: Planning period 2007 to 2008

Control Zone	FTR Credits	FTR Auction Revenue	FTR Hedge	Congestion	FTR Hedge - Congestion Difference	Percent Hedged
AECO	$33,818,154	$26,487,534	$7,330,620	$48,611,136	($41,280,516)	15.1%
AEP	$74,060,394	$122,461,520	($48,401,126)	$224,108,931	($272,510,057)	<0%
AP	$592,512,119	$491,764,536	$100,747,583	$462,376,328	($361,628,745)	21.8%
BGE	$63,409,285	$63,365,238	$44,047	$74,161,439	($74,117,392)	0.1%
ComEd	($64,942,926)	($30,250,928)	($34,691,998)	$215,858,584	($250,550,582)	<0%
DAY	($35,353,881)	($25,729,852)	($9,624,029)	$17,884,456	($27,508,485)	<0%
DLCO	($24,829,264)	($27,921,904)	$3,092,640	$11,410,848	($8,318,208)	27.1%
Dominion	$253,021,344	$196,207,169	$56,814,175	$283,479,504	($226,665,329)	20.0%
DPL	$27,834,839	$41,345,962	($13,511,123)	$56,034,968	($69,546,091)	<0%
JCPL	$289,812,635	$87,916,212	$201,896,423	$228,011,843	($26,115,420)	88.5%
Met-Ed	$56,186,522	$56,735,375	($548,853)	$52,663,379	($53,212,232)	<0%
PECO	$42,270,945	$94,973,373	($52,702,428)	($55,027,453)	$2,325,025	>100%
PENELEC	$242,914,519	$139,361,603	$103,552,916	$186,535,306	($82,982,390)	55.5%
Pepco	$266,025,285	$218,553,668	$47,471,617	$177,145,206	($129,673,589)	26.8%
PJM	$13,724,519	$13,853,916	($129,397)	($85,980,478)	$85,851,081	>100%
PPL	$53,460,555	$57,050,864	($3,590,309)	($14,546,632)	$10,956,323	>100%
PSEG	$148,445,275	$206,565,360	($58,120,085)	$102,416,667	($160,536,752)	<0%
RECO	$6,541,812	$3,398,262	$3,143,550	$10,333,202	($7,189,652)	30.4%
Total	$2,038,912,131	$1,736,137,908	$302,774,223	$1,995,477,234	($1,692,703,011)	15.2%

Effectiveness of ARRs and FTRs as a Hedge against Congestion

Table 8-27 compares the revenue for ARR and FTR holders and the congestion in both the Day-Ahead Energy Market and the balancing energy market for the 2007 to 2008 planning period. This compares the total hedge provided by all ARRs and all FTRs to the total congestion costs within each control zone. ARRs and FTRs that sink at an aggregate or a bus are assigned to a control zone if applicable. ARR credits are calculated as the product of the ARR MW and the sink-minus-source price difference for the ARR path from the Annual FTR Auction. The "FTR Credits" column represents the total FTR target allocation for FTRs that sink in each control zone from the Annual FTR Auction, the Monthly Balance of Planning Period FTR Auctions and any FTRs that were self scheduled from ARRs, adjusted by the FTR payout ratio. The FTR target allocation is equal to the product of the FTR MW and congestion price differences between sink and source that occur in the Day-Ahead Energy Market. FTR credits are the product of the FTR target allocations and the FTR payout ratio. The FTR payout ratio was 100 percent of the target allocation for the 2007 to 2008 planning period. The "FTR Auction Revenue" column shows the amount paid for FTRs that sink in each control zone in the Annual FTR Auction, the Monthly Balance of Planning Period FTR Auctions and any ARRs that were self scheduled as FTRs. ARR holders that self schedule FTRs purchased the FTRs in the Annual FTR Auction and that revenue was then paid back to those ARR holders through ARR credits on a monthly basis throughout the planning period, ultimately netting the transaction to zero. The total ARR and FTR hedge is the sum of the ARR credits and the FTR credits minus the FTR auction revenue. The “Congestion” column shows the total amount of congestion in the Day-Ahead Energy Market and the balancing energy market in each control zone. The last column shows the difference between the total ARR and FTR hedge and the congestion cost for each control zone.

The results indicate that the value of ARRs and FTRs together were less than total congestion costs by about $52.2 million. During the 2007 to 2008 planning period, the 107,992 MW of cleared ARRs produced $1,640.5 million of ARR credits while the total of all FTR credits was $2,038.9 million. Together, the ARR credits and FTR credits provided approximately $3,679.4 million in total ARR and FTR revenue. When calculating the total ARR and FTR hedge, the cost to obtain the FTRs must be subtracted from the total ARR and FTR revenue. This cost is the total sum of the FTR auction revenues which was $1,736.1 million for the 2007 to 2008 planning period. The total ARR and FTR hedge equals $1,943.2 million, a hedge of 97.4 percent of $1,995.5 million of congestion in the Day-Ahead Energy Market and the balancing energy market. For example, the table shows that all ARRs and FTRs that sink in the AP Control Zone received $585.1 million in ARR credits and $592.5 million in FTR credits. After subtracting the cost of the FTRs, the FTR auction revenue of $491.8 million, the total ARR and FTR hedge was $685.9 million. Their total hedge was $223.5 million higher than the $462.4 million of congestion in the Day-Ahead Energy Market and the balancing energy market.

Table 8-27 ARR and FTR congestion hedging by control zone: Planning period 2007 to 2008

Control Zone	ARR Credits	FTR Credits	FTR Auction Revenue	Total ARR and FTR Hedge	Congestion	Total Hedge - Congestion Difference	Percent Hedged
AECO	$30,399,517	$33,818,154	$26,487,534	$37,730,137	$48,611,136	($10,880,999)	77.6%
AEP	$235,192,904	$74,060,394	$122,461,520	$186,791,778	$224,108,931	($37,317,153)	83.3%
AP	$585,103,411	$592,512,119	$491,764,536	$685,850,994	$462,376,328	$223,474,666	>100%
BGE	$75,854,553	$63,409,285	$63,365,238	$75,898,600	$74,161,439	$1,737,161	>100%
ComEd	$22,605,389	($64,942,926)	($30,250,928)	($12,086,609)	$215,858,584	($227,945,193)	<0%
DAY	$10,283,638	($35,353,881)	($25,729,852)	$659,609	$17,884,456	($17,224,847)	3.7%
DLCO	$1,861,518	($24,829,264)	($27,921,904)	$4,954,158	$11,410,848	($6,456,690)	43.4%
Dominion	$184,589,565	$253,021,344	$196,207,169	$241,403,740	$283,479,504	($42,075,764)	85.2%
DPL	$24,582,545	$27,834,839	$41,345,962	$11,071,422	$56,034,968	($44,963,546)	19.8%
JCPL	$44,530,720	$289,812,635	$87,916,212	$246,427,143	$228,011,843	$18,415,300	>100%
Met-Ed	$40,542,857	$56,186,522	$56,735,375	$39,994,004	$52,663,379	($12,669,375)	75.9%
PECO	$89,541,114	$42,270,945	$94,973,373	$36,838,686	($55,027,453)	$91,866,139	>100%
PENELEC	$35,825,762	$242,914,519	$139,361,603	$139,378,678	$186,535,306	($47,156,628)	74.7%
Pepco	$45,765,395	$266,025,285	$218,553,668	$93,237,012	$177,145,206	($83,908,194)	52.6%
PJM	$15,188,162	$13,724,519	$13,853,916	$15,058,765	($85,980,478)	$101,039,243	>100%
PPL	$53,816,218	$53,460,555	$57,050,864	$50,225,909	($14,546,632)	$64,772,541	>100%
PSEG	$142,818,598	$148,445,275	$206,565,360	$84,698,513	$102,416,667	($17,718,154)	82.7%
RECO	$1,951,540	$6,541,812	$3,398,262	$5,095,090	$10,333,202	($5,238,112)	49.3%
Total	$1,640,453,406	$2,038,912,131	$1,736,137,908	$1,943,227,629	$1,995,477,234	($52,249,605)	97.4%

Table 8-28 shows that for the 2007 to 2008 planning period, the total ARR and FTR hedge was $52.2 million less than the total congestion within PJM. All ARRs and FTRs hedged approximately 97.4 percent of the total congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM. For the first seven months of the 2008 to 2009 planning period, the FTR payout ratio was 99.6 percent of the target allocation. All ARRs and FTRs hedged 97.2 percent of the total congestion costs within PJM for the first seven months of the 2008 to 2009 planning period. The total ARR and FTR hedge position was less than the cost of congestion by $37.6 million.

Table 8-28 ARR and FTR congestion hedging: Planning periods 2007 to 2008 and 2008 to 2009[54]

Planning Period	ARR Credits	FTR Credits	FTR Auction Revenue	Total ARR and FTR Hedge	Congestion	Total Hedge - Congestion Difference	Percent Hedged
2007/2008	$1,640,453,406	$2,038,912,131	$1,736,137,908	$1,943,227,629	$1,995,477,234	($52,249,605)	97.4%
2008/2009*	$1,384,429,209	$1,358,489,527	$1,458,303,545	$1,284,615,190	$1,322,177,077	($37,561,887)	97.2%

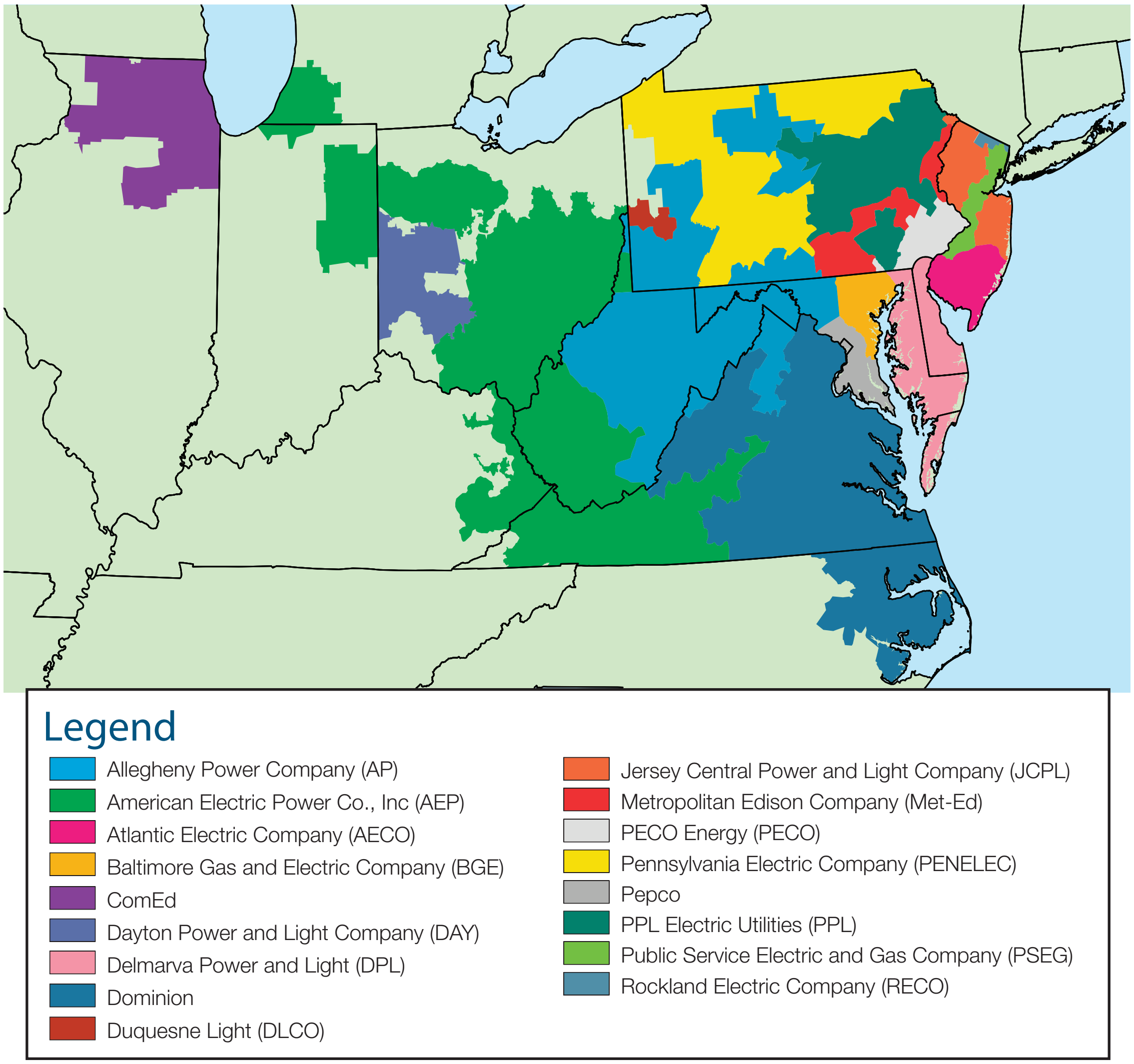
* Shows seven months ended 31-Dec-08

54 The FTR credits do not include after-the-fact adjustments. For the 2008 to 2009 planning period, the ARR credits were the total credits allocated to all ARR holders for the first seven months (June through December 2008) of this planning period, and the FTR Auction Revenue includes the net revenue in the Monthly Balance of Planning Period FTR Auctions for the first seven months of this planning period and the portion of Annual FTR Auction revenue distributed to the first seven months.

APPENDIX A – PJM GEOGRAPHY

During 2008, the PJM geographic footprint encompassed 17 control zones located in Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

Figure A-1 PJM's footprint and its 17 control zones



Analysis of 2008 market results requires comparison to 2007 and certain other prior years. During 2006, 2007 and 2008 the PJM footprint was stable. During calendar years 2004 and 2005, however, PJM integrated five new control zones, three in 2004 and two in 2005. When making comparisons involving this period, the 2004, 2005 and 2006 state of the market reports referenced phases, each corresponding to market integration dates:[1]

1 See the *2004 State of the Market Report* (March 8, 2005) for more detailed descriptions of Phases 1, 2 and 3 and the *2005 State of the Market Report* (March 8, 2006) for more detailed descriptions of Phases 4 and 5.

  www.monitoringanalytics.com

- **Phase 1 (2004).** The four-month period from January 1, through April 30, 2004, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones,[2] and the Allegheny Power Company (AP) Control Zone.[3]

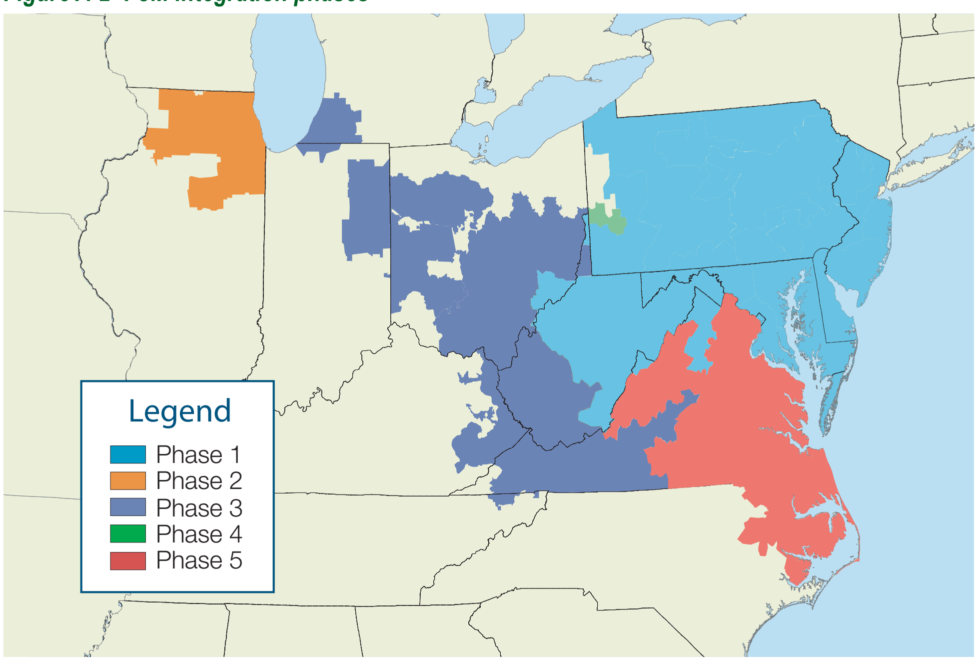
- **Phase 2 (2004).** The five-month period from May 1, through September 30, 2004, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones, the AP Control Zone and the ComEd Control Area.[4]

- **Phase 3 (2004).** The three-month period from October 1, through December 31, 2004, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones, the AP Control Zone and the ComEd Control Zone plus the American Electric Power Control Zone (AEP) and The Dayton Power & Light Company Control Zone (DAY). The ComEd Control Area became the ComEd Control Zone on October 1.

- **Phase 4 (2005).** The four-month period from January 1, through April 30, 2005, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones, the AP Control Zone, the ComEd Control Zone, the AEP Control Zone and the DAY Control Zone plus the Duquesne Light Company (DLCO) Control Zone which was integrated into PJM on January 1, 2005.

- **Phase 5 (2005).** The eight-month period from May 1, through December 31, 2005, during which PJM was comprised of the Phase 4 elements plus the Dominion Control Zone which was integrated into PJM on May 1, 2005.

Figure A-2 PJM integration phases



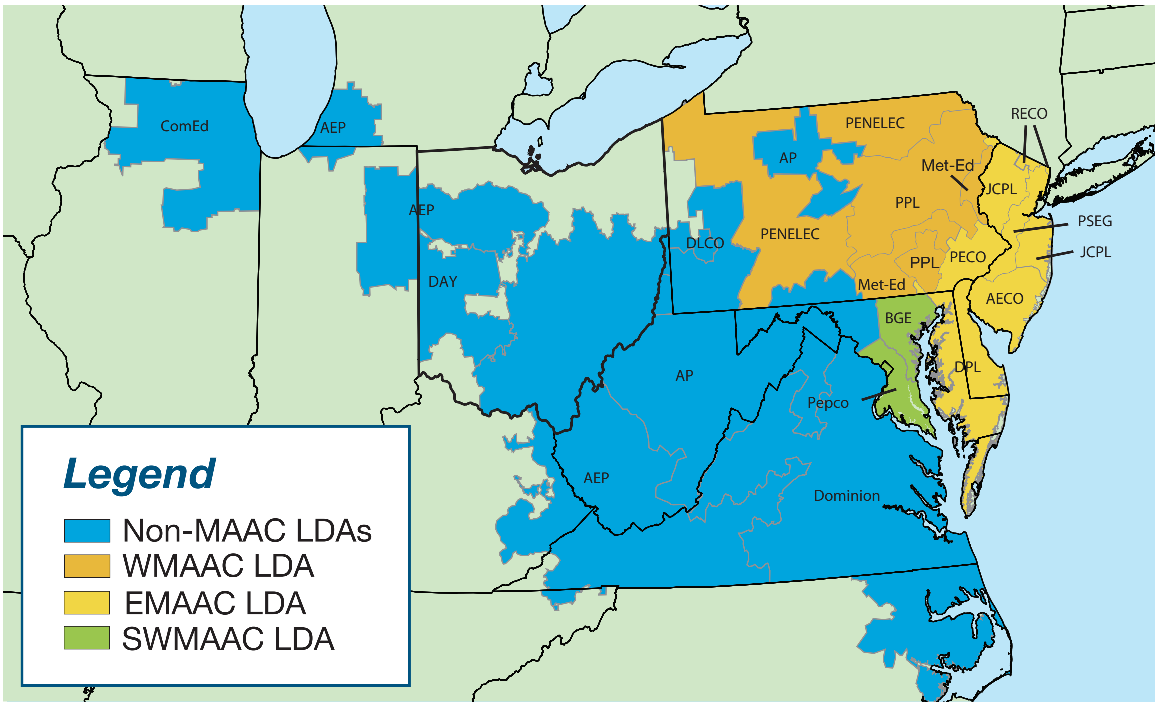
2 The Mid-Atlantic Region is comprised of the AECO, BGE, DPL, JCPL, Met-Ed, PECO, PENELEC, Pepco, PPL, PSEG and RECO control zones.

3 Zones, control zones and control areas are geographic areas that customarily bear the name of a large utility service provider operating within their boundaries. Names apply to the geographic area, not to any single company. The geographic areas did not change with the formalization of these concepts during PJM integrations. For simplicity, zones are referred to as control zones for all phases. The only exception is ComEd which is called the ComEd Control Area for Phase 2 only.

4 During the five-month period May 1, through September 30, 2004, the ComEd Control Zone (ComEd) was called the Northern Illinois Control Area (NICA).

A locational deliverability area (LDA) is a geographic area within PJM that has limited transmission capability to import capacity in the RPM design to satisfy its reliability requirements, as determined by PJM in connection with the preparation of the Regional Transmission Expansion Plan (RTEP) and as specified in Schedule 10.1 of the PJM "Reliability Assurance Agreement with Load-Serving Entities."[5]

Figure A-3 PJM locational deliverability areas

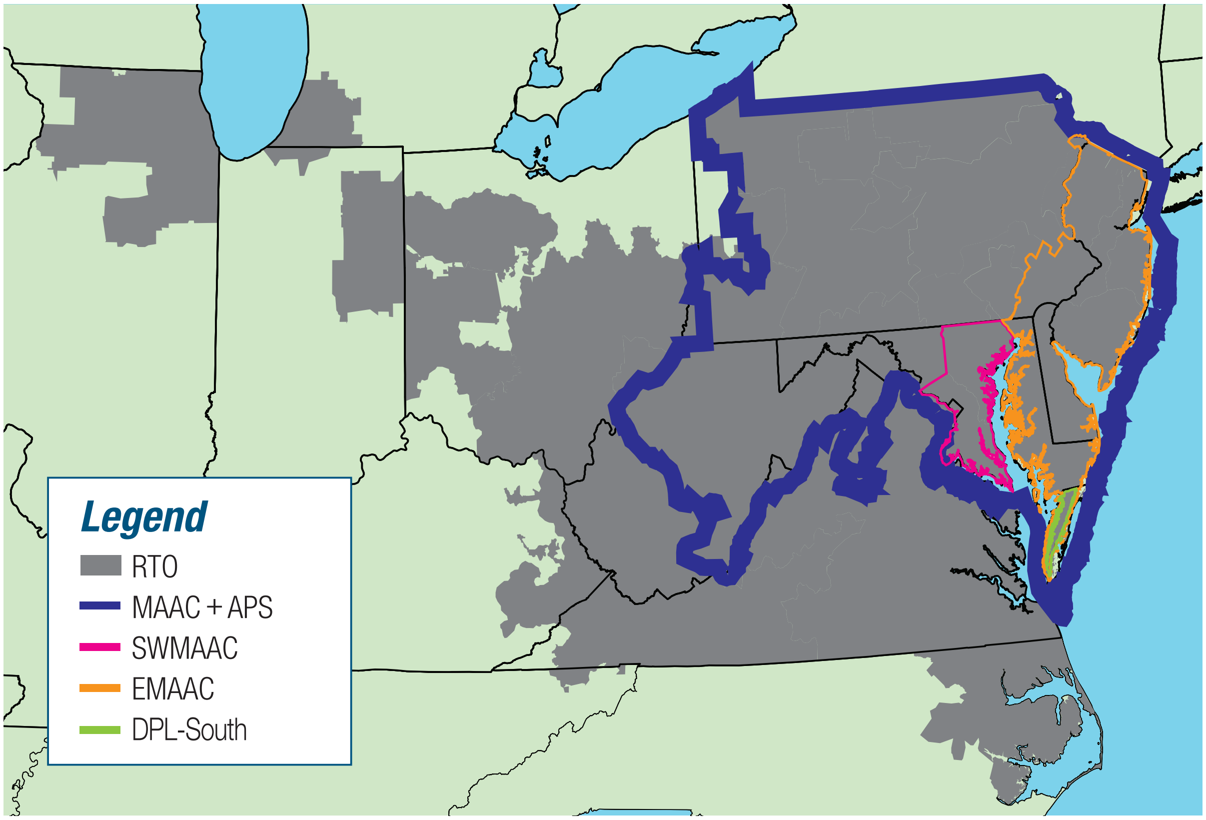


In PJM's Reliability Pricing Model (RPM) Auctions, markets are defined dynamically by LDA. The regional transmission organization (RTO) market comprises the entire PJM footprint, unless an LDA is constrained. Each constrained LDA or group of LDAs is a separate market with a separate clearing price and the RTO market is the balance of the footprint.

For the 2007/2008 and 2008/2009 base residual auctions, the defined markets were RTO, EMAAC and SWMAAC. For the 2009/2010 base residual auction, the defined markets were RTO, MAAC+APS (Allegheny Power System) and SWMAAC. For the 2010/2011 base residual auction, the defined markets were RTO and DPL-South, and for the 2011/2012 base residual auction, the only defined market was RTO. These RPM auction markets are shown in Figure A-4.

5 See PJM. "Open Access Transmission Tariff (OATT)," "Attachment DD: Definition 2.38" (Issued September 29, 2006, with an effective date of June 20, 2007).

Figure A-4 PJM RPM locational deliverability area markets



APPENDIX B – PJM MARKET MILESTONES

Year	Month	Event
1996	April	FERC Order 888, "Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities"
1997	April	Energy Market with cost-based offers and market-clearing prices
	November	FERC approval of ISO status for PJM
1998	April	Cost-based Energy LMP Market
1999	January	Daily Capacity Market
	March	FERC approval of market-based rates for PJM
	March	Monthly and Multimonthly Capacity Market
	March	FERC approval of Market Monitoring Plan
	April	Offer-based Energy LMP Market
	April	FTR Market
2000	June	Regulation Market
	June	Day-Ahead Energy Market
	July	Customer Load-Reduction Pilot Program
2001	June	PJM Emergency and Economic Load-Response Programs
2002	April	Integration of AP Control Zone into PJM Western Region
	June	PJM Emergency and Economic Load-Response Programs
	December	Spinning Reserve Market
	December	FERC approval of RTO status for PJM
2003	May	Annual FTR Auction
2004	May	Integration of ComEd Control Area into PJM
	October	Integration of AEP Control Zone into PJM Western Region
	October	Integration of DAY Control Zone into PJM Western Region
2005	January	Integration of DLCO Control Zone into PJM
	May	Integration of Dominion Control Zone into PJM
2006	May	Balance of Planning Period FTR Auction
2007	April	First RPM Auction
	June	Marginal loss component in LMPs
2008	June	Day Ahead Scheduling Reserve (DASR) Market
	August	Independent, External MMU created as Monitoring Analytics, LLC
	October	Long Term FTR Auction
	December	Modified Operating Reserve Accounting Rules
	December	Three Pivotal Supplier Test in Regulation Market

APPENDIX C – ENERGY MARKET

This appendix provides more detailed information about load, locational marginal prices (LMP) and offer-capped units.

Load

Frequency Distribution of Load

Table C-1 provides the frequency distributions of PJM load by hour, for the calendar years 2004 to 2008.[1] The table shows the number of hours (frequency) and the cumulative percent of hours (cumulative percent) when the load was between 0 GWh and 20 GWh and then within a given 5-GWh load interval, or for the cumulative column, within the interval plus all the lower load intervals. The integrations of the AP Control Zone during 2002, the ComEd, AEP and DAY control zones during 2004 and the DLCO and Dominion control zones during 2005 mean that annual comparisons of load frequency are significantly affected by PJM's geographic growth.[2]

The frequency distribution of load in 2004 reflects the integrations of the ComEd, AEP and DAY control zones. The most frequently occurring load interval was 35 GWh to 40 GWh at 15.8 percent of the hours. The next most frequently occurring interval was 40 GWh to 45 GWh at 14.9 percent of the hours. Load was less than 60 GWh for 74.8 percent of the time, less than 70 GWh for 92.8 percent of the time and less than 90 GWh for all but nine hours.

The frequency distribution of load in 2005 reflects the phased integrations of the DLCO and Dominion control zones. The most frequently occurring load interval was 75 GWh to 80 GWh at 16.1 percent of the hours. The next most frequently occurring interval was 65 GWh to 70 GWh at 13.4 percent of the hours. Load was less than 85 GWh for 72.9 percent of the time, less than 100 GWh for 88.2 percent of the time and less than 130 GWh for all but 22 hours.

For the year 2006, the most frequently occurring load interval was 75 GWh to 80 GWh at 17.1 percent of the hours. The next most frequently occurring interval was 80 GWh to 85 GWh at 15.3 percent of the hours. Load was less than 85 GWh for 70.9 percent of the hours, less than 100 GWh for 91.5 percent of the hours and less than 130 GWh for all but 50 hours.

During 2007, the most frequently occurring load interval was 80 GWh to 85 GWh at 15.3 percent of the hours. The next most frequently occurring interval was 75 GWh to 80 GWh at 14.0 percent of the hours. Load was less than 85 GWh for 62.6 percent of the hours, less than 100 GWh for 88.8 percent of the hours and less than 130 GWh for all but 15 hours.

During 2008, the most frequently occurring load interval was 75 GWh to 80 GWh at 17.5 percent of the hours. The next most frequently occurring interval was 80 GWh to 85 GWh at 13.8 percent of the hours. Load was less than 85 GWh for 68.8 percent of the hours, less than 100 GWh for 91.9

1 The definitions of load are discussed in the *2008 State of the Market Report*, Volume II, Appendix I, "Load Definitions."
2 See the *2008 State of the Market Report*, Volume II, Appendix A, "PJM Geography."

percent of the hours and less than 130 GWh for all hours.The peak demand for 2008 was 130,100 MW on June 9, 2008. It was 6.7 percent lower than the 2007 peak demand of 139,428 MW on August 8, 2007.[3]

Table C-1 Frequency distribution of PJM real-time, hourly load: Calendar years 2004 to 2008

	2004		2005		2006		2007		2008	
Load (GWh)	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
0 to 20	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
20 to 25	15	0.17%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
25 to 30	280	3.36%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
30 to 35	697	11.29%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
35 to 40	1,387	27.08%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
40 to 45	1,311	42.01%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
45 to 50	1,150	55.10%	71	0.81%	2	0.02%	0	0.00%	0	0.00%
50 to 55	847	64.74%	286	4.08%	129	1.50%	79	0.90%	127	1.45%
55 to 60	885	74.82%	636	11.34%	504	7.25%	433	5.84%	517	7.33%
60 to 65	760	83.47%	843	20.96%	689	15.11%	637	13.12%	667	14.92%
65 to 70	821	92.82%	1,170	34.32%	967	26.15%	890	23.28%	941	25.64%
70 to 75	391	97.27%	1,089	46.75%	1,079	38.47%	878	33.30%	1,048	37.57%
75 to 80	157	99.06%	1,407	62.81%	1,501	55.61%	1,227	47.31%	1,535	55.04%
80 to 85	48	99.60%	887	72.93%	1,337	70.87%	1,338	62.58%	1,208	68.80%
85 to 90	26	99.90%	557	79.29%	943	81.63%	981	73.78%	916	79.22%
90 to 95	7	99.98%	453	84.46%	569	88.13%	741	82.24%	655	86.68%
95 to 100	2	100.00%	330	88.23%	295	91.50%	577	88.82%	457	91.88%
100 to 105	0	0.00%	308	91.75%	215	93.95%	382	93.18%	292	95.21%
105 to 110	0	0.00%	283	94.98%	161	95.79%	223	95.73%	181	97.27%
110 to 115	0	0.00%	169	96.91%	145	97.44%	179	97.77%	133	98.78%
115 to 120	0	0.00%	113	98.20%	102	98.61%	106	98.98%	58	99.44%
120 to 125	0	0.00%	93	99.26%	45	99.12%	43	99.47%	35	99.84%
125 to 130	0	0.00%	43	99.75%	27	99.43%	31	99.83%	14	100.00%
130 to 135	0	0.00%	22	100.00%	19	99.65%	12	99.97%	0	0.00%
135 to 140	0	0.00%	0	0.00%	19	99.86%	3	100.00%	0	0.00%
> 140	0	0.00%	0	0.00%	12	100.00%	0	0.00%	0	0.00%

Off-Peak and On-Peak Load

Table C-2 presents summary load statistics for 1998 to 2008 for the off-peak and on-peak hours, while Table C-3 shows the percent change in load on a year-to-year basis. The on-peak period is defined for each weekday (Monday to Friday) as the hour ending 0800 to the hour ending 2300

3 Peak loads shown are eMTR load. See the *2008 State of the Market Report*, Volume II, Appendix I, "Load Definitions," for detailed definitions of load.

Eastern Prevailing Time (EPT), excluding North American Electric Reliability Council (NERC) holidays. Table C-2 shows that on-peak load was 21.8 percent higher than off-peak load in 2008. Average load during on-peak hours in 2008 was 3.5 percent lower than in 2007. Off-peak load in 2008 was 1.8 percent lower than in 2007.[4](See Table C-3.)

Table C-2 Real time Off-peak and on-peak load (MW): Calendar years 1998 to 2008

	Average			Median			Standard Deviation		
	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak
1998	25,269	32,344	1.28	24,729	31,081	1.26	4,091	4,388	1.07
1999	26,454	33,269	1.26	25,780	31,950	1.24	4,947	4,824	0.98
2000	26,917	33,797	1.26	26,313	32,757	1.24	4,466	4,181	0.94
2001	26,804	34,303	1.28	26,433	33,076	1.25	4,225	4,851	1.15
2002	31,734	40,314	1.27	30,590	38,365	1.25	6,111	7,464	1.22
2003	33,598	41,755	1.24	32,973	40,802	1.24	5,545	5,424	0.98
2004	44,631	56,020	1.26	43,028	56,578	1.31	10,845	12,595	1.16
2005	70,291	87,164	1.24	68,049	82,503	1.21	12,733	15,236	1.20
2006	71,810	88,323	1.23	70,300	84,810	1.21	11,348	12,662	1.12
2007	73,499	91,066	1.24	71,751	88,494	1.23	11,501	11,926	1.04
2008	72,175	87,915	1.22	70,516	85,431	1.21	11,378	11,205	0.98

Table C-3 Multiyear change in real time load: Calendar years 1998 to 2008

	Average			Median			Standard Deviation		
	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak
1998	NA	NA	NA	NA	NA	NA	NA	NA	NA
1999	4.7%	2.9%	(1.6%)	4.3%	2.8%	(1.6%)	20.9%	9.9%	(8.4%)
2000	1.8%	1.6%	0.0%	2.1%	2.5%	0.0%	(9.7%)	(13.3%)	(4.1%)
2001	(0.4%)	1.5%	1.6%	0.5%	1.0%	0.8%	(5.4%)	16.0%	22.3%
2002	18.4%	17.5%	(0.8%)	15.7%	16.0%	0.0%	44.6%	53.9%	6.1%
2003	5.9%	3.6%	(2.4%)	7.8%	6.4%	(0.8%)	(9.3%)	(27.3%)	(19.7%)
2004	32.8%	34.2%	1.6%	30.5%	38.7%	5.6%	95.6%	132.2%	18.4%
2005	57.5%	55.6%	(1.6%)	58.2%	45.8%	(7.6%)	17.4%	21.0%	3.4%
2006	2.2%	1.3%	(0.8%)	3.3%	2.8%	0.0%	(10.9%)	(16.9%)	(6.7%)
2007	2.4%	3.1%	0.8%	2.1%	4.3%	1.7%	1.3%	(5.8%)	(7.1%)
2008	(1.8%)	(3.5%)	(1.6%)	(1.7%)	(3.5%)	(1.6%)	(1.1%)	(6.0%)	(5.8%)

4 The increase in on-peak median load for 2006 was incorrectly reported as 3.2 percent in the *2006 State of the Market Report* rather than the 2.8 percent shown here.

Locational Marginal Price (LMP)

In assessing changes in LMP over time, the Market Monitoring Unit (MMU) examines three measures: simple LMP, load-weighted LMP and fuel-cost-adjusted, load-weighted LMP. Simple LMP measures the change in reported price. Load-weighted LMP measures the change in reported price weighted by the actual hourly MWh load to reflect what customers actually pay for energy. Fuel-cost-adjusted, load-weighted LMP measures the change in reported price actually paid by load after accounting for the change in price that reflects shifts in underlying fuel prices.[5]

Real-Time LMP

Frequency Distribution of Real-Time LMP

Table C-4 provides frequency distributions of PJM real-time hourly LMP for the calendar years 2004 to 2008. The table shows the number of hours (frequency) and the cumulative percent of hours (cumulative percent) when the hourly PJM LMP was within a given $10-per-MWh price interval and lower than $300 per MWh, or within a given $100-per-MWh price interval and higher than $300 per MWh, or for the cumulative column, within the interval plus all the lower price intervals.

In 2004, LMP occurred in the $30-per-MWh to $40-per-MWh interval most frequently at 21.9 percent of the time and in the $20-per-MWh to $30-per-MWh interval nearly as frequently at 21.6 percent of the time. In 2005, LMP occurred in the $30-per-MWh to $40-per-MWh interval most frequently at 20.5 percent of the time and in the $20-per-MWh to $30-per-MWh interval at 14.7 percent of the time. In 2005, LMP was less than $60 per MWh for 63.2 percent of the hours, less than $100 per MWh for 87.4 percent of the hours and LMP was $200 per MWh or greater for 35 hours (0.4 percent of the hours). In 2006, LMP was in the $20-per-MWh to $30-per-MWh interval most frequently (22.4 percent of the time) and in the $30-per-MWh to $40-per-MWh interval next most frequently (21.0 percent of the hours). In 2007, LMP was in the $20-per-MWh to $30-per-MWh interval most frequently (17.9 percent of the time) and in the $30-per-MWh to $40-per-MWh interval next most frequently (16.8 percent of the hours). In 2007, LMP was $60 per MWh or less for 60.7 percent of the hours and was $100 per MWh or less for 91.0 percent of the hours. LMP was more than $200 per MWh for 35 hours (0.4 percent of the hours). In 2008, LMP was in the $40-per-MWh to $50-per-MWh interval most frequently (17.5 percent of the time) and in the $30-per-MWh to $40-per-MWh interval next most frequently (16.4 percent of the hours).

5 See the *2008 State of the Market Report*, Volume II, Appendix H, "Calculating Locational Marginal Price."

Table C-4 Frequency distribution by hours of PJM Real-Time Energy Market LMP (Dollars per MWh): Calendar years 2004 to 2008

	2004		2005		2006		2007		2008	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
$10 and less	173	1.97%	142	1.62%	85	0.97%	56	0.64%	94	1.07%
$10 to $20	712	10.08%	259	4.58%	247	3.79%	185	2.75%	129	2.54%
$20 to $30	1,900	31.71%	1,290	19.30%	1,958	26.14%	1,571	20.68%	490	8.12%
$30 to $40	1,928	53.65%	1,793	39.77%	1,840	47.15%	1,470	37.47%	1,443	24.54%
$40 to $50	1,445	70.10%	1,172	53.15%	1,405	63.18%	1,108	50.11%	1,533	42.00%
$50 to $60	994	81.42%	877	63.16%	1,040	75.06%	931	60.74%	1,212	55.79%
$60 to $70	668	89.03%	730	71.50%	662	82.61%	827	70.18%	845	65.41%
$70 to $80	445	94.09%	568	77.98%	479	88.08%	726	78.47%	709	73.49%
$80 to $90	270	97.17%	453	83.15%	347	92.04%	646	85.84%	502	79.20%
$90 to $100	117	98.50%	374	87.42%	230	94.67%	451	90.99%	385	83.58%
$100 to $110	72	99.32%	297	90.81%	162	96.52%	240	93.73%	352	87.59%
$110 to $120	25	99.60%	208	93.18%	95	97.60%	178	95.76%	265	90.61%
$120 to $130	14	99.76%	159	95.00%	61	98.30%	110	97.02%	199	92.87%
$130 to $140	10	99.87%	110	96.26%	46	98.82%	76	97.89%	144	94.51%
$140 to $150	6	99.94%	94	97.33%	27	99.13%	53	98.49%	111	95.78%
$150 to $160	3	99.98%	53	97.93%	16	99.32%	26	98.79%	102	96.94%
$160 to $170	1	99.99%	57	98.58%	11	99.44%	29	99.12%	68	97.71%
$170 to $180	0	99.99%	51	99.17%	6	99.51%	18	99.33%	52	98.30%
$180 to $190	1	100.00%	22	99.42%	3	99.54%	9	99.43%	45	98.82%
$190 to $200	0	0.00%	16	99.60%	5	99.60%	15	99.60%	29	99.15%
$200 to $210	0	0.00%	12	99.74%	3	99.63%	6	99.67%	20	99.37%
$210 to $220	0	0.00%	10	99.85%	7	99.71%	4	99.71%	11	99.50%
$220 to $230	0	0.00%	5	99.91%	1	99.73%	4	99.76%	14	99.66%
$230 to $240	0	0.00%	1	99.92%	1	99.74%	2	99.78%	10	99.77%
$240 to $250	0	0.00%	1	99.93%	1	99.75%	5	99.84%	2	99.80%
$250 to $260	0	0.00%	3	99.97%	1	99.76%	2	99.86%	5	99.85%
$260 to $270	0	0.00%	2	99.99%	0	99.76%	4	99.91%	4	99.90%
$270 to $280	0	0.00%	0	99.99%	3	99.79%	0	99.91%	1	99.91%
$280 to $290	0	0.00%	1	100.00%	1	99.81%	0	99.91%	1	99.92%
$290 to $300	0	0.00%	0	0.00%	0	99.81%	0	99.91%	0	99.92%
$300 to $400	0	0.00%	0	0.00%	11	99.93%	2	99.93%	6	99.99%
$400 to $500	0	0.00%	0	0.00%	2	99.95%	4	99.98%	1	100.00%
$500 to $600	0	0.00%	0	0.00%	1	99.97%	1	99.99%	0	0.00%
$600 to $700	0	0.00%	0	0.00%	1	99.98%	1	100.00%	0	0.00%
> $700	0	0.00%	0	0.00%	2	100.00%	0	0.00%	0	0.00%

Off-Peak and On-Peak, PJM Real-Time, Load-Weighted LMP: 2007 to 2008

Table C-5 shows load-weighted, average LMP for 2007 and 2008 during off-peak and on-peak periods. In 2008, the on-peak, load-weighted LMP was 45.8 percent higher than the off-peak LMP, while in 2007, it was 52.6 percent higher. On-peak, load-weighted, average LMP in 2008 was 13.5 percent higher than in 2007. Off-peak, load-weighted LMP in 2008 was 18.8 percent higher than in 2007. The on-peak median LMP was higher in 2008 than in 2007 by 7.7 percent; off-peak median LMP was higher in 2008 than in 2007 by 19.9 percent. Dispersion in load-weighted LMP, as indicated by standard deviation, was 25.5 percent higher in 2008 than in 2007 during off-peak hours and was 4.2 percent higher during on-peak hours. Since the mean was above the median during on-peak and off-peak hours, both showed a positive skewness. The mean was, however, proportionately higher than the median in 2008 as compared to 2007 during on-peak periods (14.2 percent in 2008 compared to 8.3 percent in 2007). The differences reflect larger positive skewness in the on-peak hours.

Table C-5 Off-peak and on-peak, PJM load-weighted, average LMP (Dollars per MWh): Calendar years 2007 to 2008

	2007			2008			Difference 2007 to 2008		
	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak
Average	$48.43	$73.91	1.53	$57.55	$83.90	1.46	18.8%	13.5%	(4.6%)
Median	$37.89	$68.23	1.80	$45.43	$73.47	1.62	19.9%	7.7%	(10.0%)
Standard deviation	$29.20	$39.07	1.34	$36.64	$40.72	1.11	25.5%	4.2%	(17.2%)

PJM Real-Time, Load-Weighted LMP during Constrained Hours

Table C-6 shows that the PJM load-weighted, average LMP during constrained hours was 12.0 percent higher in 2008 than it had been in 2007.[6] The load-weighted, median LMP during constrained hours was 4.4 percent higher in 2008 than in 2007 and the standard deviation was 9.2 percent higher in 2008 than in 2007.

Table C-6 PJM load-weighted, average LMP during constrained hours (Dollars per MWh): Calendar years 2007 to 2008

	2007	2008	Difference
Average	$64.54	$72.28	12.0%
Median	$57.49	$60.00	4.4%
Standard deviation	$38.09	$41.58	9.2%

Table C-7 provides a comparison of PJM load-weighted, average LMP during constrained and unconstrained hours for 2007 and 2008. In 2008, load-weighted, average LMP during constrained

6 A constrained hour, or a constraint hour, is any hour during which one or more facilities are congested. Since the *2006 State of the Market Report,* in order to have a consistent metric for real-time and day-ahead congestion frequency, real-time congestion frequency has been measured using the convention that an hour is constrained if any of its component five-minute intervals is constrained. This is also consistent with the way in which PJM reports real-time congestion. In the *2005 State of the Market Report*, an hour was considered constrained if one or more facilities were constrained for four or more of the 12 five-minute intervals in that hour. In the *2004 State of the Market Report*, this appendix defined a congested hour as one in which the difference in LMP between at least two buses in that hour was greater than $1.00.

hours was 11.3 percent higher than load-weighted, average LMP during unconstrained hours. The comparable number for 2007 was 35.0 percent.

Table C-7 PJM load-weighted, average LMP during constrained and unconstrained hours (Dollars per MWh): Calendar years 2007 to 2008

	2007			2008		
	Unconstrained Hours	Constrained Hours	Difference	Unconstrained Hours	Constrained Hours	Difference
Average	$47.82	$64.54	35.0%	$64.94	$72.28	11.3%
Median	$40.15	$57.49	43.2%	$56.52	$60.00	6.2%
Standard deviation	$26.78	$38.09	42.2%	$36.89	$41.58	12.7%

Table C-8 shows the number of hours and the number of constrained hours during each month in 2007 and 2008. There were 7,408 constrained hours in 2008 and 7,161 in 2007, an increase of approximately 3.4 percent. Table C-10 also shows that the average number of constrained hours per month was slightly higher in 2008 than in 2007, with 617 per month in 2008 versus 597 per month in 2007.

Table C-8 Table 0-10 PJM real-time constrained hours: Calendar years 2007 to 2008

	2007 Constrained Hours	2008 Constrained Hours	Total Hours
Jan	497	638	744
Feb	521	507	672
Mar	629	560	743
Apr	466	671	720
May	558	638	744
Jun	642	697	720
Jul	657	513	744
Aug	663	648	744
Sep	627	673	720
Oct	615	718	744
Nov	585	591	721
Dec	701	554	744
Avg	597	617	730

Day-Ahead and Real-Time LMP

On average, prices in the Real-Time Energy Market in 2008 were higher than those in the Day-Ahead Energy Market and real-time prices showed greater dispersion. This pattern of system average LMP distribution for 2008 can be seen by comparing Table C-4 and Table C-9. Table C-9 shows frequency distributions of PJM day-ahead hourly LMP for the calendar years 2004 to 2008. Together the tables show the frequency distribution by hours for the two markets. In PJM's Real-Time Energy Market and in the PJM Day-Ahead Energy Market, the most frequently occurring price interval was the $40-per-MWh to $50-per-MWh interval with 17.5 and 17.6 percent of the hours in 2008. The standard deviation of the simple average real-time LMP is higher than that of simple average day-ahead LMP ($38.62 and $30.87 respectively) and the standard deviation of the load-weighted real-time LMP is higher than that of load-weighted day-ahead LMP ($40.97 and $33.14 respectively). In the Real-Time Energy Market, prices were above $200 per MWh for 75 hours (0.9 percent of the hours), reaching a high for the year of $483.27 per MWh on June 12, 2008, during the hour ending 1600 EPT. In the Day-Ahead Energy Market, prices were above $200 per MWh for 36 hours (0.4 percent of the hours) and reached a high for the year of $312.12 per MWh on June 9, 2008, during the hour ending 1600 EPT.

Table C-9 Frequency distribution by hours of PJM Day-Ahead Energy Market LMP (Dollars per MWh): Calendar years 2004 to 2008

	2004		2005		2006		2007		2008	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
$10 and less	59	0.67%	47	0.54%	11	0.13%	3	0.03%	0	0.00%
$10 to $20	715	8.81%	162	2.39%	147	1.80%	88	1.04%	19	0.22%
$20 to $30	1,684	27.98%	1,022	14.05%	1,610	20.18%	1,291	15.78%	320	3.86%
$30 to $40	1,848	49.02%	1,753	34.06%	1,747	40.13%	1,495	32.84%	1,148	16.93%
$40 to $50	1,946	71.17%	1,382	49.84%	1,890	61.70%	1,221	46.78%	1,546	34.53%
$50 to $60	1,357	86.62%	1,102	62.42%	1,364	77.27%	1,266	61.23%	1,491	51.50%
$60 to $70	728	94.91%	812	71.69%	905	87.60%	1,301	76.08%	1,107	64.11%
$70 to $80	278	98.08%	686	79.52%	524	93.58%	939	86.80%	942	74.83%
$80 to $90	110	99.33%	524	85.50%	237	96.29%	504	92.56%	682	82.59%
$90 to $100	42	99.81%	388	89.93%	145	97.95%	264	95.57%	542	88.76%
$100 to $110	11	99.93%	263	92.93%	65	98.69%	155	97.34%	289	92.05%
$110 to $120	4	99.98%	207	95.30%	38	99.12%	104	98.53%	193	94.25%
$120 to $130	2	100.00%	151	97.02%	11	99.25%	59	99.20%	131	95.74%
$130 to $140	0	0.00%	102	98.18%	8	99.34%	33	99.58%	112	97.02%
$140 to $150	0	0.00%	64	98.92%	8	99.43%	13	99.73%	67	97.78%
$150 to $160	0	0.00%	46	99.44%	7	99.51%	8	99.82%	54	98.39%
$160 to $170	0	0.00%	27	99.75%	6	99.58%	7	99.90%	46	98.92%
$170 to $180	0	0.00%	11	99.87%	6	99.65%	3	99.93%	23	99.18%
$180 to $190	0	0.00%	8	99.97%	3	99.68%	4	99.98%	20	99.41%
$190 to $200	0	0.00%	1	99.98%	3	99.71%	1	99.99%	16	99.59%
$200 to $210	0	0.00%	2	100.00%	3	99.75%	1	100.00%	8	99.68%
$210 to $220	0	0.00%	0	0.00%	3	99.78%	0	0.00%	9	99.78%
$220 to $230	0	0.00%	0	0.00%	1	99.79%	0	0.00%	4	99.83%
$230 to $240	0	0.00%	0	0.00%	3	99.83%	0	0.00%	3	99.86%
$240 to $250	0	0.00%	0	0.00%	2	99.85%	0	0.00%	2	99.89%
$250 to $260	0	0.00%	0	0.00%	1	99.86%	0	0.00%	0	99.89%
$260 to $270	0	0.00%	0	0.00%	2	99.89%	0	0.00%	4	99.93%
$270 to $280	0	0.00%	0	0.00%	1	99.90%	0	0.00%	0	99.93%
$280 to $290	0	0.00%	0	0.00%	1	99.91%	0	0.00%	2	99.95%
$290 to $300	0	0.00%	0	0.00%	1	99.92%	0	0.00%	2	99.98%
>$300	0	0.00%	0	0.00%	7	100.00%	0	0.00%	2	100.00%

Off-Peak and On-Peak, Day-Ahead and Real-Time, Simple Average LMP

Table C-10 shows PJM simple average LMP during off-peak and on-peak periods for the Day-Ahead and Real-Time Energy Markets during calendar year 2008. On-peak, day-ahead and real-time, average LMPs were 52.5 percent and 50.4 percent higher, respectively, than the corresponding off-peak average LMPs. Since the mean was above the median in these markets, both showed a positive skewness. The mean was, however, proportionately higher than the median in the Real-Time Energy Market as compared to the Day-Ahead Energy Market during both on-peak and off-peak periods (14.2 percent and 23.9 percent compared to 9.6 percent and 13.2 percent, respectively). The differences reflect larger positive skewness in the Real-Time Energy Market.

Figure C-1 and Figure C-2 show the difference between real-time and day-ahead LMP during calendar year 2008 during the on-peak and off-peak hours, respectively. The difference between real-time and day-ahead average LMP during on-peak hours was $0.13 per MWh. (Day-ahead LMP was higher than real-time LMP.) During the off-peak hours, the difference between real-time and day-ahead average LMP was $0.65 per MWh. (Day-ahead LMP was lower than real-time LMP.)

Table C-10 Off-peak and on-peak, simple average LMP (Dollars per MWh): Calendar year 2008

	Day Ahead			Real Time			Difference in Real Time Relative to Day Ahead		
	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak
Average	$53.11	$81.00	1.53	$53.76	$80.87	1.50	1.2%	(0.2%)	(2.0%)
Median	$46.92	$73.92	1.58	$43.38	$70.81	1.63	(7.5%)	(4.2%)	3.2%
Standard deviation	$23.38	$31.68	1.36	$34.04	$38.48	1.13	45.6%	21.5%	(16.9%)

Figure C-1 Hourly real-time LMP minus day-ahead LMP (On-peak hours): Calendar year 2008

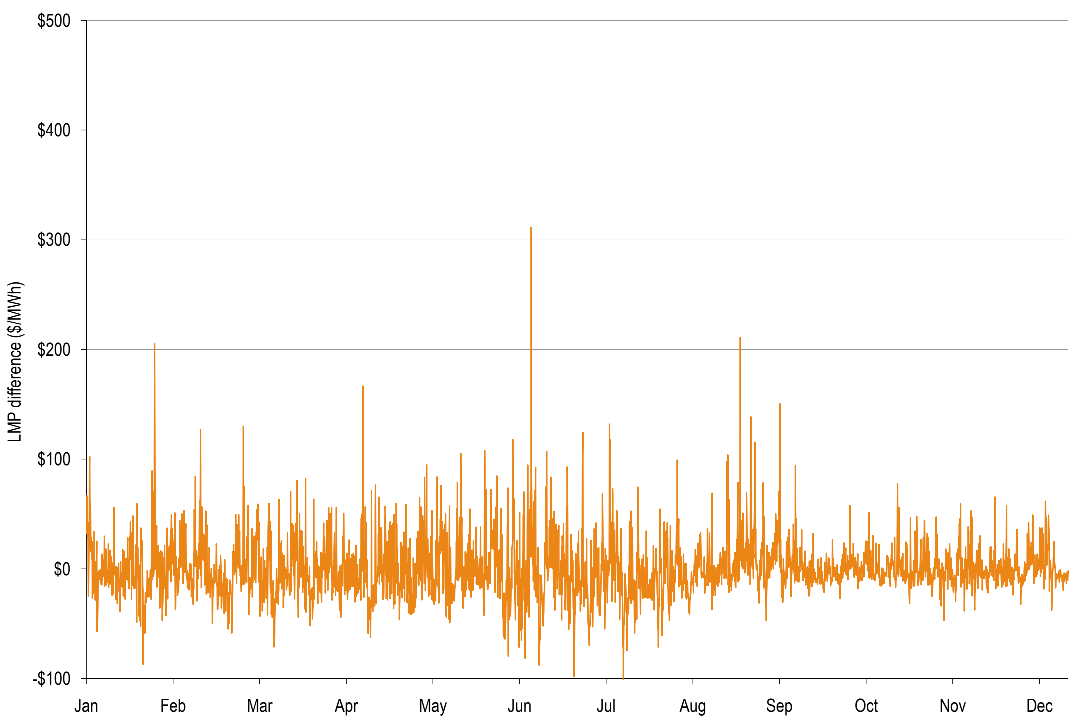
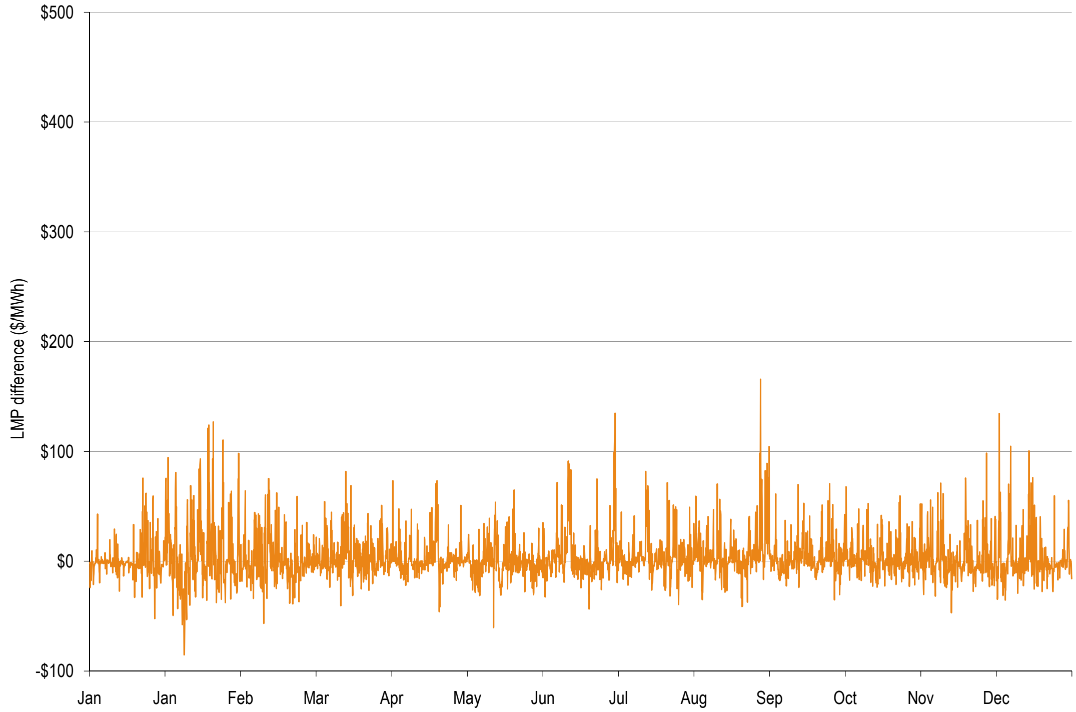


Figure C-2 Hourly real-time LMP minus day-ahead LMP (Off-peak hours): Calendar year 2008



On-Peak and Off-Peak, Zonal, Day-Ahead and Real-Time, Simple Average LMP

Table C-11 and Table C-12 show the on-peak and off-peak, simple average LMPs for each zone in the Day-Ahead and Real-Time Energy Markets during calendar year 2008. The zone with the maximum difference between on-peak real-time and day-ahead LMP was the AECO Control Zone with a real-time, on-peak, zonal LMP that was $2.96 higher than its day-ahead, on-peak, zonal LMP. The DAY Control Zone had the smallest difference with its real-time, on-peak, zonal LMP $0.23 higher than its day-ahead, on-peak, zonal LMP. (See Table C-13.) The DLCO Control Zone had the largest difference between off-peak zonal, real-time and day-ahead LMP, with real-time LMP that was $3.38 lower than day-ahead LMP. The zone with the smallest difference between off-peak, zonal, real-time and day-ahead LMP was the AEP Control Zone with a real-time LMP that was $0.03 higher than day-ahead LMP. (See Table C-14.)

Table C-11 On-peak, zonal, simple average LMP (Dollars per MWh): Calendar year 2008

	Day Ahead	Real Time	Difference	Difference as Percent Real Time
AECO	$95.93	$98.89	$2.96	2.99%
AEP	$68.10	$67.66	($0.44)	(0.65%)
AP	$78.85	$79.25	$0.40	0.50%
BGE	$96.34	$94.12	($2.22)	(2.36%)
ComEd	$66.63	$66.12	($0.51)	(0.77%)
DAY	$68.19	$68.42	$0.23	0.34%
DLCO	$65.22	$64.56	($0.66)	(1.02%)
Dominion	$88.73	$87.38	($1.35)	(1.54%)
DPL	$92.73	$91.37	($1.36)	(1.49%)
JCPL	$96.53	$95.49	($1.04)	(1.09%)
Met-Ed	$90.54	$89.13	($1.41)	(1.58%)
PECO	$90.60	$89.33	($1.27)	(1.42%)
PENELEC	$79.21	$77.21	($2.00)	(2.59%)
Pepco	$96.63	$94.20	($2.43)	(2.58%)
PPL	$89.17	$87.89	($1.28)	(1.46%)
PSEG	$95.83	$94.84	($0.99)	(1.04%)
RECO	$93.84	$92.72	($1.12)	(1.21%)

Table C-12 Off-peak, zonal, simple average LMP (Dollars per MWh): Calendar year 2008

	Day Ahead	Real Time	Difference	Difference as Percent Real Time
AECO	$64.19	$64.81	$0.62	0.96%
AEP	$40.94	$40.97	$0.03	0.07%
AP	$53.06	$54.14	$1.08	1.99%
BGE	$67.04	$67.75	$0.71	1.05%
ComEd	$36.40	$34.75	($1.65)	(4.75%)
DAY	$40.72	$40.81	$0.09	0.22%
DLCO	$38.43	$35.05	($3.38)	(9.64%)
Dominion	$64.13	$65.81	$1.68	2.55%
DPL	$65.03	$64.81	($0.22)	(0.34%)
JCPL	$65.07	$64.22	($0.85)	(1.32%)
Met-Ed	$62.44	$62.10	($0.34)	(0.55%)
PECO	$63.68	$62.61	($1.07)	(1.71%)
PENELEC	$52.79	$51.27	($1.52)	(2.96%)
Pepco	$67.82	$68.43	$0.61	0.89%
PPL	$61.21	$60.64	($0.57)	(0.94%)
PSEG	$65.74	$65.43	($0.31)	(0.47%)
RECO	$64.30	$64.12	($0.18)	(0.28%)

PJM Day-Ahead and Real-Time, Simple Average LMP during Constrained Hours

Table C-13 shows the number of constrained hours for the Day-Ahead and Real-Time Energy Markets and the total number of hours in each month for 2008. Overall, there were 7,408 constrained hours in the Real-Time Energy Market and 8,711 constrained hours in the Day-Ahead Energy Market. Table C-13 shows that in every month of calendar year 2008 the number of constrained hours in the Day-Ahead Energy Market exceeded those in the Real-Time Energy Market. Over the year, the Day-Ahead Energy Market had 17.6 percent more constrained hours than the Real-Time Energy Market.

Table C-13 PJM day-ahead and real-time, market-constrained hours: Calendar year 2008

	DA Constrained Hours	RT Constrained Hours	Total Hours
Jan	744	638	744
Feb	696	507	696
Mar	740	560	743
Apr	696	671	720
May	720	638	744
Jun	720	697	720
Jul	744	513	744
Aug	739	648	744
Sep	720	673	720
Oct	744	718	744
Nov	720	591	721
Dec	728	554	744
Avg	726	617	732

Table C-14 shows PJM simple average LMP during constrained and unconstrained hours in the Day-Ahead and Real-Time Energy Markets. In the Day-Ahead Energy Market, average LMP during constrained hours was 2.2 percent higher than average LMP during unconstrained hours.[7] In the Real-Time Energy Market, average LMP during constrained hours was 11.3 percent higher than average LMP during unconstrained hours. Average LMP during constrained hours was 2.0 percent higher in the Real-Time Energy Market than in the Day-Ahead Energy Market and LMP during unconstrained hours was 6.4 percent lower in the Real-Time Energy Market than in the Day-Ahead Energy Market.

7 This comparison is of limited usefulness as there were only 73 day-ahead unconstrained hours.

Table C-14 PJM simple average LMP during constrained and unconstrained hours (Dollars per MWh): Calendar year 2008

	Day Ahead			Real Time		
	Unconstrained Hours	Constrained Hours	Difference	Unconstrained Hours	Constrained Hours	Difference
Average	$64.72	$66.13	2.2%	$60.61	$67.47	11.3%
Median	$66.37	$58.86	(11.3%)	$52.28	$56.10	7.3%
Standard deviation	$21.50	$30.94	43.9%	$35.72	$39.04	9.3%

Taken together, the data show that average LMP in the Day-Ahead Energy Market during constrained hours was $0.01 (0.0 percent) higher than the overall average LMP for the Day-Ahead Energy Market, while average LMP during unconstrained hours was $1.40 (2.1 percent) lower although these comparisons are of limited usefulness as there were only 73 unconstrained hours in the Day-Ahead Energy Market.[8] In the Real-Time Energy Market, average LMP during constrained hours was $1.07 (1.6 percent) higher than the overall average LMP for the Real-Time Energy Market, while average LMP during unconstrained hours was $5.79 (8.7 percent) lower.

Offer-Capped Units

PJM's market power mitigation goals have focused on market designs that promote competition and that limit market power mitigation to situations where market structure is not competitive and thus where market design alone cannot mitigate market power. In the PJM Energy Market, this situation occurs primarily in the case of local market power. Offer capping occurs only as a result of structurally noncompetitive local markets and noncompetitive offers in the Day-Ahead and Real-Time Energy Markets.

PJM has clear rules limiting the exercise of local market power.[9] The rules provide for offer capping when conditions on the transmission system create a structurally noncompetitive local market, when units in that local market have made noncompetitive offers and when such offers would set the price above the competitive level in the absence of mitigation. Offer caps are set at the level of a competitive offer. Offer-capped units receive the higher of the market price or their offer cap. Thus, if broader market conditions lead to a price greater than the offer cap, the unit receives the higher market price. The rules governing the exercise of local market power recognize that units in certain areas of the system would be in a position to extract monopoly profits, but for these rules.

Under existing rules, PJM suspends offer capping when structural market conditions, as determined by the three pivotal supplier test, indicate that suppliers are reasonably likely to behave in a competitive manner.[10] The goal is to apply a clear rule to limit the exercise of market power by generation owners in load pockets, but to apply the rule in a flexible manner in real time and to lift offer capping when the exercise of market power is unlikely based on the real-time application of the market structure screen.

8 See the *2008 State of the Market Report*, Volume II, Section 2, "Energy Market, Part 1" for a discussion of load and LMP.
9 See PJM. "Amended and Restated Operating Agreement (OA)," Schedule 1, Section 6.4.2 (January 19, 2007).
10 See the *2008 State of the Market Report*, Volume II, Appendix L, "Three Pivotal Supplier Test."

Levels of offer capping have generally been low and stable over the last five years. Table C-15 through Table C-18 show offer capping by month, including the number of offer-capped units and the level of offer-capped MW in the Day-Ahead and Real-Time Energy Markets.[11]

Table C-15 Average day-ahead, offer-capped units: Calendar years 2004 to 2008

	2004		2005		2006		2007		2008	
	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent
Jan	0.4	0.1%	0.4	0.0%	0.1	0.0%	0.2	0.0%	0.5	0.0%
Feb	0.2	0.0%	0.4	0.0%	0.2	0.0%	0.8	0.1%	0.2	0.0%
Mar	0.1	0.0%	0.6	0.1%	0.7	0.1%	0.9	0.1%	0.0	0.0%
Apr	0.3	0.0%	0.4	0.0%	0.2	0.0%	0.2	0.0%	0.2	0.0%
May	0.6	0.1%	0.2	0.0%	0.1	0.0%	0.2	0.0%	0.6	0.1%
Jun	1.1	0.2%	0.4	0.0%	0.7	0.1%	0.8	0.1%	1.5	0.1%
Jul	2.6	0.4%	0.9	0.1%	4.1	0.4%	0.6	0.1%	1.7	0.2%
Aug	3.0	0.4%	1.1	0.1%	4.7	0.5%	1.0	0.1%	0.4	0.0%
Sep	3.0	0.4%	0.2	0.0%	0.6	0.1%	0.2	0.0%	0.4	0.0%
Oct	0.6	0.1%	0.3	0.0%	0.3	0.0%	0.8	0.1%	0.4	0.0%
Nov	0.5	0.1%	0.2	0.0%	0.3	0.0%	0.0	0.0%	0.5	0.1%
Dec	0.5	0.1%	0.7	0.1%	0.5	0.0%	0.1	0.0%	1.3	0.1%

Table C-16 Average day-ahead, offer-capped MW: Calendar years 2004 to 2008

	2004		2005		2006		2007		2008	
	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent
Jan	51	0.1%	87	0.1%	4	0.0%	23	0.0%	16	0.0%
Feb	59	0.1%	75	0.1%	6	0.0%	57	0.1%	11	0.0%
Mar	32	0.1%	57	0.1%	51	0.1%	86	0.1%	2	0.0%
Apr	33	0.1%	34	0.0%	31	0.0%	11	0.0%	31	0.0%
May	52	0.1%	14	0.0%	22	0.0%	38	0.0%	15	0.0%
Jun	49	0.1%	28	0.0%	164	0.2%	28	0.0%	91	0.1%
Jul	243	0.4%	52	0.0%	518	0.5%	45	0.0%	110	0.1%
Aug	346	0.5%	63	0.1%	398	0.4%	58	0.1%	49	0.0%
Sep	218	0.3%	13	0.0%	51	0.1%	14	0.0%	70	0.1%
Oct	34	0.0%	16	0.0%	25	0.0%	77	0.1%	39	0.0%
Nov	28	0.0%	26	0.0%	15	0.0%	4	0.0%	53	0.1%
Dec	35	0.0%	48	0.0%	30	0.0%	4	0.0%	187	0.2%

11 Data quality improvements have caused values in these tables to vary slightly from previously published results.

Table C-17 Average real-time, offer-capped units: Calendar years 2004 to 2008

	2004		2005		2006		2007		2008	
	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent
Jan	2.7	0.4%	2.5	0.3%	1.9	0.2%	1.2	0.1%	3.1	0.3%
Feb	0.7	0.1%	1.3	0.1%	2.1	0.2%	4.2	0.4%	2.6	0.3%
Mar	0.8	0.1%	1.4	0.2%	2.3	0.2%	1.9	0.2%	2.7	0.3%
Apr	1.8	0.3%	1.2	0.1%	1.5	0.2%	1.3	0.1%	3.1	0.3%
May	5.9	0.8%	0.8	0.1%	3.4	0.3%	1.9	0.2%	2.1	0.2%
Jun	3.9	0.5%	10.0	1.0%	2.5	0.3%	6.0	0.6%	8.7	0.8%
Jul	4.7	0.7%	13.9	1.4%	8.6	0.9%	4.4	0.4%	5.7	0.6%
Aug	6.3	0.9%	13.7	1.4%	9.5	1.0%	9.6	0.9%	2.1	0.2%
Sep	4.2	0.6%	7.9	0.8%	1.8	0.2%	5.5	0.5%	4.8	0.5%
Oct	1.1	0.1%	7.9	0.8%	1.7	0.2%	5.0	0.5%	2.5	0.2%
Nov	1.1	0.1%	3.3	0.3%	1.1	0.1%	2.9	0.3%	2.3	0.2%
Dec	3.3	0.4%	4.4	0.4%	1.0	0.0%	4.7	0.5%	2.4	0.2%

Table C-18 Average real-time, offer-capped MW: Calendar years 2004 to 2008

	2004		2005		2006		2007		2008	
	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent
Jan	175	0.4%	209	0.3%	42	0.1%	50	0.1%	99	0.1%
Feb	87	0.2%	145	0.2%	67	0.1%	125	0.1%	92	0.1%
Mar	76	0.2%	74	0.1%	88	0.1%	142	0.2%	117	0.2%
Apr	115	0.3%	59	0.1%	75	0.1%	48	0.1%	125	0.2%
May	257	0.5%	78	0.1%	136	0.2%	68	0.1%	59	0.1%
Jun	167	0.3%	652	0.7%	160	0.2%	190	0.2%	415	0.5%
Jul	332	0.6%	819	0.9%	506	0.5%	160	0.2%	202	0.2%
Aug	450	0.8%	908	1.0%	518	0.6%	314	0.3%	114	0.1%
Sep	268	0.5%	477	0.6%	69	0.1%	218	0.3%	186	0.2%
Oct	77	0.1%	337	0.5%	49	0.1%	153	0.2%	177	0.3%
Nov	110	0.2%	129	0.2%	31	0.0%	104	0.1%	164	0.2%
Dec	202	0.3%	156	0.2%	12	0.0%	146	0.2%	200	0.2%

In order to help understand the frequency of offer capping in more detail, Table C-19 through Table C-23 show the number of generating units that met the specified criteria for total offer-capped run hours and percentage of offer-capped run hours for the years 2004 through 2008.

Table C-19 Offer-capped unit statistics: Calendar year 2004

Run Hours Offer-Capped, Percent Greater Than Or Equal To:	2004 Offer-Capped Hours Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	0	1	1	5	3	5
80% and < 90%	3	0	0	5	6	10
75% and < 80%	1	0	4	0	1	7
70% and < 75%	0	1	0	0	1	7
60% and < 70%	1	1	0	0	0	7
50% and < 60%	0	0	0	1	1	13
25% and < 50%	1	1	1	3	6	32
10% and < 25%	2	0	2	3	16	38

Table C-20 Offer-capped unit statistics: Calendar year 2005

Run Hours Offer-Capped, Percent Greater Than Or Equal To:	2005 Offer-Capped Hours Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	12	1	0	1	2	2
80% and < 90%	7	6	0	6	7	10
75% and < 80%	0	1	3	3	8	3
70% and < 75%	0	0	1	2	4	4
60% and < 70%	1	0	3	2	8	9
50% and < 60%	0	0	2	0	2	10
25% and < 50%	2	9	1	3	10	49
10% and < 25%	0	0	1	0	6	33

Table C-21 Offer-capped unit statistics: Calendar year 2006

Run Hours Offer-Capped, Percent Greater Than Or Equal To:	2006 Offer-Capped Hours Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	3	0	0	1	2	0
80% and < 90%	1	5	1	4	3	7
75% and < 80%	0	1	0	2	6	10
70% and < 75%	0	0	0	2	6	18
60% and < 70%	0	1	1	3	5	27
50% and < 60%	0	2	0	0	0	12
25% and < 50%	0	2	1	2	1	31
10% and < 25%	0	0	0	3	9	41

Table C-22 Offer-capped unit statistics: Calendar year 2007

Run Hours Offer-Capped, Percent Greater Than Or Equal To:	2007 Offer-Capped Hours					
	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	2	1	3	2	6	0
80% and < 90%	15	3	0	14	13	6
75% and < 80%	0	0	0	0	2	4
70% and < 75%	0	0	2	0	1	3
60% and < 70%	0	0	0	1	3	24
50% and < 60%	1	0	0	0	0	21
25% and < 50%	0	0	0	0	0	51
10% and < 25%	0	0	0	3	12	37

Table C-23 Offer-capped unit statistics: Calendar year 2008

Run Hours Offer-Capped, Percent Greater Than Or Equal To:	2008 Offer-Capped Hours					
	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	0	0	0	1	1	4
80% and < 90%	0	0	1	0	4	10
75% and < 80%	0	0	5	4	4	11
70% and < 75%	1	0	1	2	4	9
60% and < 70%	1	0	0	4	4	30
50% and < 60%	0	0	2	3	3	20
25% and < 50%	0	5	10	11	10	57
10% and < 25%	1	0	1	0	6	48

APPENDIX D – INTERCHANGE TRANSACTIONS

In competitive wholesale power markets, market participants' decisions to buy and sell power are based on actual and expected prices. If contiguous wholesale power markets incorporate security-constrained nodal pricing, well-designed interface pricing provides economic signals for import and export decisions by market participants, although those signals may be attenuated by a variety of institutional arrangements.

In order to understand the data on imports and exports, it is important to understand the institutional details of completing import and export transactions. These include the Open Access Real-time Information System (OASIS), North American Electric Reliability Council (NERC) Tags, neighboring balancing authority check out and transaction curtailment rules.

Transactions Background

OASIS Products

The OASIS products available for reservation include firm, network, non-firm and spot import service. The product type designated on the OASIS reservation determines when and how the transaction can be curtailed.

- **Firm.** Transmission service that is intended to be available at all times to the maximum extent practicable, subject to an emergency, and unanticipated failure of a facility, or other event beyond the control of the owner or operator of the facility, or the Office of the Interconnection.

- **Network.** Transmission service that is for the sole purpose of serving network load. Network transmission service is only eligible to network customers.

- **Non-Firm.** Point-to-point transmission service under the PJM tariff that is reserved and scheduled on an as-available basis and is subject to curtailment or interruption. Non-firm point-to-point transmission service is available on a stand-alone basis for periods ranging from one hour to one month.

- **Spot Import.** PJM introduced the concept of spot market imports with the introduction of the PJM Energy Market on April 1, 1997 (Marginal Clearing Price). It was introduced as an option for non-load serving entities to offer into the PJM spot market at the border/interface as price takers, therefore reducing the marginal cost of energy to load. In 2007, spot imports were added to the OASIS to add transparency and to properly account for the impacts of this network service on flowgates external to the PJM Transmission System. Prior to April 2007, PJM did not limit spot import service, preferring to let market prices ration the use of the service which is not physically limited. PJM interpreted its Joint Operating Agreement (JOA) with the Midwest ISO to require a limitation on spot import service in order to limit the impact of such transactions on selected external flowgates.[1] The rule caused the availability of spot import service to be limited by the Available Transmission Capacity (ATC) on the transmission path.

1 See "WPC White Paper" (April 20, 2007) (Accessed December 29, 2008)<http://www.pjm.com/~/media/etools/oasis/wpc-white-paper.ashx>(97 KB).

Source and Sink

The source and sink of an OASIS reservation designate the buses on the PJM system for which settlement LMPs are calculated. For import external energy transactions, the source defaults to the external interface as determined by the selected Point of Receipt (POR) and Point of Delivery (POD). For external energy transactions, the sink defaults to the external interface as determined by the selected POR and POD. For wheel through transactions, both the source and sink default to the external interfaces as determined by the selected POR and POD (the source defaults to the POR interface and the sink defaults to the POD interface). The market participant can then select the source or sink that is not pre-determined by the selected path. This selection determines the explicit congestion charge that the market participant is exposed to, as congestion is calculated as the difference in LMP from the sink to the source.

NERC Tagging

A NERC Tag is required for all external energy transactions. Only after a valid transmission reservation is acquired can a NERC Tag be created. If a ramp reservation has been made in advance, the market participant can enter the ramp reservation ID on the NERC Tag, otherwise, if no ramp reservation has been created, upon submission of the NERC Tag, PJM will attempt to create one. If there is available ramp at the time the NERC Tag is received by PJM, a ramp reservation will be created. If there is no ramp availability to match the tagged energy profile, the NERC Tag will be denied.

While the OASIS has a path component, this path only reflects the path of energy into or out of PJM to one neighboring balancing authority. The NERC Tag requires the complete path to be specified from the Generation Control Area (GCA) to the Load Control Area (LCA). This complete path is utilized by PJM to determine the interface pricing point which PJM will associate with the transaction.

Neighboring Balancing Authority Checkout

PJM operators must verify all requested energy schedules with its neighboring balancing authorities. Only if the neighboring balancing authority agrees with the expected interchange will the transaction flow. If there is a disagreement in the expected interchange for any 15 minute interval, the system operators must work to resolve the difference. It is important that both balancing authorities enter the same values in their Energy Management Systems (EMS) so as to avoid inadvertent energy from flowing between balancing authorities.

With the exception of the New York Independent System Operator (NYISO), all neighboring balancing authorities handle transaction requests the same way as PJM (i.e. via the NERC Tag). This helps facilitate interchange transaction checkouts, as all balancing authorities are receiving the same information. While the NYISO also requires NERC Tags, they utilize their Market Information System (MIS) as their primary scheduling tool. The MIS evaluates all bids and offers each hour, and performs a least cost economic dispatch solution. This evaluation accepts or denies individual transactions in whole or in part. Upon market clearing, the NYISO implements NERC Tag adjustments to match the output of the MIS. PJM and the NYISO can verify interchange transactions once the NYISO Tag adjustments are sent and approved. The results of the adjustments made by the NYISO affect PJM operations, as the adjustments often cause large swings in expected ramp for the next hour.

Curtailment of Transactions

Once a transaction has been implemented, energy flows between balancing authorities. Transactions can be curtailed under several conditions, including economic and reliability considerations. There are three types of economic curtailments: curtailments of dispatchable schedules; OASIS designation curtailments; and market participant self-curtailments. System reliability curtailments are termed TLRs or transmission loading relief.

A dispatchable external energy transaction (also known as “real-time with price”) is one in which the market participant designates a floor or ceiling price on their external transaction from which they would like the energy to flow. For example, an import dispatchable schedule specifies that the market participant only wishes to load the transaction if the LMP at the interface from which the transaction is entering the PJM footprint reaches a specified limit (the minimum LMP they are willing to sell at). An export dispatchable schedule specifies the maximum LMP at the interface from which the market participant wishes to purchase the power from PJM.

PJM system operators evaluate dispatchable transactions 30 minutes prior to the start of every hour of the energy profile. If the system operator expects the floor (or ceiling) price to be realized over the next hour, they contact the market participant informing them that they are loading the transaction. Once loaded, the dispatchable transaction will run for the next hour. If at any time the system operator does not feel that the transaction will be economic, they will elect to curtail the dispatchable transaction. Dispatchable schedules can be viewed as a generation offer, with a minimum run time of one hour. If prices are such that the transaction should not have been loaded, it will be made whole in the settlement process.

Not willing to pay congestion transactions can be curtailed if there is realized congestion between the designated source and sink.

Spot import service is dispatchable at a price of zero, by definition. If the interface price reaches zero, PJM system operators will curtail all transactions using spot import service flowing over that interface.

A market participant may curtail their transactions. All self curtailments must be requested on 15 minute intervals. In order for PJM to approve a self curtailment request, there must be available ramp for the modification.

Transmission Loading Relief (TLR)

TLRs are called to control flows on electrical facilities when economic redispatch cannot solve overloads on those facilities. TLRs are generally called to control flows related to external balancing authorities, as redispatch within an LMP market can generally resolve overloads on internal transmission facilities.

NYISO Issues

If interface prices were defined in a comparable manner by PJM and NYISO, if identical rules governed external transactions in PJM and NYISO, if time lags were not built into the rules governing such transactions and if no risks were associated with such transactions, then prices at the interfaces would be expected to be very close and the level of transactions would be expected to be related to any price differentials. The fact that none of these conditions exists is important in explaining the observed relationship between interface prices and inter-ISO power flows, and those price differentials.[2]

There are institutional differences between PJM and NYISO markets that are relevant to observed differences in border prices.[3] NYISO requires hourly bids or offer prices for each export or import transaction and clears its market for each hour based on hourly bids.[4] Import transactions to NYISO are treated by NYISO as generator bids at the NYISO/PJM proxy bus. Export transactions are treated by NYISO as price-capped load offers. Competing bids and offers are evaluated along with other NYISO resources and a proxy bus price is derived. Bidders are notified of the outcome. This process is repeated, with new bids and offers each hour. A significant lag exists between the time when offers and bids are submitted to NYISO and the time when participants are notified that they have cleared. The lag is a result of the functioning of the real-time commitment (RTC) system and the fact that transactions can only be scheduled at the beginning of the hour.

As a result of NYISO's RTC timing, market participants must submit bids or offers by no less than 75 minutes before the operating hour. The bid or offer includes the MW volume desired and, for imports into NYISO, the asking price or, for exports out of NYISO, the price the participants are willing to pay. The required lead time means that participants make price and MW bids or offers based on expected prices. Transactions are accepted only for a single hour.

Under PJM operating practices, market participants must make a request to import or export power at one of PJM's interfaces at least 20 minutes before the desired start which can be any quarter hour.[5] The duration of the requested transaction can vary from 45 minutes to an unlimited amount of time. Generally, PJM market participants provide only the MW, the duration and the direction of the real-time transaction. While bid prices for transactions are allowed in PJM, only about 1 percent of all transactions submit an associated price. Transactions are accepted, with virtually no lag, in order of submission based on whether PJM has the capability to import or export the requested MW. Since they receive the actual real-time price for their scheduled imports or exports, these transactions are price takers in the Real-Time Energy Market. As in NYISO, the required lead time means that participants must make offers to buy or sell MW based on expected prices, but the required lead time is substantially shorter in the PJM market.

2 See also the discussion of these issues in the *2005 State of the Market Report*, Section 4, "Interchange Transactions" (March 8, 2006).
3 See the *2005 State of the Market Report* (March 8, 2006), pp. 195-198.
4 See NYISO. "NYISO Transmission Services Manual," Version 2.0 (February 1, 2005) (Accessed January 15, 2009) <http://www.nyiso.com/public/webdocs/documents/manuals/operations/tran_ser_mnl.pdf> (463 KB).
5 See PJM. "Manual 41: Managing Interchange" (November 24, 20087) (Accessed January 15, 2009) < http://www.pjm.com/documents/~/media/documents/manuals/m41.ashx> (291 KB).

NYISO rules provide that RTC results should be available 45 minutes before the operating hour. Thus winning bidders have 25 minutes from the time when RTC results indicate that their transaction will flow to meet PJM's 20-minute notice requirement. To get a transaction cleared with PJM, the market participant must have a valid NERC Tag, an OASIS reservation and a PJM ramp reservation. Each of these requirements takes time to process.

The length of required lead times in both markets may be a contributor to the observed relationship between price differentials and flows. Market conditions can change significantly in a relatively short time. The resulting uncertainty could weaken the observed relationship between contemporaneous interface prices and flows.

Consolidated Edison Company (Con Edison) and Public Service Electric and Gas Company (PSE&G) Wheeling Contracts

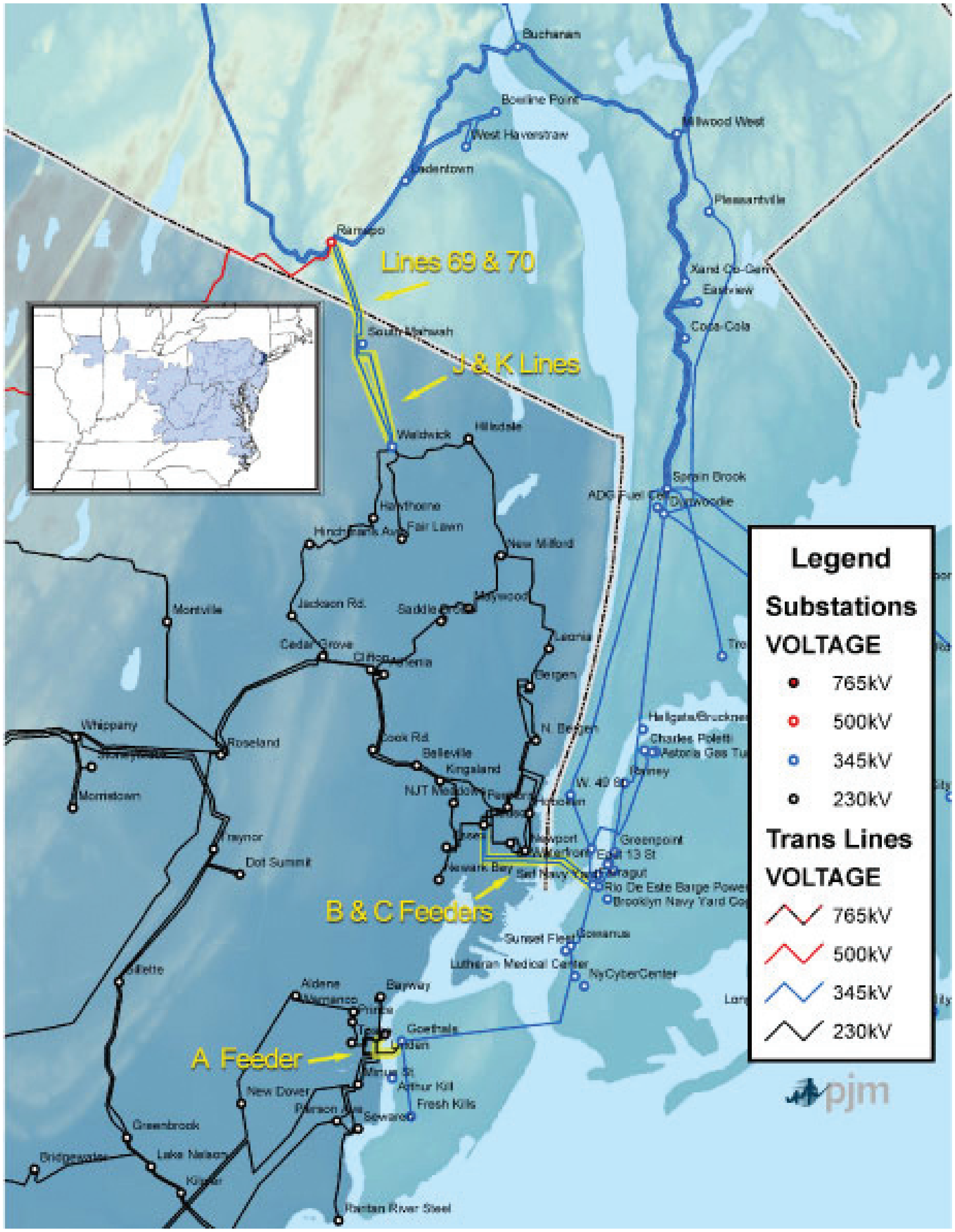
To help meet the demand for power in New York City, Con Edison uses electricity generated in upstate New York and wheeled through New York and New Jersey. A common path is through Westchester County using lines controlled by NYISO. Another path is through northern New Jersey using lines controlled by PJM. This wheeled power creates loop flow across the PJM system. The Con Edison/PSE&G contracts governing the New Jersey path evolved during the 1970s and were the subject of a Con Edison complaint to the FERC in 2001. In May 2005, the FERC issued an order setting out a protocol developed by the two companies, PJM and NYISO.[6] In July 2005, the protocol was implemented. Con Edison filed a protest with the FERC regarding the delivery performance in January 2006.[7]

The contracts provide for the delivery of up to 1,000 MW of power from Con Edison's Ramapo Substation in Rockland County, New York, to PSE&G at its Waldwick Switching Substation in Bergen County, New Jersey. PSE&G then wheels the power across its system and delivers it back to Con Edison across lines connecting directly into the city. (See Figure D-1.) Two separate contracts cover these wheeling arrangements. A 1975 agreement covers delivery of up to 400 MW through Ramapo (New York) to PSE&G's Waldwick Switching Station (New Jersey) then to the New Milford Switching Station (New Jersey) via the J line and ultimately from the Linden Switching Station (New Jersey) to the Goethals Substation (New York) and from the Hudson Generating Station (New Jersey) to the Farragut Switching Station (New York), via the A and B feeders, respectively. A 1978 agreement covers delivery of up to an additional 600 MW through Ramapo to Waldwick then to Fair Lawn, via the K line, and ultimately through a second Hudson-to-Farragut line, the C feeder. In 2001, Con Edison alleged that PSE&G had underdelivered on the agreements and asked the FERC to resolve the issue.

6 111 FERC ¶ 61,228 (2005).

7 Protest of the Consolidated Edison Company of New York, Inc., Protest, Docket No. EL02-23 (January 30, 2006).

Figure D-1 Con Edison and PSE&G wheel



Initial Implementation of the FERC Protocol

In May 2005, the FERC issued an order setting out a protocol developed by the four parties.[8] The protocol was implemented in July 2005.

The Day-Ahead Energy Market Process

The protocol allows Con Edison to elect up to the flow specified in each contract through the PJM Day-Ahead Energy Market. These elections are transactions in the PJM Day-Ahead Energy Market. The 600 MW contract is for firm service and the 400 MW contract has a priority higher than non-firm service but less than firm service. These elections obligate PSE&G to pay congestion costs associated with the daily elected level of service under the 600 MW contract and obligate Con Edison to pay congestion costs associated with the daily elected level of service under the 400 MW contract. The interface prices for this transaction are not defined PJM interface prices, but are defined in the protocol based on the actual facilities governed by the protocol.

Under the FERC order, PSE&G is assigned Financial Transmission Rights (FTRs) associated with the 600 MW contract. The PSE&G FTRs are treated like all other FTRs. In 2008, PSE&G's FTR revenues were less than its congestion charges by $26,250 after adjustments. (Revenues were approximately $14,250 less than charges in 2007.) Under the FERC order, Con Edison receives credits on an hourly basis for its elections under the 400 MW contract from a pool containing any excess congestion revenue after hourly FTRs are funded. In 2008, Con Edison's congestion credits were $268,368 less than its day-ahead congestion charges. Con Edison also had negative day-ahead congestion charges, with the result that Con Edison's total credits exceeded its congestion charges by $213,535. (Credits had been approximately $1.7 million less than charges in 2007.) Table D-1 shows the monthly details for both PSE&G and Con Edison. The protocol states:

> If there is congestion in PJM that affects the portion of the wheel that is associated with the 400 MW contract, PJM shall re-dispatch for the portion of the 400 MW contract for which ConEd specified it was willing to pay congestion, and ConEd shall pay for the re-dispatch. ConEd will be credited back for any congestion charges paid in the hour to the extent of any excess congestion revenues collected by PJM that remain after congestion credits are paid to all other firm transmission customers. Such credits to ConEd shall not exceed congestion payments owed or made by it.[9]

In effect, Con Edison has been given congestion credits that are the equivalent of a class of FTRs covering positive congestion with subordinated rights to revenue. However, Con Edison is not treated as having an FTR when congestion is negative. An FTR holder in that position would pay the negative congestion credits, but Con Edison does not. The protocol's provisions about congestion payments clearly cover congestion charges and offsetting congestion credits, but are not explicit on the treatment of Con Edison's negative congestion credits, which were $213,535 in 2008. The parties should address this issue.

8 111 FERC ¶ 61,228 (2005).
9 PJM Interconnection, L.L.C., Operating Protocol for the Implementation of Commission Opinion No. 476, Docket No. EL02-23-000 (Phase II) (Effective: July 1, 2005), Original Sheet No. 6 <http://www.pjm.com/~/media/documents/agreements/20050701-attachment-iv-operating-protocol.ashx> (327 KB).

The Real-Time Energy Market Process

Under the terms of the protocol, Con Edison can make a real-time election of its desired flow for each hour in the Real-Time Energy Market. If this election differs from its day-ahead schedule, the company is subject to the resultant charges or credits based on the difference between day-ahead and real-time prices. The real-time election differed from the day-ahead schedule in 5 percent of the hours in 2008.

Table D-1 Con Edison and PSE&G wheel settlements data: Calendar year 2008

		Con Edison			PSE&G		
		Day Ahead	Balancing	Total	Day Ahead	Balancing	Total
January	Congestion Charge	$164,163	($17,812)	$146,351	$287,369	$0	$287,369
	Congestion Credit			$190,400			$287,369
	Adjustment for defaults	($5,399)		($5,399)	($1,780)		($1,780)
	Net Charge			($38,650)			$1,780
February	Congestion Charge	$5,469	$10,333	$15,803	$20,770	$0	$20,770
	Congestion Credit			$81,674			$20,770
	Adjustment for defaults	($3,998)		($3,998)	($1,374)		($1,374)
	Net Charge			($61,874)			$1,374
March	Congestion Charge	$115,853	($1,839)	$114,014	$174,126	$0	$174,126
	Congestion Credit			$141,036			$174,126
	Adjustment for defaults	($2,376)		($2,376)	($670)		($670)
	Net Charge			($24,646)			$670
April	Congestion Charge	$303,483	$0	$303,483	$481,506	$0	$481,506
	Congestion Credit			$308,958			$481,506
	Adjustment for defaults	($682)		($682)	($147)		($147)
	Net Charge			($4,792)			$147
May	Congestion Charge	$752,197	($24,556)	$727,641	$1,140,758	$0	$1,140,758
	Congestion Credit			$752,944			$1,140,758
	Adjustment for defaults	($1,615)		($1,615)	($492)		($492)
	Net Charge			($23,688)			$492
June	Congestion Charge	$592,331	($7,259)	$585,072	$894,608	$0	$894,608
	Congestion Credit			$606,219			$894,608
	Adjustment for defaults	$997		$997	$374		$374
	Net Charge			($22,144)			($374)

		Con Edison			PSE&G		
		Day Ahead	Balancing	Total	Day Ahead	Balancing	Total
July	Congestion Charge	$1,056,304	$0	$1,056,304	$1,600,758	$0	$1,600,758
	Congestion Credit			$1,063,359			$1,600,758
	Adjustment for defaults	$0		$0	$0		$0
	Net Charge			($7,055)			$0
August	Congestion Charge	$146,243	($32,711)	$113,532	$219,364	($40,018)	$179,346
	Congestion Credit			$147,523			$219,364
	Adjustment for defaults	$0		$0	($682)		($682)
	Net Charge			($33,991)			($39,336)
September	Congestion Charge	$209,630	$2,125	$211,755	$366,394	$0	$366,394
	Congestion Credit			$85,305			$348,301
	Adjustment for defaults	$0		$0	($661)		($661)
	Net Charge			$126,450			$18,754
October	Congestion Charge	$170,129	$0	$170,129	$392,606	$0	$392,606
	Congestion Credit			$82,162			$386,591
	Adjustment for defaults	($4,037)		($4,037)	($652)		($652)
	Net Charge			$92,004			$6,666
November	Congestion Charge	$420,082	($218)	$419,864	$651,628	$0	$651,628
	Congestion Credit			$207,388			$633,053
	Adjustment for defaults	$0		$0	$0		$0
	Net Charge			$212,476			$18,575
December	Congestion Charge	$125,485	($8)	$125,477	$195,562	$0	$195,562
	Congestion Credit			$126,034			$218,077
	Adjustment for defaults	$0		$0	$0		$0
	Net Charge			($557)			($22,515)
Total	Congestion Charge	$4,061,370	($71,943)	$3,989,426	$6,425,449	($40,018)	$6,385,431
	Congestion Credit			$3,793,002			$6,405,281
	Adjustment for defaults			($17,110)			($6,082)
	Net Charge			$213,535			($13,768)

APPENDIX E – CAPACITY MARKET

Background

PJM and its members have long relied on capacity obligations as one of the methods to ensure reliability. Under the Reliability Assurance Agreement (RAA) governing the Capacity Market operated by the PJM regional transmission organization (RTO), each load-serving entity (LSE) must own or purchase capacity resources greater than, or equal to, its capacity obligation.

On June 1, 2007, the Reliability Pricing Model (RPM) Capacity Market design was implemented in PJM, replacing the Capacity Credit Market (CCM) Capacity Market design. This appendix explains certain key features of the RPM design in more detail.[1]

Demand

VRR Curves

Under RPM, PJM establishes variable resource requirement (VRR) curves for the PJM RTO and for each constrained locational deliverability area (LDA). The VRR curve is a demand curve based on three price-quantity points. The demand curve quantities are based on negative and positive adjustments to the reliability requirement. The demand curve prices are based on multipliers applied to the net cost of new entry (CONE). Net CONE is CONE minus the energy and ancillary service revenue offset (E&AS).[2]

The PJM reliability requirement represents the target level of reserves required to meet PJM reliability standards. It is the RTO peak-load forecast multiplied by the RTO forecast pool requirement (FPR) less the sum of any unforced capacity (UCAP) obligations served by fixed resource requirement (FRR) entities, all measured in UCAP.

Load Obligations

Participation by LSEs in the RPM for load served in PJM control zones is mandatory, except for those LSEs that have elected the FRR alternative.[3] Under RPM, each LSE that serves load in a PJM zone during the delivery year is responsible for paying a locational reliability charge equal to its daily unforced capacity obligation in the zone multiplied by the final zonal capacity price. LSEs may choose to hedge their locational reliability charge obligations by directly offering resources in the Base Residual Auction (BRA) and Second Incremental Auction or by designating self-supplied resources (resources directly owned or resources contracted for through unit-specific bilateral purchases) as self-scheduled to cover their obligation in the Base Residual Auction.

1 This section relies upon the cited PJM manuals where additional detail may be found.

2 See PJM. "Manual 18: PJM Capacity Market," Revision 5 (Effective October 3, 2008), p. 25 <http://www.pjm.com/documents/~/media/documents/manuals/m18.ashx> (1.19 MB).

3 See PJM. "Manual 18: PJM Capacity Market," Revision 5 (Effective October 3, 2008), p. 12 <http://www.pjm.com/documents/~/media/documents/manuals/m18.ashx> (1.19 MB).

Base UCAP Obligations

A base RTO UCAP obligation is determined after the clearing of the BRA and is posted with the BRA results. The base RTO UCAP obligation is equal to the sum of the UCAP obligation satisfied through the BRA plus the forecast RTO interruptible load for reliability (ILR) obligation. Base zonal UCAP obligations are defined for each zone as an allocation of the RTO UCAP obligation based on zonal, peak-load forecasts and zonal ILR obligations. The zonal UCAP obligation is equal to the zonal, weather-normalized summer peak for the summer four years prior to the delivery year multiplied by the base zonal RPM scaling factor and the FPR plus the forecast zonal ILR obligation.

Final UCAP Obligation

The final RTO UCAP obligation is determined after the clearing of the Second Incremental Auction (IA) and is posted with the second IA results. The final RTO UCAP obligation is equal to the sum of the UCAP obligation satisfied through the BRA and the second IA plus the forecast RTO ILR obligation. The final zonal UCAP obligation is equal to the base zonal UCAP obligation plus the RTO UCAP obligation satisfied in the second IA multiplied by the zone's percentage allocation of the obligation satisfied in the second IA.

LSE Daily UCAP Obligation

Obligation peak load is the peak-load value on which LSEs' UCAP obligations are based. The obligation peak-load allocation for a zone is constant and effective for the entire delivery year. The daily UCAP obligation of an LSE in a zone/area equals the LSE's obligation peak load in the zone/area multiplied by the final zonal RPM scaling factor and the FPR.

Capacity Resources

Capacity resources may consist of generation resources, load management resources and qualifying transmission upgrades, all of which must meet PJM-specific criteria.[4] Generation resources may be located within or outside of PJM, but they must be committed to serving load within PJM and must pass tests regarding the capability of generation to serve load and to deliver energy.

Generation Resources

Generation resources may consist of existing generation, planned generation, and bilateral contracts for unit-specific capacity resources. Existing generation located within or outside PJM is eligible to be offered into RPM Auctions or traded bilaterally if it meets defined requirements.[5] Planned generation that is participating in PJM's Regional Transmission Expansion Planning (RTEP) Process is eligible to be offered into RPM Auctions if it meets defined requirements.

4 See PJM. "Manual 18: PJM Capacity Market," Revision 5 (Effective October 3, 2008), p. 28 <http://www.pjm.com/documents/~/media/documents/manuals/m18.ashx> (1.19 MB).
5 See PJM. "Manual 18: PJM Capacity Market," Revision 5 (October 3, 2008), p. 29 <http://www.pjm.com/documents/~/media/documents/manuals/m18.ashx> (1.19 MB).

Load Management Resources

Load management is the ability to reduce load upon request.[6] A load management resource is eligible to be offered as a demand resource (DR) or interruptible load for reliability (ILR). DR is a load resource that is offered into an RPM Auction as capacity and receives the relevant LDA or RTO resource-clearing price. ILR is a load resource that is not offered into the RPM Auction, but receives the final zonal ILR price determined after the close of the second incremental auction. DR and ILR resources must meet defined requirements.

Qualified Transmission Upgrades

A qualifying transmission upgrade may be offered into the BRA to increase import capability into a transmission-constrained LDA. Such transmission upgrades must meet the identified requirements.[7]

Obligations of Capacity Resources

The sale of a generating unit as a capacity resource within PJM entails obligations for the generation owner. The first four of these requirements, listed below, are essential to the definition of a capacity resource and contribute directly to system reliability.

- **Energy Recall Right.** PJM rules specify that when a generation owner sells capacity resources from a unit, the seller is contractually obligated to allow PJM to recall the energy generated by that unit if the energy is sold outside of PJM. This right enables PJM to recall energy exports from capacity resources when it invokes emergency procedures. The recall right establishes a link between capacity and actual delivery of energy when it is needed. Thus, PJM can call upon energy from all capacity resources to serve load. When PJM invokes the recall right, the energy supplier is paid the PJM Real-Time Energy Market price.

- **Day-Ahead Energy Market Offer Requirement.** Owners of PJM capacity resources are required to offer their output into PJM's Day-Ahead Energy Market. When LSEs purchase capacity, they ensure that resources are available to provide energy on a daily basis, not just in emergencies. Since day-ahead offers are financially binding, PJM capacity resource owners must provide the offered energy at the offered price if the offer is accepted in the Day-Ahead Energy Market. This energy can be provided by the specific unit offered, by a bilateral energy purchase, or by an energy purchase from the Real-Time Energy Market.

6 See PJM. "Manual 18: PJM Capacity Market," Revision 5 (Effective October 3, 2008), p. 33 <http://www.pjm.com/documents/~/media/documents/manuals/m18.ashx> (1.19 MB).
7 See PJM. "Manual 18: PJM Capacity Market," Revision 5 (Effective October 3, 2008), p. 41 <http://www.pjm.com/documents/~/media/documents/manuals/m18.ashx> (1.19 MB).

- **Deliverability.** To qualify as a PJM capacity resource, energy from the generating unit must be deliverable to PJM load. Capacity resources must be deliverable, consistent with a loss of load expectation as specified by the reliability principles and standards, to the total system load, including portion(s) of the system that may have a capacity deficiency.[8] In addition, for external capacity resources used to meet an accounted-for obligation within PJM, capacity and energy must be delivered to the metered, PJM boundaries through firm transmission service.

- **Generator Outage Reporting Requirement.** Owners of PJM capacity resources are required to submit historical outage data to PJM pursuant to Schedule 12 of the RAA.[9]

CETO/CETL

Since the ability to import energy and capacity into LDAs may be limited by the existing transmission capability, PJM conducts a load deliverability analysis for each LDA.[10] The first step in this process is to determine the transmission import requirement into an LDA, called the capacity emergency transfer objective (CETO). This value, expressed in MW, is the transmission import capability required for each LDA to meet the area reliability criterion of loss of load expectation due to insufficient import capability alone, of one occurrence in 25 years when the LDA is experiencing a localized capacity emergency.

The second step is to determine the transmission import limit for an LDA, called the capacity emergency transfer limit (CETL), which is also expressed in MW. The CETL is the ability of the transmission system to deliver energy into the LDA when it is experiencing the localized capacity emergency used in the CETO calculation.

If CETL is less than CETO, capacity-related transmission constraints may result in locational price differences in the RPM.[11] This will also trigger the planning of transmission upgrades under the RTEP Process.

Generator Performance: NERC OMC Outage Cause Codes

Table E-1 includes a list of the North American Electric Reliability Council (NERC) GADS cause codes deemed outside management control (OMC). PJM does not automatically include cause codes 9200-9299 as outside management control for the purposes of calculating unforced capacity, with the exception of code 9250 under certain conditions.

8 Deliverable per PJM. "Reliability Assurance Agreement," Schedule 10 (Effective June 1, 2007), Original Sheet No. 50 <http://www.pjm.com/documents/agreements/~/media/documents/agreements/raa.ashx> (1.92 MB).

9 See PJM. "Reliability Assurance Agreement," Schedule 12 (Effective June 1, 2007), Original Sheet No. 54 <http://www.pjm.com/documents/agreements/~/media/documents/agreements/raa.ashx> (1.92 MB).

10 See PJM. "Manual 14B: Generation and Transmission Interconnection Planning, Attachment E: PJM Deliverability Methods," Revision 12 (Effective August 8, 2008), p. 41 <http://www.pjm.com/documents/~/media/documents/manuals/m14b.ashx> (474 KB). PJM Manual 14B indicates that all "electrically cohesive load areas" are tested.

11 See PJM. "Manual 18: PJM Capacity Market," Revision 5 (Effective October 3, 2008), p. 18, <http://www.pjm.com/documents/~/media/documents/manuals/m18.ashx> (1.19 MB).

Table E-1 NERC GADS cause codes deemed outside management control[12]

Cause Code	Reason for Outage
3600	Switchyard transformers and associated cooling systems - external
3611	Switchyard circuit breakers - external
3612	Switchyard system protection devices - external
3619	Other switchyard equipment - external
3710	Transmission line (connected to powerhouse switchyard to 1st Substation)
3720	Transmission equipment at the 1st substation (see code 9300 if applicable)
3730	Transmission equipment beyond the 1st substation (see code 9300 if applicable)
9000	Flood
9010	Fire, not related to a specific component
9020	Lightning
9025	Geomagnetic disturbance
9030	Earthquake
9035	Hurricane
9036	Storms (ice, snow, etc)
9040	Other catastrophe
9130	Lack of fuel (water from rivers or lakes, coal mines, gas lines, etc) where the operator is not in control of contracts, supply lines, or delivery of fuels
9135	Lack of water (hydro)
9150	Labor strikes company-wide problems or strikes outside the company's jurisdiction such as manufacturers (delaying repairs) or transportation (fuel supply) problems.
9250	Low Btu coal
9300	Transmission system problems other than catastrophes (do not include switchyard problems in this category; see codes 3600 to 3629, 3720 to 3730)
9320	Other miscellaneous external problems
9500	Regulatory (nuclear) proceedings and hearings - regulatory agency initiated
9502	Regulatory (nuclear) proceedings and hearings - intervener initiated
9504	Regulatory (environmental) proceedings and hearings - regulatory agency initiated
9506	Regulatory (environmental) proceedings and hearings - intervenor initiated
9510	Plant modifications strictly for compliance with new or changed regulatory requirements (scrubbers, cooling towers, etc.)
9590	Miscellaneous regulatory (this code is primarily intended for use with event contribution code 2 to indicate that a regulatory-related factor contributed to the primary cause of the event)

12 See NERC. "Generator Availability Data System Data Reporting Instructions," Appendix K <http://www.nerc.com/files/Appendix_K_Outside_Plant_Management_Control.pdf> (149 KB).

APPENDIX F – ANCILLARY SERVICE MARKETS

This appendix covers two subject areas: area control error and the details of regulation availability and price determination.

Area Control Error (ACE)

Area control error (ACE) is a real-time metric used by PJM operators to measure the instantaneous MW imbalance between load plus net interchange and generation within PJM.[1] PJM dispatchers seek to ensure grid reliability by balancing ACE. A dispatcher's success in doing so is measured by control performance standard 1 (CPS1) and balancing authority ACE limit (BAAL) performance. These measurements are mandated by the North American Electric Reliability Council (NERC).

In the absence of a severe grid disturbance, the primary tool used by dispatchers to minimize ACE is regulation. Regulation is defined as a variable amount of energy under automatic control which is independent of economic cost signal and is obtainable within five minutes. Regulation contributes to maintaining the balance between load and generation by moving the output of selected generators up and down via an automatic generation control (AGC) signal.[2]

Resources wishing to participate in the Regulation Market must pass certification and submit to random testing. Certification requires that resources be capable of and responsive to AGC. After receiving certification, all participants in the Regulation Market are tested to ensure that regulation capacity is fully available at all times. Testing occurs at times of minimal load fluctuation. During testing, units must respond to a regulation test pattern for 40 minutes and must reach their offered regulation capacity levels, up and down, within five minutes. Units whose monitored response is less than their offered regulation capacity have their regulating capacity reduced by PJM.[3]

During 2008 an experimental battery-powered regulation unit was installed at the PJM facility. Observation of this unit reveals that new types of units will require that PJM's regulation unit certification testing procedure as administered by PJM's Performance Compliance group be modified, perhaps tailored to the specific unit types. The test as it is now designed measures the ability of the unit to respond to its regulation min/max within five minutes. This has always been the critical regulating metric for steam and CT units. But other types of units can meet this criterion easily yet still be inadequate for regulation because they lack the capacity to regulate for the entire hour in the event that regulation is almost completely above or below the regulation set point. Such units might include battery, pumped hydro, and inertial regulation units.

1 "Two additional terms may be included in ACE under certain conditions – time error bias and manual add (a PJM dispatcher term). These provide for automatic inadvertent interchange payback and error compensation, respectively." See PJM. "Manual 12: Balancing Operations," Revision 18 (July 2, 2008), Section 3, "System Control" p. 11.

2 Regulation Market business rules are defined in PJM. "Manual 11: Scheduling Operations," Revision 37 (November 24, 2008), pp. 33-39.

3 See PJM. "Manual 12: Balancing Operations," Revision 18 (July 2, 2008), pp. 43-45., Section 4, pp. 47-51.

Control Performance Standard (CPS) and Balancing Authority ACE Limit (BAAL)

Two control performance standards are established by NERC for evaluating ACE control. One measure is a statistical measure of ACE variability and its relationship to frequency error. The purpose of the new BAAL standard is to maintain interconnection frequency within a predefined frequency profile under all conditions (normal and abnormal), to prevent frequency-related instability, unplanned tripping of load or generation, or uncontrolled separation or cascading outages that adversely impact the reliability of the interconnection.

- **CPS1.** NERC requires that the first CPS measure provide a measure of the balancing authority's performance. The measure is intended to provide the balancing authority with a frequency-sensitive evaluation of how well it has met its demand requirements. A minimum passing score for CPS1 is 100 percent.[4]

- **CPS2.** NERC also requires that the second CPS measure provide a measure of 10-minute ACE averages. CPS2 provides a control measure of excessive, unscheduled power flows that could result from large ACEs. CPS2 is measured by counting the number of 10-minute periods during a month when the 10-minute average of PJM's ACE is within defined limits known as L_{10}. The specific, 10-minute periods of each hour are those ending at 10, 20, 30, 40, 50 and 60 minutes after the hour. A passing score for CPS2 is achieved when 90 percent of these 10-minute periods during a single month are within L_{10}. From January 1, through December 31, 2008, PJM's L_{10} standard was 291.6 MW.

- **BAAL.** Since August 1, 2005, PJM has participated in the NERC "Balancing Standard Proof-of-Concept Field Test" which has established a new metric, balancing authority ACE limit (BAAL), as a possible substitute for CPS2. Participants in the field test have a waiver from meeting the CPS2 requirement for the duration of the field test. As a substitute, the field test participants are required to comply with BAAL limits, which have been established on a trial basis.[5] PJM measures the total number of minutes the BAAL limit is exceeded (high or low) compared to the total number of minutes for a month, with a passing level for this goal being set at 98 percent.

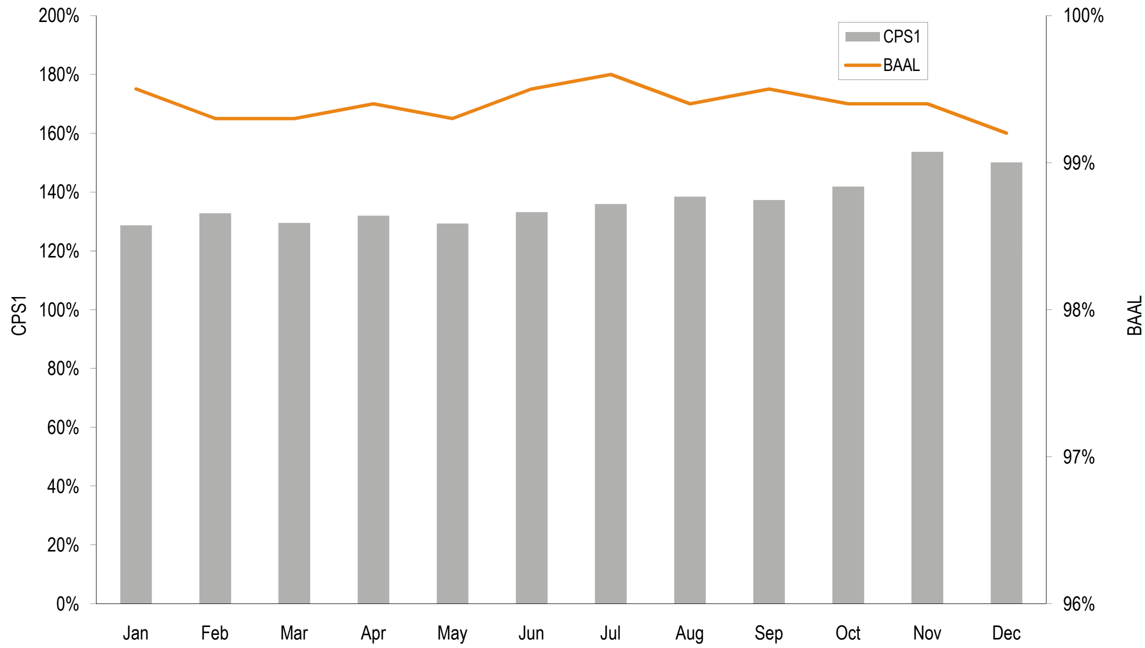
4 For more information about the definition and calculation of CPS, see PJM. "Manual 12: Balancing Operations," Revision 18 (July 2, 2008), pp. 76-77. The formal definition of CPS1 can be found in NERC's "Performance Standards Reference Document," Version 2 (November 21, 2002), Section B.1.1.1. The formal definition of CPS2 can be found in NERC's "Performance Standards Reference Document," Version 2 (November 21, 2002), Section B.1.1.2.

5 See PJM. "Manual 12: Balancing Operations," Revision 18 (July 2, 2008), pp. 76-77.

PJM's CPS/BAAL Performance

As Figure F-1 shows, PJM's performance relative to both the CPS1 and BAAL metrics was acceptable in calendar year 2008.

Figure F-1 PJM CPS1 and BAAL performance: Calendar year 2008



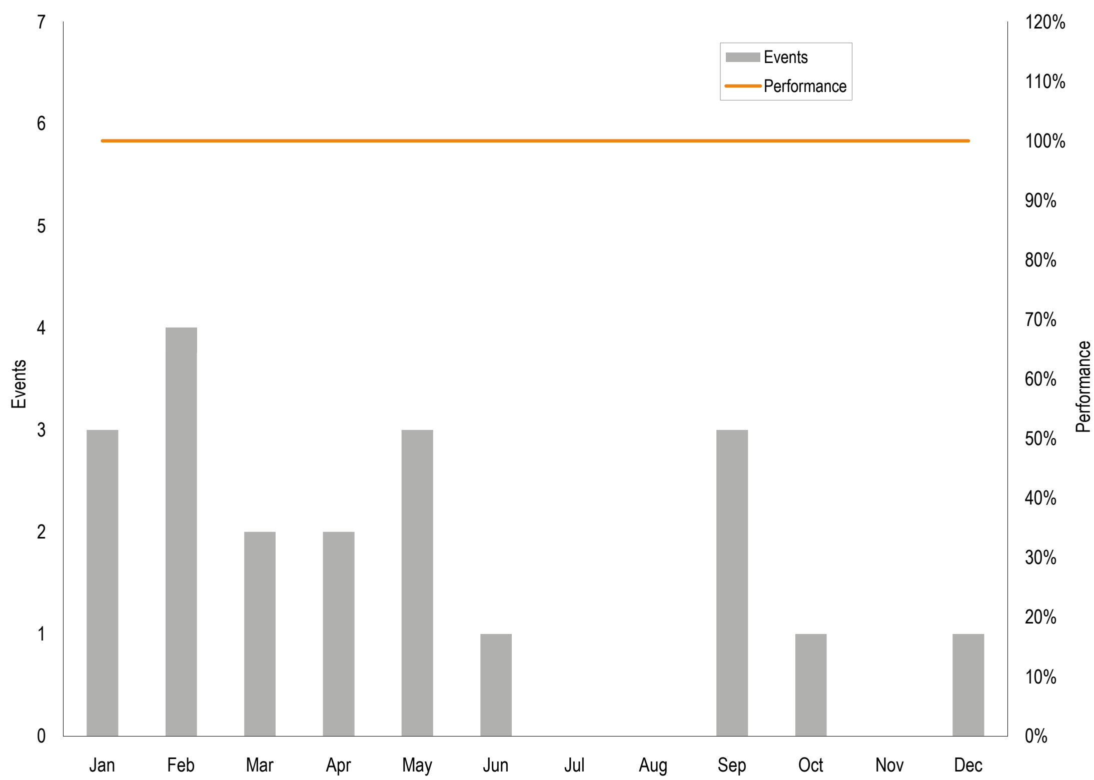
PJM dispatchers have to balance both ACE and frequency. Meeting the CPS1 standard requires balancing ACE and frequency on a monthly, running-average basis. Meeting the BAAL standard requires PJM dispatchers maintaining interconnection frequency within a predefined frequency profile under all conditions (normal and abnormal) to prevent frequency-related instability, unplanned tripping of load or generation, or uncontrolled separation or cascading outages that adversely impact the reliability of the interconnection.

PJM's DCS Performance

A dispatch performance metric that is directly related to synchronized reserve is the disturbance control standard (DCS).[6] DCS measures how well PJM dispatch recovers from a disturbance. A disturbance is defined as any ACE deviation greater than, or equal to, 80 percent of the magnitude of PJM's most severe single contingency loss. PJM currently interprets this to be any ACE deviation greater than 800 MW. Compliance with the NERC DCS is recovery to zero or predisturbance level within 15 minutes.

PJM experienced 20 DCS events during calendar year 2008 and successfully recovered from all of them. All events were caused by a major unit's tripping. Recovery times ranged from four minutes to 13 minutes. Figure F-2 illustrates the event count and performance by month. All of the events resulted in low ACE. The solution in 16 of the 20 events was to declare a 100 percent spinning event.

Figure F-2 DCS event count and PJM performance (By month): Calendar year 2008



6 For more information on the NERC DCS, see "Standard BAL-002-0 — Disturbance Control Performance" (April 1, 2005) <www.nerc.com/files/BAL-002-0.pdf> (61 KB).

Regulation Capacity, Daily Offers, Offered and Eligible, Hourly Assigned

The regulation market-clearing price (RMCP) is determined algorithmically by the PJM Market Operations Group. First, a theoretical, optimized energy dispatch is done based on current unit status and forecast LMP. Then the Market Operations Group creates a supply curve for regulation and for synchronized reserve of available units and their associated merit-order prices. The resulting supply curve is evaluated to see which if any of the owning companies are pivotal. Pivotal companies will have their resources offer capped at the lesser of their cost based or price based offer. The generating units of companies which are not pivotal will then have their offer reset to their price based offer and the market is cleared. Finally, the Market Operations Group assigns regulation and synchronized reserve to units in increasing order of price until the regulation MW and the synchronized reserve requirements are satisfied. The price of the most expensive unit required to satisfy the regulation requirement is the RMCP. Calculating the supply curves for three products (energy, regulation and synchronized reserve) interactively is complicated, but necessary to achieve the lowest overall cost after first taking into account units that self-schedule. In the event it is not possible to satisfy both regulation and synchronized reserve, regulation has the higher priority.

- **Regulation Capacity.** The sum of the regulation MW capability of all generating units which have qualified to participate in the Regulation Market is the theoretical maximum regulation capacity. This maximum regulation capacity varies over time because units that are certified for regulation may be decommissioned, fail regulation testing or be removed from the Regulation Market by their owners.

- **Regulation Offers.** All owners of generating units qualified to provide regulation may, but are not required to, offer their regulation capacity daily into the Regulation Market using the PJM market user interface. Regulating units may also self-schedule. Self-scheduled units have zero lost opportunity cost (LOC) and are the first to be assigned. Demand resources are eligible to offer regulation although during 2008 none qualified to do so. Demand resources have an LOC of zero. Under PJM rules, no more than 25 percent of the total regulation requirement may be supplied by demand resources. Total regulation offers are the sum of all regulation-capable units that offer regulation into the market for the day and that are not out of service or fully committed to provide energy. Owners of units that have entered offers into the PJM market user interface system have the ability to set unit status to "unavailable" for regulation for the day, or for a specific hour or set of hours. They also have the ability to change the amount of regulation MW offered in each hour. Unit owners do not have the ability to change their regulation offer price during a day. Starting in December, 2008, the PJM Market Users Interface allows regulation owners to enter cost data. For cost-based offers above $12 per MWh owners are required to enter cost data. All regulation offers are summed to calculate the total daily regulation offered, a figure that changes each hour.

- **Regulation Offered and Eligible.** Sixty minutes before the market hour, PJM runs synchronized reserve and regulation market-clearing software (SPREGO) to determine the amount of Tier 2 synchronized reserve required, to develop regulation and synchronized reserve supply curves, to assign regulation and synchronized reserve to specific units and to determine the RMCP. All regulation resource units which have made offers in the daily Regulation Market are evaluated by SPREGO for regulation. SPREGO then excludes units according to the following ordered criteria: a) Daily or hourly unavailable units; b) Units for which the economic minimum is set equal to economic maximum (unless the unit is a hydroelectric unit or has self-scheduled regulation); c) Units which are assigned synchronized reserve; d) Units for which regulation minimum is set equal to regulation maximum (unless the unit is a hydroelectric unit or has self-scheduled regulation); e) Units that are offline (except combustion turbine units).

  Even after SPREGO has run and selected units for regulation, PJM dispatchers can dispatch units uneconomically for several reasons including: to control transmission constraints; to avoid overgeneration during periods of minimum generation alert; to remove a unit temporarily unable to regulate; or to remove a unit with a malfunctioning data link.

  For each offered and eligible unit in the regulation supply, the regulation total offer price is calculated using the sum of the unit's regulation cost-based offer and the opportunity cost based on the forecast LMP, unit economic minimum and economic maximum, regulation minimum and regulation maximum, startup costs and relevant offer schedule. Based on this result, SPREGO determines if the period has three or fewer pivotal suppliers. If it does, all owners who are pivotal have their offers limited to the lesser of their cost or price offer. SPREGO uses price-based offers for those operators not cost-capped and re-solves. This solution is final. The MW offered and the calculated regulation offered prices are used to create a regulation supply curve. The Regulation and Synchronized Reserve Markets are cleared interactively with the Energy Market and operating reserve requirements to minimize the cost of the combined products subject to reactive limits, resource constraints, unscheduled power flows, interarea transfer limits, resource distribution factors, self-scheduled resources, limited fuel resources, bilateral transactions, hydrological constraints, generation requirements and reserve requirements.

- **Cleared Regulation.** Regulation actually assigned by SPREGO is cleared regulation. The clearing price established by SPREGO becomes the final clearing price. In real time, units that have been assigned regulation and synchronized reserve are expected to provide regulation and synchronized reserve for the designated hour. At any time before or during the hour, PJM dispatchers can redispatch units for reliability reasons. Such redispatch leads to a disparity between cleared regulation and settled regulation.

- **Settled Regulation.** Units providing regulation are compensated at the clearing price times their actual MW provided (as opposed to cleared MW) plus any actual lost opportunity costs associated with providing regulation. The cost per MW of settled regulation can be higher than the regulation clearing price because there can be a difference between actual and cleared MW, as well as real-time versus forecast nodal prices.

APPENDIX G – FINANCIAL TRANSMISSION AND AUCTION REVENUE RIGHTS

Appendix G provides examples of topics related to Financial Transmission Rights (FTRs) and Auction Revenue Rights (ARRs):

- The sources of total congestion revenue and the determination of FTR target allocations and congestion receipts;
- The procedure for prorating ARRs when transmission capability limits the number of ARRs that can be allocated; and
- The establishment of ARR target allocations and credits through the Annual FTR Auction.

FTR Target Allocations and Congestion Revenue

Table G-1 shows an example of the sources of total congestion revenue and the determination of FTR target allocations and congestion receipts.

Table G-1 Congestion revenue, FTR target allocations and FTR congestion credits: Illustration

Day-Ahead Congestion Revenue						
Pricing Node	Day-Ahead Congestion Price	Day-Ahead Load	Load Congestion Payments	Day-Ahead Generation	Generation Congestion Credits	Transmission Congestion Charges
A	$10	0	$0	100	$1,000	($1,000)
B	$15	50	$750	0	$0	$750
C	$20	50	$1,000	100	$2,000	($1,000)
D	$25	50	$1,250	0	$0	$1,250
E	$30	50	$1,500	0	$0	$1,500
Total		200	$4,500	200	$3,000	$1,500
Balancing Congestion Revenue						
Pricing Node	Real-Time Congestion Price	Load Deviation	Load Congestion Payments	Generation Deviation	Generation Congestion Credits	Transmission Congestion Charges
A	$8	0	$0	0	$0	$0
B	$18	0	$0	0	$0	$0
C	$25	3	$75	5	$125	($50)
D	$20	(5)	($100)	0	$0	($100)
E	$40	7	$280	0	$0	$280
Total		5	$255	5	$125	$130
Transmission congestion charges accounting						
Balancing transmission congestion charges						$130
+Day-ahead transmission congestion charges						$1,500
=Total transmission congestion charges						$1,630
FTR Target Allocations						
Path	Day-Ahead Path Price	FTR MW	FTR Target Allocations	Positive FTR Target Allocations	Negative FTR Target Allocations	
A-C	$10	50	$500	$500	$0	
A-D	$15	50	$750	$750	$0	
D-B	($10)	25	($250)	$0	($250)	
B-E	$15	50	$750	$750	$0	
Total		175	$1,750	$2,000	($250)	
Congestion accounting						
Transmission congestion charges						$1,630
+Negative FTR target allocations						$250
=Total congestion charges						$1,880
Positive FTR target allocations				$2,000		
-FTR congestion credits				$1,880		
=Congestion credit deficiency				$120		
FTR payout ratio				0.94		

ARR Prorating Procedure

Table G-2 shows an example of the prorating procedure for ARRs. If line A-B has a 100 MW rating, but ARR requests from two customers together would impose 175 MW of flow on it, the service request would exceed its capability by 75 MW. The first customer's ARR request (ARR #1) is for a total of 300 MW with a 0.50 impact on the constrained line. It would thus impose 150 MW of flow on the line. The second customer's request (ARR #2) is for a total of 100 MW with a 0.25 impact and would impose an additional 25 MW on the constrained line.

Table G-2 ARR allocation prorating procedure: Illustration

Line A-B Rating = 100 MW						
ARR #	Path	Per MW Effect on Line A-B	Requested ARRs	Resulting Line A-B Flow	Prorated ARRs	Prorated Line A-B Flow
1	C-D	0.50	300	150	150	75
2	E-F	0.25	100	25	100	25
Total			400	175	250	100

Equation G-1 Calculation of prorated ARRs

Individual prorated MW =
(Line capability) • (Individual requested MW / Total requested MW) • (1 / per MW effect on line).

The equation would then be solved for each request as follows:

ARR #1 prorated MW award = (100 MW) • (300 MW / 400 MW) • (1 / 0.50) = 150 MW; and

ARR #2 prorated MW award = (100 MW) • (100 MW / 400 MW) • (1 / 0.25) = 100 MW.

Together the prorated, awarded ARRs would impose a flow equal to line A-B's capability
(150 MW • 0.50) + (100 MW • 0.25) = 100 MW.

ARR Credits

Table G-3 shows an example of how ARR target allocations are established, how FTR auction revenue is generated and how ARR credits are determined. The purchasers of FTRs pay and the holders of ARRs are paid based on cleared nodal prices from the Annual FTR Auction. If total revenue from the auction is greater than the sum of the ARR target allocations, then the surplus is used to offset any FTR congestion credit deficiencies occurring in the hourly Day-Ahead Energy Market. For example, the FTR auction revenue is only $75 for the ARR on line A-D while the ARR target allocation is $150. The surplus FTR auction revenue from the other ARR paths is enough to cover the $75 deficiency and fulfill the ARR target allocation of $150.

Table G-3 ARR credits: Illustration

Path	Annual FTR Auction Path Price	ARR MW	ARR Target Allocation	FTR MW	FTR Auction Revenue	ARR Credits
A-C	$10	10	$100	10	$100	$100
A-D	$15	10	$150	5	$75	$150
B-D	$10	0	$0	20	$200	$0
B-E	$15	10	$150	5	$75	$150
Total		30	$400	40	$450	$400
ARR payout ratio = ARR credits / ARR target allocations = $400 / $400 = 100%						
Surplus ARR revenue = FTR auction revenue - ARR credits = $450 - $400 = $50						

APPENDIX H – CALCULATING LOCATIONAL MARGINAL PRICE

In order to understand the relevance of various measures of locational marginal price (LMP), it is important to understand how average LMPs are calculated across time and across buses. This appendix explains how PJM calculates average LMP and load-weighted, average LMP for the system, for a zone and, by extension, for any aggregation of buses, for an hour, for a day and for a year.[1] This appendix also explains how the Market Monitoring Unit (MMU) calculates average LMP for states, consistent with the PJM method for other aggregates.

Real-Time Hourly Integrated LMP and Real-Time Hourly Integrated Load

In PJM a real-time LMP is calculated at every bus for every five-minute interval.

The system real-time, five-minute, average LMP is the load-weighted, average LMP for that five-minute interval, calculated using the five-minute LMP at each load bus and the corresponding five-minute load at each load bus in the system. The sum of the product of the five-minute LMP and the five-minute load at each bus, divided by the sum of the five-minute loads across the buses equals the system load-weighted, average LMP for that five-minute interval.

In PJM, the real-time hourly LMP at a bus is equal to the simple average of each hour's 12 five-minute interval LMPs at that bus. This is termed the hourly integrated LMP at the bus. The hourly load at a bus is also calculated as the simple average of each hour's 12 five-minute interval loads at that bus. This is termed the hourly integrated load at the bus. The hourly values for LMP and load are the basis of PJM's settlement calculations.

Day-Ahead Hourly LMP and Day-Ahead Hourly Load

The day-ahead LMP is calculated at every bus for every hour from the day-ahead dispatch required to meet estimated nodal loads derived from the distribution factors plus nodal load from decrement bids (DECs) and price-sensitive load and nodal supply from generation offers and increment offers (INCs). The result is a full set of day-ahead nodal LMPs and cleared, nodal loads.

This measure of nodal, day-ahead load is used in system load-weighted, average LMP calculations. This is termed nodal, total day-ahead load here. Zonal, day-ahead hourly aggregate load is assigned to buses in the relevant zone using zonal distribution factors.

Day-ahead zonal distribution factors are calculated from historical real-time, bus-level load distributions that were in effect at 8 AM seven days prior. The use of load data from a period seven days prior to the DA price calculations provides a week day match but the lack of adjustment for other factors that affect bus-specific loads, including temperature, introduces a potentially significant inaccuracy in the load data used to clear the day-ahead market. This would be an issue to the extent that weather or other factors changes the relative size of nodal loads.

1 The unweighted, average LMP is also referred to as the simple average LMP.

Zonal, day-ahead, load-weighted LMP is calculated from nodal day-ahead LMP using zonal distribution factors as the load weights. This measure of load weights excludes bus specific loads, such as DECs, that clear in the day-ahead market. The exclusion of bus specific loads from the calculation of day ahead load weighted LMP means that the zonal day-ahead load weighted prices reported by PJM do not reflect the load weighted price paid by all load in a zone, but instead reflect only the price paid by the load that settles at the day ahead hourly zonal price.

Factor distributed load, used in the calculation of state load weighted average LMP, is calculated by multiplying day-ahead zonal hourly load (fixed plus price-sensitive load only) by day-ahead distribution factors. The factor distributed load calculation provides bus specific load weights, derived directly from the day ahead zonal distribution factors, which are used to calculate day-ahead load and load weighted average LMP for states with load buses in multiple zones or parts of zones. This methodology is used because it results in weighted LMPs that are consistent with how zonal factor weighted prices are determined by PJM. This means that where the zone buses are the same as state buses, the result will be the same. For example, the state of Maryland contains buses from the AP, BGE, DPL and Pepco zones, but the areas encompassed by these aggregates, with the exception of BGE, extend beyond the borders of the state. AP, for example, extends past the western portion of Maryland into Pennsylvania, Ohio, West Virginia and Virginia. To provide Maryland specific results for load and LMP, a Maryland aggregate is calculated using only those AP, BGE, DPL and Pepco load buses that are physically within the geographic boundaries of the state of Maryland.

Load-Weighted, Average LMP

Real Time

The system real-time, load-weighted, average LMP for an hour is equal to the sum of the product of the hourly integrated bus LMPs for each load bus and the hourly integrated load for each load bus, for the hour, divided by the sum of the hourly integrated bus loads for the hour.

The zonal real-time, load-weighted, average LMP for an hour is equal to the sum of the product of the hourly integrated bus LMPs for each load bus in a zone and the hourly integrated load for each load bus in that zone, divided by the sum of the real-time hourly integrated loads for each load bus in that same zone.

The real-time, load-weighted, average LMP for an hour for a state is equal to the sum of the product of the hourly integrated bus LMPs for each load bus in a state and the hourly integrated load for each load bus in that state, divided by the sum of the real-time hourly integrated loads for each load bus in that state.

The system real-time, load-weighted, average LMP for a day is equal to the product of the hourly integrated LMPs for each load bus and the hourly integrated load for each load bus, for each hour, summed over every hour of the day, divided by the sum of the hourly integrated bus loads for the system for the day.

The zonal real-time, load-weighted, average LMP for a day is equal to the product of each of the hourly integrated LMPs for each load bus in a zone and the hourly integrated load for each load bus in that zone, for each hour, summed over every hour of the day, divided by the sum of the hourly integrated bus loads at each load bus in that zone for the day.

The real-time, load-weighted, average LMP for a day for a state is equal to the product of each of the hourly integrated LMPs for each load bus in a state and the hourly integrated load for each load bus in that state, for each hour, summed over every hour of the day, divided by the sum of the hourly integrated bus loads at each load bus in that state for the day.

The system real-time, load-weighted, average LMP for a year is equal to the product of the hourly integrated LMPs and hourly integrated load for each load bus, summed across every hour of the year, divided by the sum of the hourly integrated bus loads at each load bus in the system for each hour in the year.

The zonal real-time load-weighted, average LMP for a year is equal to the product of each of the hourly integrated bus LMPs and hourly integrated load for each load bus in a zone, summed across every hour of the year, divided by the sum of the hourly integrated bus loads at each load bus in that zone for each hour in the year.

The real-time load-weighted, average LMP for a year for a state is equal to the product of each of the hourly integrated bus LMPs and hourly integrated load for each load bus in a state, summed across every hour of the year, divided by the sum of the hourly integrated bus loads at each load bus in that state for each hour in the year.

Day Ahead

The system day-ahead, load-weighted, average LMP for an hour is equal to the sum of the product of the hourly LMP at each load bus and the corresponding nodal, total day-ahead hourly load at each load bus in the system, divided by the sum of the nodal, total day-ahead hourly loads across the buses.

The zonal day-ahead, load-weighted, average LMP for an hour is equal to the sum of the product of the hourly bus LMPs for each load bus in a zone and the hourly estimated load distribution factors for each load bus in that zone. The zonal day-ahead, load-weighted, average LMP does not use the full nodal, total day-ahead hourly loads used in the other calculations of day-ahead average LMP.

The day-ahead, load-weighted, average LMP for an hour for a state is equal to the sum of the product of the hourly bus LMPs for each load bus in a state and the hourly factor distributed load, from each contributing zone, for each load bus in that state. The state specific day-ahead, load-weighted, average LMP does not use the full nodal, total day-ahead hourly loads used in the other calculations of day-ahead average LMP.

The system day-ahead, load-weighted, average LMP for a day is equal to the product of the hourly day-ahead LMPs for each load bus and the nodal, total hourly day-ahead load for each load bus, for each hour, summed over every hour of the day, divided by the sum of the nodal, total hourly day-ahead loads for the system for the day.

The zonal day-ahead, load-weighted, average LMP for a day is equal to the product of each of the hourly day-ahead LMPs for each load bus in a zone and the hourly estimated load distribution factors for each load bus in that zone and the hourly day-ahead load for the zone, summed over every hour of the day, and divided by the corresponding estimated total zonal load for the day. The zonal day-ahead, load-weighted, average LMP does not use the full nodal, total day-ahead hourly loads used in the other calculations of day-ahead average LMP.

The day-ahead, load-weighted, average LMP for a day for a state is equal to the product of each of the hourly day-ahead LMPs for each load bus in a state and the hourly factor distributed load, from each contributing zone, for each load bus in that state, summed over every hour of the day, and divided by the corresponding estimated total hourly factor distributed load for the day. The zonal day-ahead, load-weighted, average LMP does not use the full nodal, total day-ahead hourly loads used in the other calculations of day-ahead average LMP.

The system day-ahead, load-weighted, average LMP for a year is equal to the product of the hourly LMPs and nodal, total hourly load for each load bus, summed across every hour of the year, divided by the sum of the nodal, total hourly bus loads at each load bus in the system for each hour in the year.

The zonal day-ahead, load-weighted, average LMP for a year is equal to the product of each of the hourly LMPs for each load bus in a zone and the hourly estimated load distribution factors for each load bus in that zone and the hourly day-ahead load for the zone, summed over every hour of the year, and divided by the total estimated zonal load for the year. The zonal day-ahead, load-weighted, average LMP does not use the full nodal, total day-ahead hourly loads used in the other calculations of day-ahead average LMP.

The day-ahead, load-weighted, average LMP for a year for a state is equal to the product of each of the hourly LMPs for each load bus in a zone and the hourly factor distributed load, from each contributing zone, for each load bus in that state, summed over every hour of the year, and divided by the corresponding estimated total hourly factor distributed load for the year. The zonal day-ahead, load-weighted, average LMP does not use the full nodal, total day-ahead hourly loads used in the other calculations of day-ahead average LMP.

Equation H-1 LMP calculations

	i = 5-minute interval	h = 12 intervals = hour i = 1..12	d = 24 hours = day h = 1..24	y = 365 days = 8,760 hours = year d = 1..365
Bus average	LMP_{bi}	$LMP_{bh}=\frac{\sum_{i=1}^{12} LMP_{bi}}{12}$	$LMP_{bd}=\frac{\sum_{h=1}^{24} LMP_{bh}}{24}$	$LMP_{by}=\frac{\sum_{h=1}^{8760} LMP_{bh}}{8760}$
Bus load-weighted average			$lwLMP_{bd}=\frac{\sum_{h=1}^{24}(LMP_{bh}\bullet Load_{bh})}{\sum_{h=1}^{24} Load_{bh}}$	$lwLMP_{by}=\frac{\sum_{h=1}^{8760}(LMP_{bh}\bullet Load_{bh})}{\sum_{h=1}^{8760} Load_{bh}}$
System average	$LMP_{si}=\frac{\sum_{b=1}^{B} LMP_{bi}}{B}$	$LMP_{sh}=\frac{\sum_{b=1}^{B} LMP_{bh}}{B}$	$LMP_{sd}=\frac{\sum_{h=1}^{24}\frac{\sum_{b=1}^{B}(LMP_{bh}\bullet Load_{bh})}{\sum_{b=1}^{B} Load_{bh}}}{24}$	$LMP_{sy}=\frac{\sum_{h=1}^{8760}\frac{\sum_{b=1}^{B}(LMP_{bh}\bullet Load_{bh})}{\sum_{b=1}^{B} Load_{bh}}}{8760}$
System load-weighted average	$lwLMP_{si}=\frac{\sum_{b=1}^{B}(LMP_{bi}\bullet Load_{bi})}{\sum_{b=1}^{B} Load_{bi}}$	$lwLMP_{sh}=\frac{\sum_{b=1}^{B}(LMP_{bh}\bullet Load_{bh})}{\sum_{b=1}^{B} Load_{bh}}$	$lwLMP_{sd}=\frac{\sum_{h=1}^{24}\sum_{b=1}^{B}(LMP_{bh}\bullet Load_{bh})}{\sum_{h=1}^{24}\sum_{b=1}^{B} Load_{bh}}$	$lwLMP_{sy}=\frac{\sum_{h=1}^{8760}\sum_{b=1}^{B}(LMP_{bh}\bullet Load_{bh})}{\sum_{h=1}^{8760}\sum_{b=1}^{B} Load_{bh}}$

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APPENDIX I – LOAD DEFINITIONS

PJM measures load in a number of ways. The Market Monitoring Unit (MMU) makes use of two fundamental measures of load in its analysis of the PJM market: eMTR load and accounting load. In the 2008 State of the Market Report, both measures of load are used, as appropriate for the specific analysis. The measures of load and their applications changed after PJM's June 1, 2007, implementation of marginal losses.

eMTR Load

PJM uses eMTR load to measure peak loads and as the basis for accounting load determinations. eMTR load is supplied by PJM electricity distribution companies (EDCs) and generators and is based on the metered MWh values of tie lines and the metered values of generation MWh. For PJM Western Region and Southern Region EDCs (ComEd, AEP, DAY, DLCO, AP and Dominion), eMTR load values inherently include local, EHV (extra-high-voltage) and non-EHV losses. eMTR load values for PJM Mid-Atlantic Region EDCs inherently include local and non-EHV losses plus an allocation of metered Mid-Atlantic Region EHV losses.

eMTR load is used in state of the market reports to measure peak load. This is the total amount of generation output and net energy imports required to meet the peak load on the system, including losses.

Accounting Load

PJM uses accounting load in the settlement process. Prior to June 1, 2007, accounting load for all EDCs was equal to eMTR load. In other words, prior to June 1, 2007, accounting load included losses. Since the implementation of marginal losses on June 1, 2007, two types of accounting load have been calculated: accounting load with losses and accounting load without losses. Accounting load, without losses, for Western Region and Southern Region EDCs is calculated by subtracting non-EHV and EHV losses from eMTR load. Accounting load, without losses, for Mid-Atlantic Region EDCs is calculated by subtracting non-EHV losses and the EHV loss allocations from eMTR load. Since June 1, 2007, accounting load without losses has represented the actual retail customer load and is referred to here as accounting load.

Accounting load is used in the *2008 State of the Market Report* to measure daily, monthly and annual load. Accounting load is also used in the *2008 State of the Market Report* to weight LMP in load-weighted LMP calculations. Prior to June 1, 2007, accounting load includes losses and after June 1 accounting load excludes losses. Prior to June 1, 2007, LMP did not include losses. After June 1, 2007, LMP included losses.

APPENDIX J – MARGINAL LOSSES

On June 1, 2007, PJM revised its methodology for determining transmission losses from average losses to nodal, marginal losses. Marginal loss pricing is based on the incremental losses that result from an increase in output. Marginal loss pricing is designed to permit more efficient system dispatch and decreased total production cost.

Under the new methodology, PJM's locational marginal price (LMP) at a bus *i* is comprised of three distinct components: system marginal price (SMP), marginal losses component of LMP at bus *i* (L_i) and the congestion component of LMP at bus *i* ($CLMP_i$).

Equation J-1 shows the components of LMP at bus *i*.

Equation J-1 LMP components

$$LMP_i = SMP + L_i + CLMP_i$$

SMP is calculated at the distributed load reference bus, where the loss and CLMP contribution to LMP are zero. The LMP at bus *i* is comprised of losses and congestion affects, either positive or negative, that are determined by the bus's location on the system relative to the SMP at the load weighted reference bus.

Total, Average and Marginal Losses

Total transmission losses are equal the product of the square of the current flowing across the line (*I*) and the resistance of the line (*R*). The materials constituting the conductors and other elements of the transmission system exhibit a characteristic impedance to the flow of power. Total transmission losses over a line can also be expressed as the product of the resistance of the line (*R*) times the square of the power consumed by the load (*P*), divided by the square of the voltage (*V*).[1] While this relationship differs somewhat in an alternating current (AC) as compared to a direct current (DC) system, the magnitude of losses can be approximated by the equation:

Equation J-2 Total transmission losses

Total Losses = $I^2 \cdot R = (P^2 \cdot R) / V^2$,

Defining $a = R / V^2$ and substituting into Equation J-2 results in:

Equation J-3 Total transmission losses

Total Losses = $a \cdot P^2$.

Average transmission losses per MW from a given power flow *P* across a transmission element are:

1 Equation J-2 incorporates the substitution of the relationship *I=P/V*, derived from Ohm's Law, for the variable *I*.

Equation J-4 Average transmission losses

$$\text{Average Losses} = \left(a \cdot P^2 / P\right) = a \cdot P.$$

Marginal transmission losses are the incremental losses resulting from an increase in power flow P across the transmission element and are equal to the first derivative of total losses with respect to power flow P:

Equation J-5 Marginal losses

$$\text{Marginal Losses} = \frac{d}{dP}\left(a \cdot P^2\right) = 2 \cdot a \cdot P.$$

For a given power flow P, the marginal losses for an increase in P are, therefore, equal to twice the average losses for the associated total flow P.

Effect of Marginal Losses on LMP

The following equations illustrate the effect of marginal losses on least cost dispatch. In this simple example, the least cost dispatch problem involves meeting system load and the losses associated with serving that load.

Equation J-6 defines the total cost of generation (C_T), which is a function of generator output (P) of units i though N.

Equation J-6 Total cost of generation

$$C_T = \sum_{i=1}^{N}\left[C_i(P_i)\right]$$

Equation J-7 is the power balance constraint, where total injections ($\sum_{i}^{N} P_i$) must equal total withdrawals (P_{load}) plus total losses (P_{loss}), where losses are a function of ($\sum_{i}^{N} P_i$).

Equation J-7 Power Balance Constraint

$$P_{load} + P_{loss}\left(\sum_{i=1}^{N} P_i\right) = \sum_{i=1}^{N} P_i$$

Together, equation Equation J-6 and Equation J-7 form a system of equations which can be represented by a Lagrangian (ζ), as defined in Equation J-8.

Equation J-8 System

$$\zeta(P_i) = \sum_{i=1}^{N} C_i(P_i) + \lambda_i \bullet (P_{load} + P_{loss}(\sum_{i}^{N} P_i) - \sum_{i=1}^{N} P_i)$$

Optimizing Equation J-8 for $P_{i...n}$ results in Equation J-9 and Equation J-7:

Equation J-9 Lambda

$$\frac{dC}{dP_i} \bullet \frac{1}{(1 - \frac{dP_{loss}}{dP_i})} = \lambda_i$$

Equation J-10 Power Balance Constraint (from above)

$$P_{load} + P_{loss}\left(\sum_{i=1}^{N} P_i\right) = \sum_{i=1}^{N} P_i$$

Note, that Equation J-9 shows that the optimal dispatch of each generator *i* must account for losses associated with using that unit to meet load. This measure of losses is the marginal loss penalty factor (Pf_f) for incremental power from generator *i* to serve system load:

Equation J-11 Penalty factor

$$Pf_i = \frac{1}{\left(1 - \frac{\partial P_{loss}}{\partial P_i}\right)}.$$

The incremental cost of using output from generator *i* to meet load includes incremental losses.[2]

The term $\frac{\partial P_{loss}}{\partial P_i}$ is called the loss factor and represents the change in system losses for a change in output from generator *i* to meet load.

If an increase in power from generator *i* results in an incremental increase in losses, then the loss factor is positive:

$$0 < \frac{\partial P_{loss}}{\partial P_i} < 1,$$

and the resultant penalty factor at bus_i would be greater than one:

$$Pf_i = \frac{1}{\left(1 - \frac{\partial P_{loss}}{\partial P_i}\right)} > 1.$$

Conversely, if an increase in power results in a decrease in losses, then the loss factor is negative:

$$-1 < \frac{\partial P_{loss}}{\partial P_i} < 0,$$

and the resultant penalty factor at bus *i* would be less than one: $Pf_i = \frac{1}{\left(1 - \frac{\partial P_{loss}}{\partial P_i}\right)} < 1$.

2 Note, as presented here, the marginal effect is on total losses, not losses at any particular load bus.

The unit offer curve of a generator is multiplied by the respective penalty factor for serving the load. (See Equation J-11) To the system operator, seeking to minimize the costs of serving a given level of load, the existence of losses modifies the relative costs of output from the unit relative to the case where losses are not accounted for. If the relevant penalty factor is greater than one, system losses would be made greater by increasing the output of that generator to serve load, and the unit offer curve, from the system operator perspective, would be shifted upward relative to the case where losses were not accounted for. Similarly, if the penalty factor associated with generator i delivering power to load is less than one, system losses associated with serving system load would be reduced by increasing the output of generator *i* , and the unit offer curve would shift downward relative to the case where losses are not accounted for.

These marginal loss related adjustments in relative costs will affect the optimal dispatch, and the resulting LMPs, for any given level of load relative to the case where marginal losses are not accounted for. LMPs at specific load buses will reflect the fact that marginal generators must produce more (or less) energy due to losses to serve that bus than is needed to serve the load weighted reference bus. The LMP at any bus is a function of the SMP, losses and congestion. Relative to the system marginal price (SMP) at the load weighted reference bus, the loss factor can be either positive or negative.

Loss Revenue Surplus

As demonstrated in Equation J-5, revenues resulting from marginal losses are approximately twice those collected from average losses. As demonstrated in Equation J-2, losses are equal to the square of the power, *P.* As such, two loads of equal size at the same location, served simultaneously, result in losses four times greater than the losses incurred in serving either of them separately. By utilizing the penalty factor in the dispatch, losses are paid based on marginal losses rather than based on average losses. Other than the effect on the optimal dispatch point, LMP at the marginal generator bus, and therefore the payment to the generator, is not affected. By paying for losses based on marginal instead of average losses at the load bus, arevenue over collection occurs. Using the example of two loads, of equal size at the same location, being served simultaneously, the marginal losses associated with the combined effect of the loads are greater than the sum of the losses incurred by each load separately, thus resulting in an over collection.

Properly accounting for marginal losses allows for an optimal, least cost solution to the system of equations that make up the market to serve load. Over collection is a direct outcome of marginal cost pricing and not a cause for concern. Prices set on this basis reflect the true incremental cost of serving load at any bus, and provide efficient incremental resource signals. Of concern under these circumstances is what is done with the over collection and how it is distributed among the market participants. These disbursements should be provided to the market participants that pay for the marginal losses in their energy charges, in this case the loads. To maintain an efficient price signal, any reallocation of the excess revenues must not interfere with the price signal at the margin. The solution to this problem generally takes the form of lump sum payments to market participants. The next issue is how to distribute the payments among the loads. To the extent that the causality of total marginal losses related costs are not generally directly attributable to specific load serving entities, the actual allocation methodology used to distribute the lump sum payments, while important from a policy perspective, is more a question of equity than market outcome efficiency. Under these circumstances, where there are common costs attributable to providing a service to a number of parties, it is general accepted practice to allocate the common costs, or benefits, to participants in proportion to their contribution to total load. This is the approach adopted by PJM. Under PJM's tariff, excess total loss related revenues are allocated to transmission users based on load plus export ratio shares:

Equation J-12 Excess loss revenue allocation

$$\text{Loss Credit} = (\text{Total Loss Surplus}) + \left(\frac{\text{Customer total MWh delivered to load} \ + \ \text{exports}}{\text{Total PJM MWh delivered to load} \ + \ \text{exports}}\right).$$

APPENDIX K – CALCULATION AND USE OF GENERATOR SENSITIVITY/ UNIT PARTICIPATION FACTORS

Sensitivity factors define the impact of each marginal unit on locational marginal price (LMP) at every bus on the system. The availability of sensitivity factor data permits the refinement of analyses in areas where the goal is to calculate the impact of unit characteristics or behavior on LMP.[1] These factors include the impact on LMP of the cost of fuel by type, the cost of emissions allowances by type, frequently mitigated unit adders and unit markup by unit characteristics.[2]

Generator sensitivity factors, or unit participation factors (UPFs), are calculated within the least-cost, security-constrained optimization program. For every five-minute system solution, UPFs describe the incremental amount of output that would have to be provided by each of the current set of marginal units to meet the next increment of load at a specified bus while maintaining total system energy balance. A UPF is calculated from each marginal unit to each load bus for every five-minute interval. In the absence of marginal losses, the UPFs associated with the set of marginal units in any given interval, for a particular load bus, always sum to 1.0. UPFs can be either positive or negative. A negative UPF for a unit with respect to a specific load bus indicates that the unit would have to be backed down for the system to meet the incremental load at the load bus.

Within the context of a security-constrained, least-cost dispatch solution for an interval, during which the LMP at the marginal unit's bus equals the marginal unit's offer, consistent with its output level, LMP at each load bus is equal to each marginal unit's offer price, multiplied by its UPF, relative to that load bus. In some cases, the bus price for the marginal unit may not equal the calculated price based on the offer curve of the marginal unit. These differences are the result of unit dispatch constraints, transmission constraints and the interactions among them. Any difference between the price based on the offer curve and the actual bus price is categorized as "constrained off." In addition, final LMPs calculated using UPFs may differ slightly from PJM's posted LMPs as a result of rounding and missing data. Such differentials are identified as not available (NA).

Table K-1 shows the relationship between marginal generator offers and the LMP at a specific load bus X in a given five-minute interval.

Table K-1 LMP at bus X

Generator	UPF Bus X	Offer	Generator Contribution to LMP at X	Generator Contribution to LMP at X (Percentage)
A	0.5	$200.00	$100.00	85%
B	0.4	$40.00	$16.00	14%
C	0.1	$10.00	$1.00	1%
			LMP at X	
			$117.00	100%

1 The PJM Market Monitoring Unit (MMU) identified applications for sensitivity factors and began to save sensitivity factors in 2006.

2 Before the *2006 State of the Market Report*, state of the market reports had shown the impact of each marginal unit on load and on LMP based on engineering estimates whenever there were multiple marginal units.

Table K-1 shows three hypothetical, marginal generators at three different buses (A, B and C); each affects LMP at load bus X. Each generator's effect on LMP at X is measured by the UPF of that unit with respect to X. The UPF for generator A is 0.5 relative to load bus X, meaning that 50 percent of marginal Unit A's offer price contributes directly to the LMP at X. Since A has an offer price of $200, generator A contributes $100, or UPF times the offer, to the LMP at load bus X. The UPFs from all the marginal units to the load bus must sum to 1.0, so that the marginal units explain 100 percent of the load bus LMP. Generators B and C have UPFs of 0.4 and 0.1, respectively, and offer prices of $40 and $10, respectively, and therefore contribute $16 and $1, respectively, to the LMP at X. Together, the marginal units' offers multiplied by their UPFs with respect to load bus X explain the interval LMP at the load bus.

Hourly Integrated LMP Using UPF

Table K-1 describes the relationship between LMP and UPFs for a five-minute interval. Since PJM charges loads and credits generators on the basis of hourly integrated LMP, the relationship among marginal unit offers, UPFs and the hourly integrated LMP must be specified.

The relevant variables and notation are defined as follows:

h = hour,

i = five-minute interval,

t = year, where t designates the current year and t-1 designates the previous year,

b = a specified load bus, where b ranges from 1 to B,

g = a specified marginal generator, where g ranges from 1 to G, and

L = interval-specific load.

The hourly integrated load at a bus is the simple average of the 12 interval loads at a bus in a given hour:

Equation K-1 Hourly integrated load at a bus

$$Load_{bh} = \frac{\sum_{i=1}^{12} L_{bi}}{12}.$$

Load bus *LMP* is determined on a five-minute basis and is a function of marginal unit offers and *UPF*s in that interval:

Equation K-2 Load bus LMP

$$LMP_{bi} = \sum_{g=1}^{G} \left(Offer_{gi} \bullet UPF_{gbi}\right).$$

The hourly integrated *LMP* at a bus is the simple average of the 12 interval LMPs at a bus in a given hour:

Equation K-3 Hourly integrated LMP at a bus

$$LMP_{bh} = \frac{\sum_{i=1}^{12} LMP_{bi}}{12}.$$

Total cost (*TC*) of the system in the hour is equal to the product of the hourly integrated LMP and the hourly integrated load at each bus summed across all buses in the hour:

Equation K-4 Hourly total system cost

$$TC_h = \sum_{b=1}^{B} \left(LMP_{bh} \bullet Load_{bh} \right).$$

System load-weighted LMP for the hour ($LMPSYS_h$) is equal to the total hourly system cost (*TC*) divided by the sum of a bus's simple 12 interval average loads in the hour:

Equation K-5 Hourly load-weighted LMP

$$LMPSYS_h = \frac{TC_h}{\sum_{b=1}^{B} Load_{bh}}.$$

The system annual, load-weighted, average (S*LW*) LMP for the year is:

Equation K-6 System annual, load-weighted, average LMP

$$Annual\_SLW\_LMP = \sum_{h=1}^{8760} \frac{TC_h}{\sum_{b=1}^{B} Load_{bh}}.$$

Hourly Integrated Markup Using UPFs

Markup is defined as the difference between the price from the price-based offer curve and the cost from the cost-based offer curve at the operating point of a specific marginal unit. UPFs can be used to calculate the impact of marginal unit markup behavior on the LMP at any individual load bus and of the LMP at any aggregation of load buses including the system LMP. The resultant markup component of LMP is a measure of market power, a market performance metric. The markup component of LMP is based on the markup of the actual marginal units and is not based on a redispatch of the system using cost-based offers.

To determine the impact of marginal unit markup behavior on system LMP on an hourly integrated basis, the following steps are required.

Total cost (*TC*) of the system in the hour is equal to the product of the average LMP and the average load at each bus summed across all buses in the hour which, using the definitions above, can be expressed in terms of marginal unit offers and UPFs:

Equation K-7 UPF-based system hourly total cost

$$TC_h = \sum_{b=1}^{B} \left(LMP_{bh} \bullet Load_{bh}\right) = \sum_{b=1}^{B} \left[Load_{bh} \bullet \frac{\sum_{i=1}^{12} \sum_{g=1}^{G} \left(Offer_{gi} \bullet UPF_{gbi}\right)}{12} \right].$$

System load-weighted LMP for the hour is equal to total hourly system cost divided by the sum of the bus's simple 12 interval average loads in the hour:

Equation K-8 System load-weighted LMP

$$LMPSYS_h = \frac{TC_h}{\sum_{b=1}^{B} Load_{bh}} = \frac{\sum_{b=1}^{B} \left[Load_{bh} \bullet \frac{\sum_{i=1}^{12} \sum_{g=1}^{G} \left(Offer_{gi} \bullet UPF_{gbi}\right)}{12} \right]}{\sum_{b=1}^{B} Load_{bh}}.$$

Holding dispatch and marginal units constant, the system, hourly load-weighted LMP based on cost offers of the marginal units, shown in Equation K-9, is found by substituting the marginal unit cost offers into Equation K-8**:**

Equation K-9 Cost-based offer system, hourly load-weighted LMP

$$LMPSYSCost_h = \frac{TC_h}{\sum_{b=1}^{B} Load_{bh}} = \frac{\sum_{b=1}^{B} \left[Load_{bh} \bullet \frac{\sum_{i=1}^{12} \sum_{g=1}^{G} \left(CostOffer_{gi} \bullet UPF_{gbi}\right)}{12} \right]}{\sum_{b=1}^{B} Load_{bh}}.$$

The contribution of the markup by marginal units to system LMP for the hour is shown in Equation K-10 below:

Equation K-10 Impact of marginal unit markup on LMP

$$MarkUp_h = LMPSYS_h - LMPSYSCost_h.$$

UPF–Weighted, Marginal Unit Markup

The price-cost markup index for a marginal unit provides a measure of market power based on the behavior of a single unit of an individual generator:

Equation K-11 Price-cost markup index

$$MarkUp_{gi} = \frac{Offer_{gi} - CostOffer_{gi}}{Offer_{gi}}.$$

The UPF load-weighted, marginal unit markup (measure of unit behavior) provides a measure of market power for a given hour for the system or any aggregation of load buses. This measure of system performance equals the weighted-average markup index for all marginal units, which is a measure of unit behavior:

Equation K-12 UPF load-weighted, marginal unit markup

$$lwMarkUp_h = \frac{\sum_{b=1}^{B}\left[\frac{\sum_{i=1}^{12}\sum_{g=1}^{G}\left(MarkUp_{gi} \bullet UPF_{gbi}\right)}{12} \bullet Load_{bh}\right]}{\sum_{b=1}^{B} Load_{bh}}.$$

Hourly Integrated Historical, Cost-Adjusted, Load-Weighted LMP Using UPFs

UPFs can be used to calculate historical, cost-adjusted, load-weighted LMP for a specific time period. This method is used to disaggregate the various components of LMP, including all the separate components of unit marginal cost and unit markup, and to calculate the contributions of each component to system LMP.

The extent to which fuel cost, emission allowance cost, variable operation and maintenance cost (VOM) and markup affect the offers of marginal units depends on the share of the offer that each component represents. The percentage of a unit's offer that is based on each of the components is given as the following:

Fuel:	$\%Fuel_{gi}$
SO_2:	$\%SO_{2\,gi}$
NO_x:	$\%NO_{x\,gi}$
VOM:	$\%VOM_{gi}$
Markup:	$\%MarkUp_{gi}$

The proportion of specific components of unit offers is calculated on an interval and on a unit-specific basis. Cost components are determined for each marginal unit for the relevant time periods:

Delivered fuel cost per MWh: FC_{gt}.

Sulfur dioxide, emission-related cost per MWh: $SO_{2\,gt}$.

Nitrogen oxide, emission-related cost per MWh: $NO_{x\,gt}$.

Fuel costs (*FC)* are specific to the unit's location, the unit's fuel type and the time period in question. For example:

FC_{gt} = Avg *FC* in specified "Current Year's Period" (e.g., April 1, 2008); and

FC_{gt-1} = Avg *FC* in specified "Previous Year's Period" (e.g., April 1, 2007).

Fuel-Cost-Adjusted LMP

The portion of a marginal generator's offer that is related to fuel costs for a specified period is adjusted to reflect the previous period's fuel costs. Subtracting the proportional fuel-cost adjustment from the marginal generator's interval-specific offer provides the fuel-cost-adjusted offer (*FCA)*:

Equation K-13 Fuel-cost-adjusted offer

$$FCAOffer_{gi} = Offer_{gi} \bullet \left[1 - \%Fuel_{gi} \bullet \left(\frac{FC_{gt} - FC_{gt-1}}{FC_{gt}} \right) \right].$$

Using $FCAOffer_{gi}$ for all marginal units in place of the unadjusted offers ($offer_{gi}$) in Equation K-8 (i.e., the system load-weighted LMP equation), results in the hourly fuel-cost-adjusted, load-weighted LMP:

Equation K-14 Fuel-cost-adjusted, load-weighted LMP

$$LWFCAsysLMP_h = \frac{TCFCA_h}{\sum_{b=1}^{B} Load_{bh}} = \frac{\sum_{b=1}^{B} \left[Load_{bh} \bullet \frac{\sum_{i=1}^{12} \sum_{g=1}^{G} \left(FCAOffer_{gi} \bullet UPF_{gbi} \right)}{12} \right]}{\sum_{b=1}^{B} Load_{bh}}.$$

The systemwide annual, fuel-cost-adjusted, load-weighted (*SFCALW*) LMP for the year is given by the following equation:

Equation K-15 Systemwide annual, fuel-cost-adjusted, load-weighted LMP

$$Annual\_SFCALW\_LMP = \sum_{h=1}^{8760} \frac{TCFCA_h}{\sum_{b=1}^{B} Load_{bh}}.$$

Cost-Adjusted LMP

Summing the unit's specific historical, cost-adjusted component effects and subtracting that sum from the unit's unadjusted offer provides the historical, cost-adjusted offer of the unit (*HCAOffer*):

Equation K-16 Unit historical, cost-adjusted offer

$$HCAOffer_{gi} = Offer_{gi} \bullet \left[1 - \%Fuel_{gi} \bullet \left(\frac{FC_{gt} - FC_{gt-1}}{FC_{gt}}\right) - \%NOx_{gi} \bullet \left(\frac{NOx_{gt} - NOx_{gt-1}}{NOx_{gt}}\right) - \%SO2_{gi} \bullet \left(\frac{SO2_{gt} - SO2_{gt-1}}{SO2_{gt}}\right)\right].$$

Using each unit's $HCAOffer_{gi}$ in place of its unadjusted offers ($offer_{gi}$) in Equation K-8 (i.e., the system load-weighted LMP equation) results in the following historical, cost-adjusted, load-weighted LMP for the hour in question:

Equation K-17 Unit historical, cost-adjusted, load-weighted LMP

$$LWHCAsysLMP_h = \frac{TCHCA_h}{\sum_{b=1}^{B} Load_{bh}} = \frac{\sum_{b=1}^{B}\left[Load_{bh} \bullet \frac{\sum_{i=1}^{12}\sum_{g=1}^{G}\left(HCAOffer_{gi} \bullet UPF_{gbi}\right)}{12}\right]}{\sum_{b=1}^{B} Load_{bh}}.$$

The annual systemwide, historical, cost-adjusted, load-weighted (*annual SHCALW*) LMP for the year is given by the following equation:

Equation K-18 Systemwide, historical, cost-adjusted, load-weighted LMP

$$Annual\_SHCALW\_LMP = \sum_{h=1}^{8760} \frac{TCHCA_h}{\sum_{b=1}^{B} Load_{bh}}.$$

Components of LMP

Table K-2 Components of PJM annual, load-weighted, average LMP: Calendar year 2008

Element	Contribution to LMP	Percent
Gas	$36.03	50.7%
Coal	$26.44	37.2%
Oil	$2.56	3.6%
Uranium	$0.00	0.0%
FMU Adder	$0.30	0.4%
SO2	$1.80	2.5%
NOX	$0.72	1.0%
VOM	$3.00	4.2%
Markup	$2.04	2.9%
Offline CT Adder	$0.34	0.5%
UDS Override Differential	($1.79)	(2.5%)
Dipatch Differential	$0.03	0.0%
Small DFAX adjustment	($0.20)	(0.3%)
Flow violation adjustment	$0.01	0.0%
Unit LMP Differential	($0.27)	(0.4%)
NA	$0.12	0.2%
LMP	$71.13	100.0%

There are several components of LMP that are not directly a function of individual unit characteristics:

— **Offline CT Adder.** Offline CTs that are marginal in the UDS solution have $3 added to their operational offer. This is reflected at the CT unit bus and is propagated through the UDS system solution to the LPA marginal unit buses.

The offline CT adder is the contribution of this process to annual average, load weighted LMP.

— **UDS Override Differential.** The LPA preprocessor determines the set of units eligible to set price in the LPA solution every five minutes. In order to determine eligible units, the preprocessor takes input from UDS in the form of desired MW, unit specific dispatch rates (UDS LMP), zonal dispatch rates, and unit operating limits. The preprocessor evaluates each unit against several thresholds designed to measure the extent to which units are currently following the dispatch signals provided by UDS. Units are eligible to set price in the LPA if they meet all the criteria in the preprocessor. A unit's current offer is calculated based on the unit's offer curve and the current state estimated solution. If a unit is following dispatch and its offer is less than the UDS LMP, the unit is eligible to set price based on its current offer. If a unit's current offer is greater than the UDS LMP and the unit is not a CT, the unit's current offer is overridden with the UDS LMP. When overridden, the unit's current offer becomes the

UDS LMP and the unit is again eligible to set price, based on the UDS LMP. The UDS LMP does not reflect the unit's offer curve and does not represent the offer behavior of the units whose offers are overridden.

The UDS LMP is the dispatch rate calculated based on where units may be operating in the future, e.g. 18 minutes. The UDS LMP is calculated respecting all transmission and operating constraints and is calculated based on a set of marginal units in the UDS solution. These marginal units set the UDS LMP in UDS in the same way that the LPA marginal units set the LMP. However, when a UDS override occurs, the UDS solution marginal units have a direct effect on the LPA marginal prices.

At the LPA marginal unit bus, the UDS override differential is calculated as the difference between the UDS determined LPA marginal unit bus price and the actual LPA marginal unit bus price. The UDS override differential is the contribution of these differentials to annual average, load weighted LMP.

— **Dispatch Differential.** Measures any difference between the bus LMP and the LPA operational offer. The dispatch differential is the contribution of this difference to the annual average, load weighted LMP.

— **Small DFAX adjustment.** Marginal units with DFAX to a constraint less than 1.0 percent are excluded from contributing to the solution of the constraint. The system solution resulting from the exclusion is used to determine the congestion component of that constraint to buses with a DFAX less than 1.0 percent. The small DFAX adjustment is the contribution of this difference to the annual average, load weighted LMP.

— **Flow violation adjustment.** When the flow on a constraint is allowed to exceed its rating and a marginal unit is not identified, resource constraints are treated as a virtual resource in the least cost dispatch solution. The marginal cost of using this resource is equal to the constraint violation penalty value for the constraint. The resulting shadow price of the constraint is reflected at every bus based on the DFAX of each bus relative to the violated constraint. The flow violation adjustment is the contribution of this adjustment to the annual average, load weighted LMP.

— **Unit LMP differential.** Where the product of the UDS UPFs and UDS marginal unit operational offers does not equal the LPA marginal unit bus LMP, this component measures that difference. The unit LMP differential is the contribution of this difference to the annual average, load weighted LMP.

— **NA.** NA is the net difference between the load weighted LMP based on the LPA marginal bus price and associated UPFs and the load weighted accounting LMP. NA is the contribution of this difference to the annual average, load weighted LMP.

APPENDIX L – THREE PIVOTAL SUPPLIER TEST

PJM markets are designed to promote competitive outcomes. Market design is the primary means of achieving and promoting competitive outcomes in the PJM markets. One of the Market Monitoring Unit's (MMU's) primary goals is to identify actual or potential market design flaws.[1] PJM's market power mitigation goals have focused on market designs that promote competition (i.e., a structural basis for competitive outcomes) and on limiting market power mitigation to instances where market structure is not competitive and thus where market design alone cannot mitigate market power. In the PJM Energy Market, this occurs only 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.

The structural test for implementing offer capping set forth in the PJM Amended and Restated Operating Agreement (OA) Schedule 1, Sections 6.4.1(e) and (f) is the three pivotal supplier test. The three pivotal supplier test is applied by PJM on an ongoing basis in order to determine whether offer capping is required for any transmission constraint. The three pivotal supplier test defined in the OA represents a significant evolution in accuracy because the test is applied in real time using the actual data used by the dispatchers to dispatch the system including transmission constraints and the real-time details of incremental generator availability.

As a result of PJM's implementation of the three pivotal supplier test in real time, the actual competitive conditions associated with each binding constraint are analyzed in real time as they arise. The three pivotal supplier test replaced the prior approach which was to offer cap all units required to resolve a binding constraint. The application of the three pivotal supplier test has meant a reduction in the application of offer capping. As a result of the application of the three pivotal supplier test, offer capping is applied only at times when the local market structure is not competitive and only to those participants with structural market power.

Three Pivotal Supplier Test: Background

By order issued April 18, 2005, the United States Federal Energy Regulatory Commission (FERC) set for hearing, in Docket No. EL04-121-000, PJM's proposal: a) to exempt the AP South Interface from PJM's offer-capping rules; and b) to conduct annual competitive analyses to determine whether additional exemptions from offer capping are warranted. By order issued July 5, 2005, the FERC also set for hearing, in Docket No. EL03-236-006, PJM's three pivotal supplier test. The Commission further set for hearing issues related to the appropriateness of implementing scarcity pricing in PJM. In the July order, the Commission consolidated Docket No. EL04-121-000 and Docket No. EL03-236-006.

On November 16, 2005, PJM filed a "Settlement Agreement" resolving all issues set for hearing in Dockets Nos. EL04-121-000 and ER03-236-006, which included the application of the three pivotal supplier ("TPS") test, provisions for scarcity pricing, offer caps for frequently mitigated units and

1 PJM. "Open Access Transmission Tariff (OATT)," "Attachment M: Market Monitoring Plan," Third Revised Sheet No. 452 (Effective July 17, 2006).

competitive issues associated with certain of PJM's internal interfaces. The Commission approved this settlement on January 27, 2006, and the TPS test was implemented shortly thereafter.[2]

On January 15, 2008 the Maryland Public Service Commission filed a complaint against PJM requesting that the Commission remove PJM's market rule provisions that exempt certain generation resources from energy offer price mitigation and that the Commission initiate an investigation to determine whether generators exempt from mitigation have exercised market power and provide retroactive relief where appropriate. By order issued May 16, 2008, the Commission granted the request to remove the mitigation exemptions, but also established a Section 206 investigation and paper hearing in Docket No. EL08-47-000 to consider the justness and reasonableness of PJM's the mitigation program adopted in settlement ("May 16th Order").[3] The hearing was held in abeyance pending the earlier of either the conclusion of the ongoing stakeholder process conducted primarily in the Three Pivotal Supplier Task Force convened to evaluate the performance of the TPS test and its potential application to the Regulation Market.

PJM filed a report on the status of stakeholder progress on the issue on September 5, 2008, explaining that no consensus had been reached, but that the process had provided stakeholders a greater understanding of the theory behind and the implementation of the TPS test. PJM declined to propose any revisions to the TPS test.

On October 6, 2008, numerous parties including the MMU filed comments on the merits of the TPS test and alternatives. A smaller group filed reply comments on November 5, 2008. The MMU filed on November 25, 2008 a supplemental response.

On February 2, 2009, the Commission issued an initial order in its investigation finding that "there is not sufficient evidence to meet the Federal Power Act section 206 burden to show that the three-pivotal-supplier test … is unjust and unreasonable as it relates to assessing the structural competitiveness of the PJM energy market."[4] The Commission, however, found that "because default bids do not clearly and explicitly provide for the inclusion of opportunity costs, especially for energy and environmentally-limited resources, the mitigation measures related to determining default bids are unjust and unreasonable."[5] The Commission, therefore, required PJM "to make a compliance filing that proposes an approach for addressing the incorporation of opportunity costs in mitigated offers" on or before July 31, 2009.[6] The Commission also provided that "within 30 days after that filing, other parties may provide comments on the PJM proposal or submit their own specific proposals for resolving this issue." [7]

Several parties requested rehearing of the May 16th Order, which the Commission denied on December 19, 2008.[8]

On October 1, 2008, in Docket No. ER09-13-000, PJM filed to add the TPS test to the Regulation Market. On October 20, 2008, numerous parties filed comments or protest, including the MMU, which supported PJM's proposal but indicated reservations about certain aspects of its implementation.

2 114 FERC ¶61,076 (2006).
3 123 FERC ¶ 61,169 (2008).
4 *PJM Interconnection, L.L.C.*, 126 FERC ¶ 61,145 at P 1.
5 *Id.* at P 42.
6 *Id.* at P 48.
7 *Id.*
8 125 FERC ¶ 61,340 (2008).

The MMU requested that the Commission direct the MMU to report on those aspects of PJM's proposal. On November 26, 2008, the Commission approved the application of the TPS test to the Regulation Market, directing the MMU to file the requested report by of November 26, 2009.[9]

Market Structure Tests and Market Power Mitigation: Core Concepts

A test for local market power based on the number of pivotal suppliers has a solid basis in economics and is clear and unambiguous to apply in practice. There is no perfect test, but the three pivotal supplier test for local market power strikes a reasonable balance between the requirement to limit extreme structural market power and the goal of limiting intervention in markets when competitive forces are adequate. The three pivotal supplier test for local market power is also a reasonable application of the logic contained in the Commission's market power tests.

The Commission adopted market power screens and tests in the AEP Order.[10] The AEP Order defined two indicative screens and the more dispositive delivered price test. The Commission's delivered price test for market power defines the relevant market as all suppliers who offer at or below the clearing price times 1.05 and, using that definition, applies pivotal supplier, market share and market concentration analyses. These tests are failed if, in the relevant market, the supplier in question is pivotal, has a market share in excess of 20 percent or if the Herfindahl-Hirschman Index (HHI) exceeds 2500. The Commission also recognized that there are interactions among the results of each screen under the delivered price test and that some interpretation is required and, in fact, is encouraged.[11]

The three pivotal supplier test, as implemented, is consistent with the Commission's market power tests, encompassed under the delivered price test. The three pivotal supplier test is an application of the delivered price test to the Real-Time Energy Market, the Day-Ahead Energy Market and the Reliability Pricing Model (RPM) Capacity Market. 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 three pivotal supplier test includes more competitors in its definition of the relevant market than the Commission's delivered price test. While the Commission's delivered price test defines the relevant market to include all offers with costs less than, or equal to, 1.05 times the market price, the three pivotal supplier test includes all offers with costs less than, or equal to, 1.50 times the clearing price for the local market.

The three pivotal supplier test is also consistent with the Commission's delivered price test in that it tests for the interaction between individual participant attributes and features of the relevant market structure. The three pivotal supplier test is an explicit test for the ability to exercise unilateral market power as well as market power via coordinated action, based on economic theory, which accounts simultaneously for market shares and the supply-demand balance in the market.

The results of the three pivotal supplier test can differ from the results of the HHI and market share tests. The three pivotal supplier test can show the existence of structural market power when the HHI is less than 2500 and the maximum market share is less than 20 percent. The three pivotal

9 125 FERC ¶ 61,231(2008).
10 107 FERC ¶ 61,018 (2004) (AEP Order).
11 107 FERC ¶ 61,018 (2004).

supplier test can also show the absence of market power when the HHI is greater than 2500 and the maximum market share is greater than 20 percent. The three pivotal supplier test is more accurate than the HHI and market share tests because it focuses on the relationship between demand and the most significant aspect of the ownership structure of supply available to meet it. A market share in excess of 20 percent does not matter if the holder of that market share is not jointly pivotal and is unlikely to be able to affect the market price. A market share less than 20 percent does not matter if the holder of that market share is jointly pivotal and is likely to be able to affect the market price. Similarly, an HHI in excess of 2500 does not matter if the relevant owners are not jointly pivotal and are unlikely to be able to affect the market price. An HHI less than 2500 does not matter if the relevant owners are jointly pivotal and are likely to be able to affect the market price.[12]

The three pivotal supplier test was designed in light of actual elasticity conditions in load pockets in wholesale power markets in PJM. The price elasticity of demand is a critical variable in determining whether a particular market structure is likely to result in a competitive outcome. A market with a specific set of market structure features is likely to have a competitive outcome under one range of demand elasticity conditions and a noncompetitive outcome under another set of elasticity conditions. It is essential that market power tests account for actual elasticity conditions and that evaluation of market power tests neither ignore elasticity nor make counterfactual elasticity assumptions. As the Commission stated, “In markets with very little demand elasticity, a pivotal supplier could extract significant monopoly rents during peak periods because customers have few, if any, alternatives.”[13] The Commission also stated:

> In both of these models, the lower the demand elasticity, the higher the mark-up over marginal costs. It must be recognized that demand elasticity is extremely small in electricity markets; in other words, because electricity is considered an essential service, the demand for it is not very responsive to price increases. These models illustrate the need for a conservative approach in order to ensure competitive outcomes for customers because many customers lack one of the key protections against market power: demand response.[14]

The Commission defines the relevant market under the delivered price test “by identifying potential suppliers based on market prices, input costs, and transmission availability, and calculates each supplier’s economic capacity for each season/load condition.” The Commission defines the relevant market to include suppliers with “costs less than or equal to 1.05 times the market price,” i.e. those “suppliers that could sell into the destination market at a price less than or equal to 5 percent over the market price.”[15] Thus, the relevant market includes all supply that is potentially competitive with the supplier and excludes supply that is not potentially competitive with the supplier.

The Commission’s market based rates analysis then applies the components of the delivered price test to the relevant market. A supplier fails if the supplier is pivotal (one pivotal supplier test), if it has a market share greater than or equal to 20 percent, or if the HHI in the relevant market is greater than or equal to 2500.[16] A supplier is pivotal under the market power test if demand in the relevant market cannot be met without its supply (one pivotal supplier test).

12 For detailed examples, see Joseph E. Bowring, PJM market monitor. “MMU Analysis of Combined Regulation Market,” PJM Market Implementation Committee Meeting (December 20, 2006).

13 107 FERC ¶ 61,018 (2004).

14 107 FERC ¶ 61,018 (2004).

15 AEP Order at App. F; *see also Inquiry Concerning the Commission’s Merger Policy Under the Federal Power Act: Policy Statement*, Order No. 592, FERC Stats. & Regs. ¶ 31,044, *mimeo* at 6 (1996), reconsideration denied, Order No. 592-A, 79 FERC ¶ 61,321 (1997) (“Merger Policy Statement”); Revised Filing Requirements Under Part 33 of the Commission’s Regulations, Order No. 642, FERC Stats. & Regs. ¶ 31,111 (2000), *order on reh’g*, Order No. 642-A, 94 FERC ¶ 61,289 (2001); Order No. 697 at P 108.

16 Order No. 697 at P 111.

The Commission recognizes the interactions among the multiple analyses under the delivered price test and "encourages the most complete analysis of competitive conditions in the market as the data allow."[17]

For example, passing a single-pivotal supplier test does not demonstrate the absence of structural market power because market participants can coordinate their behavior with other suppliers and can do so without overt interaction. The Commission stated:

> Concentration statistics can indicate the likelihood of coordinated interaction in a market. All else being equal, the higher the HHI, the more firms can extract excess profits from the market. Likewise a low HHI can indicate a lower likelihood of coordinated interactions among suppliers and could be used to support a claim of a lack of market power by a seller that is pivotal or does have a 20 percent or greater market share in some or all season/load conditions. For example, a seller with a market share of 20 percent or greater could argue that … it would be unlikely to possess market power in an unconcentrated market (HHI less than 1000).[18]

In a market with an inelastic demand curve, the existence of two jointly pivotal suppliers, regardless of the amount of excess capacity available, does not provide a market structure that will result in a competitive outcome. The 20 percent market share and the HHI screen are also weak screens for structural market power on a stand-alone basis. A market share in excess of 20 percent does not demonstrate market power if the holder of that market share is not jointly pivotal and is unlikely to be able to affect the market price. A market share less than 20 percent does not demonstrate the absence of market power if the holder of that market share is jointly pivotal and is likely to be able to affect the market price. An HHI in excess of 2500 does not demonstrate market power if the relevant owners are not jointly pivotal and are unlikely to be able to affect the market price. An HHI less than 2500 does not demonstrate the absence of market power if the relevant owners are jointly pivotal and are likely to be able to affect the market price.[19]

The three pivotal supplier test is a reasonable application of the Commission's delivered price test to the case of load pockets that arise in a market based on security-constrained, economic dispatch with locational market pricing and extremely inelastic demand. The three pivotal supplier test also exists in the context of a local market power mitigation rule that relies on a structure test, a participant behavior test and a market impact test. The three pivotal supplier test explicitly incorporates the relationship between supply and demand in the definition of pivotal, and it provides a clear test for whether excess supply is adequate to offset other structural features of the market and results in an adequately competitive market structure. The greater the supply relative to demand, the less likely that three suppliers will be jointly pivotal, all else equal.

The three pivotal supplier test represents a significant modification of the previously existing PJM local market power rule, which did not include an explicit market structure test. The goal of applying a market structure test is to continue to limit the exercise of market power by generation owners in load pockets but to lift offer capping when the market structure makes the exercise of market power less likely. The goal of the three pivotal supplier test, proposed by PJM, was not to weaken

17 *See* Order No. 697 at PP 111–117; AEP Order at PP 111–12.
18 Order No. 697 at P 111.
19 For detailed examples, see Joseph E. Bowring, PJM market monitor. "MMU Analysis of Combined Regulation Market," PJM Market Implementation Committee Meeting (December 20, 2006).

the local market power rules but to make them more flexible by adding an explicit market structure test. As recognized by PJM when the local market power rule was proposed in 1997 and has continued to be the case, the local markets created by transmission constraints are generally not structurally competitive. Nonetheless, it is appropriate to have a clear test as to when a local market is adequately competitive to permit the relaxation of local market power mitigation. The three pivotal supplier test proposed by PJM is not a guarantee that suppliers will behave in a competitive manner in load pockets. The three pivotal supplier test is a structural test that is not a perfect predictor of actual behavior. The existence of this risk is the reason that the PJM Tariff language also includes the ability of the MMU to request that the Commission reinstate offer caps in cases where there is not a competitive outcome.

Three Pivotal Supplier Test: Mechanics

The three pivotal supplier test measures the degree to which the supply from three generation suppliers is required in order to meet the demand to relieve a constraint. Two key variables in the analysis are the demand and the supply. The demand consists of the incremental, effective MW required to relieve the constraint. The supply consists of the incremental, effective MW of supply available to relieve the constraint at a distribution factor (DFAX) greater than, or equal to, the DFAX used by PJM in operations.[20] For purposes of the test, incremental effective MW are attributed to specific suppliers on the basis of their control of the assets in question. Generation capacity controlled directly or indirectly through affiliates or through contracts with third parties are attributed to a single supplier.

The supply directly included as relevant to the market in the three pivotal supplier test consists of the incremental, effective MW of supply that are available at a price less than, or equal to, 1.5 times the clearing price (P_c) that would result from the intersection of demand (constraint relief required) and the incremental supply available to resolve the constraint. This measure of supply is termed the relevant effective supply (S) in the market for the relief of the constraint in question. In every case, incrementally available supply is measured as incremental effective MW of supply, as shown in Equation L-1, and the clearing price (P_c) is defined as shown in Equation L-2:

Equation L-1 Incremental effective MW of supply

$MW \bullet DFAX$; and

Equation L-2 Price of clearing offer

$$P_c = \frac{Offer_c - SMP}{DFAX_c} .$$

To be part of the relevant market, the effective offer of incremental supplier i must be less than, or equal to, 1.5 times P_c:

20 A unit's contribution toward effective, incrementally available supply is based on the DFAX of the unit relative to the constraint and the unit's incrementally available capacity over current load levels, to the extent that the capacity in question can be made available within an hour of the time the relief will be needed. Effective, incrementally available MW from an unloaded 100 MW 15-minute start combustion turbine (CT) with a DFAX of 0.05 to a constraint would be 5 MW relative to the constraint in question. Effective, incrementally available MW from a 200 MW steam unit, with 100 MW loaded, a 50 MW ramp rate and a DFAX of 0.5 to the constraint would be 25 MW.

Equation L-3 Relevant and effective offer

$$P_{ie} = \frac{Offer_i - SMP}{DFAX_i} \leq 1.5 \bullet P_c .$$

Where the effective incremental supply of supplier *i* is a function of price:

Equation L-4 Relevant and effective supply of supplier i

$$S_i = MW\left(P_{ie}\right) \bullet DFAX_i .$$

Where S_i is the relevant, incremental and effective supply of supplier *i*, total relevant, incremental and effective supply for suppliers *i*=1 to n is shown in Equation L-5:

Equation L-5 Total relevant, effective supply

$$S = \sum_{i=1}^{n} S_i .$$

Each effective supplier, from 1 to n, is ranked, from the largest to the smallest relevant effective supply, relative to the constraint for which it is being tested. In the first iteration of the test, the two largest suppliers are combined with the third largest supplier, and this combined supply is subtracted from total relevant effective supply. The resulting net amount of relevant effective supply is divided by the total relief required (*D*). Where *j* defines the supplier being tested in combination with the two largest suppliers (initially the third largest supplier with *j*=3), Equation L-6 shows the formula for the three pivotal supplier metric, i.e., the residual supply index for three pivotal suppliers (RSI3):

Equation L-6 Calculating the three pivotal supplier test

$$RSI3_j = \frac{\sum_{i=1}^{n} S_i - \sum_{i=1}^{2} S_i - S_j}{D} .$$

Where *j*=3, if $RSI3_j$ is less than, or equal to, 1.0, then the three largest suppliers in the market for the relief of the constraint fail the three pivotal supplier test. That is, the three largest suppliers are jointly pivotal for the local market created by the need to relieve the constraint using local, out-of-merit units. If $RSI3_j$ is greater than 1.0, then the three largest potential suppliers of relief MW pass the test and the remaining suppliers (*j*=4..n) pass the test. In the event of a failure of the three largest suppliers, further iterations of the test are needed, with each subsequent iteration testing a subsequently smaller supplier (*j*=4..n) in combination with the two largest suppliers. In each iteration, if $RSI3_j$ is less than 1.0, it indicates that the tested supplier, in combination with the two largest suppliers, has failed the test. Iterations of the test continue until the combination of the two largest suppliers and a supplier *j* result in $RSI3_j$ greater than 1.0. When the result of this process is that $RSI3_j$ is greater than 1.0, the remaining suppliers pass the test.

If a supplier fails the test for a constraint, units that are part of a supplier's relevant effective supply with respect to a constraint can have their offers capped at cost plus 10 percent, or cost plus relevant adders for frequently mitigated units and associated units. Offer capping only occurs to the extent that the units of this supplier's relevant, effective supply are offered at greater than cost plus 10 percent and are actually dispatched to contribute to the relief of the constraint in question.

Defining the market

The goal of defining the relevant market is to include those producers that actually compete to determine the market price or could actually compete to determine the market price. Conversely, the goal of defining the relevant market is to exclude those units that are not meaningful competitors and therefore do not have an impact on the clearing price. The existence of market power within that defined market depends on the ability of the firm to raise price while continuing to sell its output. A firm cannot successfully increase the market price above the competitive level if competitors would replace its output when it did so.

The Commission definition of the relevant market includes all suppliers which have costs less than or equal to 1.05 times the clearing price. The Commission definition means that, if the marginal unit sets the clearing price based on an offer of $200 per MWh, all units with costs less than, or equal to, $210 per MWh have a competitive effect on the offer of the marginal unit. These units are all defined to be meaningful competitors in the sense that it is assumed that their behavior constrains the behavior of the marginal and inframarginal units. The three pivotal supplier definition means that, if the marginal unit sets the clearing price based on an offer of $200 per MWh, all units with costs less than, or equal to, $300 per MWh have a competitive effect on the offer of the marginal unit. These units are all defined to be meaningful competitors in the sense that it is assumed that their behavior constrains the behavior of the marginal and inframarginal units. Clearly, the three pivotal supplier test incorporates a definition of meaningful competitors that is at the extremely high end of inclusive. It is certainly questionable whether a unit with a competitive offer price of $300 offer meaningfully constrains the offer of a $200 unit. This very broad market definition is combined with the recognition that multiple owners can be jointly pivotal. The three pivotal supplier test includes three pivotal suppliers while the Commission test includes only one pivotal supplier.

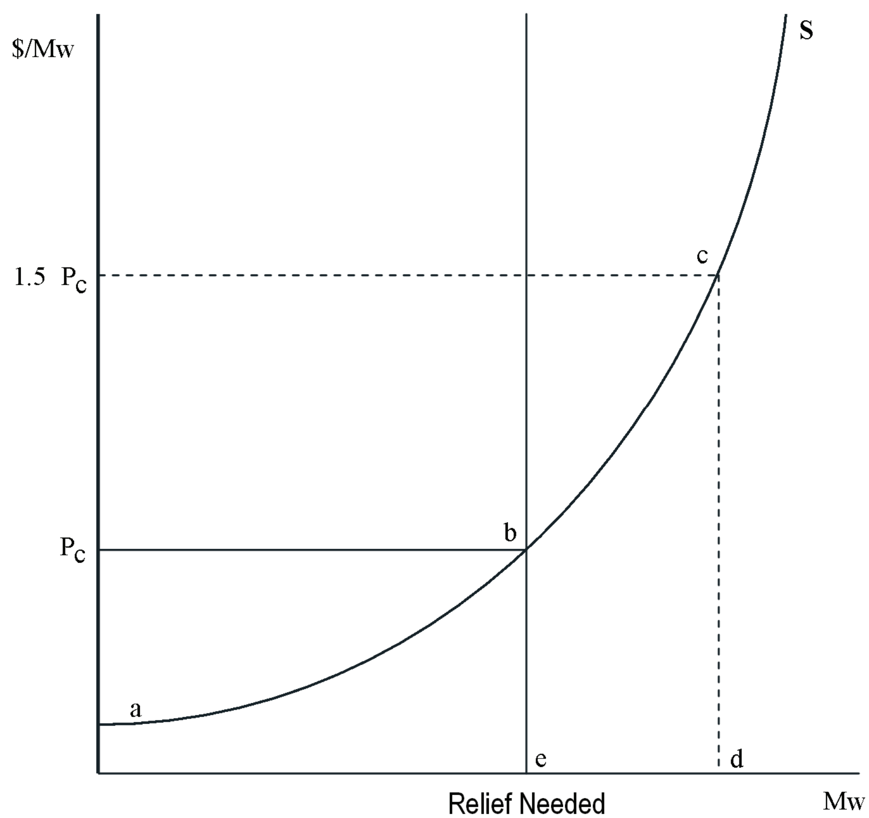
The three pivotal supplier test is designed to test the relevant market. For example, in the case of the market for out of merit generation needed to relieve a constraint in real time, the three pivotal supplier test examines the market specifically available to provide that relief. Under these conditions, the three pivotal supplier test measures the degree to which the supply from three generation suppliers, as defined by PJM's market solution software, is required in order to meet the demand to relieve a constraint. The market demand consists of the incremental, effective MW required to relieve the constraint. The market supply consists of the incremental, effective MW of supply available to relieve the constraint.[21] For purposes of the test, incremental effective MW are attributed to specific suppliers on the basis of their control of the assets in question. Generation capacity controlled directly or indirectly through affiliates or through contracts with third parties are attributed to a single supplier.

21 A unit's contribution toward effective, incrementally available supply is based on the DFAX of the unit relative to the constraint and the unit's incrementally available capacity over current load levels, if the capacity in question is available within an hour of the time the relief will be needed. Effective, incrementally available MW from an unloaded 100 MW 15-minute start combustion turbine (CT) with a DFAX of 0.05 to a constraint would be 5 MW relative to the constraint in question. Effective, incrementally available MW from a 200 MW steam unit, with 100 MW loaded, a 50 MW ramp rate and a DFAX of 0.5 to the constraint would be 25 MW.

The supply directly included as relevant to the market in the three pivotal supplier test consists of the incremental, effective MW of supply that are available at a price less than, or equal to, 1.5 times the clearing price (P_c) that would result from the intersection of demand (constraint relief required) and the incremental supply available to resolve the constraint. This measure of supply is termed the relevant effective supply (S) in the market for the relief of the constraint in question. In every case, incrementally available supply is measured as incremental effective MW of supply, as shown in Equation L-1, and the clearing price (P_c) is defined as shown in Equation L-1 above.

Figure L-1 illustrates the interaction between the relief requirement and the effective supply available, as recognized by PJM's solution software. The clearing price (P_c) is generated at the point of intersection of the relief required (D) and relevant effective supply (S). The effective cost and MW pairs from a particular participant are based on the lesser of the participant's cost or price schedule, if the unit is offline, or the current operational (price or cost) schedule if the unit is already being dispatched by PJM. The relief requirement can be fully met at the point of intersection (b) of (D) and (S) by the effective MW available at P_c (e). However, as indicated above, the market defined for the test also includes potentially effective MW in excess of what is needed to clear the market (d), defined as the effective MW available at a price less than, or equal to, 1.5 times the clearing price (P_c).

Figure L-1 Definition of relevant market



Unlike structural tests that define markets by geographic proximity, TPS makes explicit and direct use of the incremental, effective MW of supply available to relieve the constraint at a distribution factor (DFAX) greater than, or equal to, the DFAX used by PJM in operations. Only the supply that is part of the market as defined by the reality of the electric network as measured by unit characteristics and distribution factors is included in the three pivotal supplier test, to the extent that it is incremental, effective MW of supply that is available at a price less than, or equal to, 1.5 times the clearing price (P_c) that would result from the intersection of demand (constraint relief required) and the incremental supply available to resolve the constraint.

APPENDIX M – STANDARD MARKET METRICS

Monitoring Analytics uses a number of measures of the market structure, participant behavior and market performance. These metrics include, but are not limited to market share, residual supply index, Herfindahl-Hirschman Index, markup and net revenue.

Market Share

Market share is calculated based on participant specific volumes cleared in each iteration of the relevant market. For example, in the day-ahead energy market, the market clears every hour. Market shares are calculated in each hour based on each participant's cleared volumes in that hour.

A participant's market share is only calculated for those iterations of the market in which the participant cleared volume. For example, if Participant A delivered power only in hours 14 and 15 of a given day, Participant A's market share would be calculated only for hours 14 and 15. When calculating average market share for the day, Participant A's average market share would take the average of the market iterations within the day where Participant A cleared market volumes: hours 14 and 15. When calculating average market share for the year, Participant A's average market share would take the average of the market iterations within the year where Participant A cleared market volumes: hours 14 and 15. This ensures that participant specific market shares are examined within their relevant market space.

Herfindahl-Hirschman Index (HHI)

Concentration ratios are a summary measure of market share, a key element of market structure. High concentration ratios indicate that comparatively small numbers of sellers dominate a market; low concentration ratios mean larger numbers of sellers split market sales more equally. The best tests of market competitiveness are direct tests of the conduct of individual participants and their impact on price. The price-cost markup index is one such test and direct examination of offer behavior by individual market participants is another. Low aggregate market concentration ratios establish neither that a market is competitive nor that participants are unable to exercise market power. High concentration ratios do, however, indicate an increased potential for participants to exercise market power.

Despite their significant limitations, concentration ratios provide useful information on market structure. 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.

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.[1]

1 77 FERC ¶ 61,263, "Inquiry Concerning the Commission's Merger Policy under the Federal Power Act: Policy Statement," Order No. 592, pp. 64-70.

Residual Supply Index (RSI)

PJM utilizes the Three Pivotal Supplier (TPS) Test in the Regulation Market, the Capacity Market and the Energy Market to detect structural market power. The residual supply index is the metric used to determine the outcome of the TPS. Each supplier, from 1 to n, is ranked from the largest to the smallest offered MW of eligible regulation supply in each hour. Suppliers are then tested in order, starting with the three largest suppliers. In each iteration of the test, the two largest suppliers are combined with a third supplier, and the combined supply is subtracted from total effective supply. The resulting net amount of eligible supply is divided by the demand for the hour (*D*).

Where *j* defines the supplier being tested in combination with the two largest suppliers (initially the third largest supplier with *j*=3), Equation M-1 shows the formula for the residual supply index for three pivotal suppliers (RSI3):

Equation M-1 Calculating the three pivotal supplier test

$$RSI3_j = \frac{\sum_{i=1}^{n} S_i - \sum_{i=1}^{2} S_i - S_j}{D}$$

Where *j*=3, if $RSI3_j$ is less than or equal to 1.0, then the three suppliers are jointly pivotal and the suppliers being tested fail the three pivotal supplier test. Iterations of the test continue until the combination of the two largest suppliers and a supplier *j* result in $RSI3_j$ greater than 1.0. When the result of this process is that $RSI3_j$ is greater than 1.0, the remaining suppliers pass the test.

Markup

The price-cost markup index is a measure of conduct or behavior by the owners of generating units and not a measure of market impact. For marginal units, the markup index is a measure of market power. For units not on the margin, the markup index is a measure of the intent to exercise market power or, in cases where the markup results in higher-priced units replacing lower-priced units in the dispatch, also a measure of market power. A positive markup by marginal units results in a difference between the observed market price and the competitive market price. The goal of the markup analysis is both to calculate the actual markups by marginal units (market conduct) and to estimate the impact of those markups on the difference between the observed market price and the competitive market price (market impact or market performance). The results must be interpreted carefully, however, because the impact is not based on a full redispatch of the system. The markup index for each marginal unit is normalized and can vary from -1.00 when the offer price is less than marginal cost, to 1.00 when the offer price is higher than marginal cost. In the energy market, 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. This index calculation method weights the impact of individual unit markups using sensitivity factors.[2]

2 Sensitivity factors define the impact of each marginal unit on LMP at every bus on the system. See the *2008 State of the Market Report*, Volume II, Appendix K, "Calculation and Use of Generator Sensitivity/Unit Participation Factors."

Net Revenue

Net revenue is an indicator of generation investment profitability and thus is a measure of overall market performance as well as a measure of the incentive to invest in new generation to serve PJM markets. Net revenue quantifies the contribution to capital cost received by generators from all PJM markets. Although it can be expected that in the long run, in a competitive market, net revenue from all sources will cover the fixed costs of investing in new generating resources, including a competitive return on investment, actual results are expected to vary from year to year. Wholesale energy markets, like other markets, are cyclical. When the markets are long, prices will be lower and when the markets are short, prices will be higher. Zonal net revenue reflects differences in locational energy prices and differences in locational capacity prices. The zonal variation in net revenue illustrates the substantial impact of location on economic incentives.

APPENDIX N – GLOSSARY

Aggregate	Combination of buses or bus prices.
Ancillary Services	Those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Provider's Transmission System in accordance with Good Utility Practice..
Area Control Error (ACE)	Area Control Error of the PJM RTO is the actual net interchange minus the biased scheduling net interchange, including time error. It is the sum of tie-in errors and frequency errors.
Associated unit (AU)	A unit that is located at the same site as a frequently mitigated unit (FMU) and which has identical electrical and economic impacts on the transmission system as an FMU but which does not qualify for FMU status.
Auction Revenue Right (ARR)	A financial instrument entitling its holder to auction revenue from Financial Transmission Rights (FTRs) based on locational marginal price (LMP) differences across a specific path in the Annual FTR Auction.
Automatic Generation Control (AGC)	An automatic control system comprised of hardware and software. Hardware is installed on generators allowing their output to be automatically adjusted and monitored by an external signal and software is installed facilitating that output adjustment.
Average hourly LMP	An LMP calculated by averaging hourly LMP with equal hourly weights; also referred to as a simple average hourly LMP.
Avoidable cost rate (ACR)	The costs that a generation owner would not incur if the generating unit did not operate for one year, in particular the delivery year. The ACR calculation is based on the categories of cost that are specified in Section 6.8 of Attachment DD of the PJM Tariff.
Avoidable Project Investment Recovery Rate (APIR)	A component of the avoidable cost rate (ACR) calculation. Project investment is the capital reasonably required to enable a capacity resource to continue operating or improve availability during peak-hour periods during the delivery year.

Balancing energy market	Energy that is generated and financially settled during real time.
Base Residual Auction (BRA)	Reliability Pricing Model (RPM) auction held in May three years prior to the start of the delivery year. Allows for the procurement of resource commitments to satisfy the region's unforced capacity obligation and allocates the cost of those commitments among the LSEs through the Locational Reliability Charge.
Bilateral agreement	An agreement between two parties for the sale and delivery of a service.
Black Start Unit	A generating unit with the ability to go from a shutdown condition to an operating condition and start delivering power without any outside assistance from the transmission system or interconnection.
Bottled generation	Economic generation that cannot be dispatched because of local operating constraints.
Burner tip fuel price	The cost of fuel delivered to the generator site equaling the fuel commodity price plus all transportation costs.
Bus	An interconnection point.
Capacity deficiency rate (CDR)	The CDR was designed to reflect the annual fixed costs of a new combustion turbine (CT) in PJM and the annual fixed costs of the associated transmission investment, including a return on investment, depreciation and fixed operation and maintenance expense, net of associated energy revenues. The CDR is used in applying penalties for capacity deficiencies. To express the CDR in terms of unforced capacity, it must be further divided by the quantity 1 minus the EFORd.
Capacity Emergency Transfer Limit (CETL)	The capability of the transmission system to support deliveries of electric energy to a given area experiencing a localized capacity emergency as determined in accordance with the PJM Manuals.
Capacity queue	A collection of Regional Transmission Expansion Planning (RTEP) capacity resource project requests received during a particular timeframe and designating an expected in-service date.

Combined Cycle (CC)	An electric generating technology in which electricity and process steam are produced from otherwise lost waste heat exiting from one or more combustion turbines. The exiting heat is routed to a conventional boiler or to a heat recovery steam generator for use by a conventional steam turbine in the production of electricity. This process increases the efficiency of the electric generating facility.
Combustion Turbine (CT)	A generating unit in which a combustion turbine engine is the prime mover for an electrical generator.
Congestion Management Process (CMP)	A process used between neighboring balancing authorities to coordinate the re-dispatch of resources to relieve transmission constraints.
Control Zone	An area within the PJM Control Area, as set forth in the PJM Open Access Transmission Tariff and the RAA. Schedule 16 of the RAA defines the distinct zones that comprise the PJM Control Area.
Decrement Bids (DEC)	An hourly bid, expressed in MWh, to purchase energy in the PJM Day-Ahead Energy Market if the Day-Ahead LMP is less than or equal to the specified bid price. This bid must specify hourly quantity, bid price and location (transmission zone, hub, aggregate or single bus).
Demand deviations	Hourly deviations in the demand category, equal to the difference between the sum of cleared decrement bids, day-ahead load, day-ahead sales, and day-ahead-exports, to the sum of real-time load, real-time sales, and real-time exports.
Demand Resource	A capacity resource with a demonstrated capability to provide a reduction in demand or otherwise control load. A Demand Resource may be an existing or planned resource.
Dispatch Rate	The control signal, expressed in dollars per MWh, calculated and transmitted continuously and dynamically to direct the output level of all generation resources dispatched by PJM in accordance with the Offer Data.
Disturbance Control Standard	A NERC-defined metric measuring the ability of a control area to return area control error (ACE) either to zero or to its predisturbance level after a disturbance such as a generator or transmission loss.

Eastern Prevailing Time (EPT)	Eastern Prevailing Time (EPT) is equivalent to Eastern Standard Time (EST) or Eastern Daylight Time (EDT) as is in effect from time to time.
Eastern Region	Defined region for purposes of allocating balancing operating reserve charges. Includes the BGE, DOM, PENELEC, PEPCO, METED, PPL, JCPL, PECO, DPL, PSEG, and RECO transmission zones.
Economic generation	Units producing energy at an offer price less than or equal to LMP.
End-use customer	Any customer purchasing electricity at retail.
Equivalent availability factor (EAF)	The proportion of hours in a year that a unit is available to generate at full capacity.
Equivalent demand forced outage rate (EFORd)	A measure of the probability that a generating unit will not be available due to forced outages or forced deratings when there is a demand on the unit to generate.
Equivalent forced outage factor (EFOF)	The proportion of hours in a year that a unit is unavailable because of forced outages.
Equivalent maintenance outage factor (EMOF)	The proportion of hours in a year that a unit is unavailable because of maintenance outages.
Equivalent planned outage factor (EPOF)	The proportion of hours in a year that a unit is unavailable because of planned outages.
External resource	A generation resource located outside metered boundaries of the PJM RTO.
Financial Transmission Right (FTR)	A financial instrument entitling the holder to receive revenues based on transmission congestion measured as hourly energy LMP differences in the PJM Day-Ahead Energy Market across a specific path.
Firm Point-to-Point Transmission Service	Transmission Service that is reserved and/or scheduled between specified Points of Receipt and Delivery.
Firm Transmission Service	Transmission service that is intended to be available at all times to the maximum extent practicable, subject to an emergency, and unanticipated failure of a facility, or other event beyond the control of the owner or operator of the facility, or the Office of the Interconnection.

Fixed Demand Bid	Bid to purchase a defined MW level of energy, regardless of LMP.
Fixed Resource Requirement (FRR)	An alternative method for a Party to satisfy its obligation to provide Unforced Capacity. Allows an LSE to avoid direct participation in the RPM Auctions by meeting their fixed capacity resource requirement using internally owned capacity resources
Frequently mitigated unit (FMU)	A unit that was offer-capped for more than a defined proportion of its real-time run hours in the most recent 12-month period. FMU thresholds are 60 percent, 70 percent and 80 percent of run hours. Such units are permitted a defined adder to their cost-based offers in place of the usual 10 percent adder.
Generation Control Area (GCA) and Control Area (LCA)	Designations used on a NERC Tag to describe the Load balancing authority where the energy is generated (GCA) and the balancing authority where the load is served (LCA). Note: the terms “Control Area” in these acronyms are legacy terms for balancing authority, and are expected to be changed in the future.
Generator deviations	Hourly deviations in the generator category, equal to the difference between a unit’s cleared day-ahead generation, and a unit’s hourly, integrated real-time generation.
Generation Offers	Schedules of MW offered and the corresponding offer price.
Generation owner	A PJM member that owns or leases, with rights equivalent to ownership, facilities for generation of electric energy that are located within PJM.
Gross export volume (energy)	The sum of all export transaction volume (MWh).
Gross import volume (energy)	The sum of all import transaction volume (MWh).
Gigawatt (GW)	A unit of power equal to 1,000 megawatts.
Gigawatt-day	One GW of energy flow or capacity for one day.
Gigawatt-hour (GWh)	One GWh is a gigawatt produced or consumed for one hour.
Herfindahl-Hirschman Index (HHI)	HHI is calculated as the sum of the squares of the market share percentages of all firms in a market.

Hertz (Hz)	Electricity system frequency is measured in hertz.
HRSG	Heat recovery steam generator. An air-to-steam heat exchanger.
Increment offers (INC)	Financial offers in the Day-Ahead Energy Market to supply specified amounts of MW at, or above, a given price.
Incremental Auction	Reliability Pricing Model (RPM) auction to allow for an incremental procurement of resource commitments to satisfy an increase in the region's unforced capacity obligation due to a load forecast increase or a decrease in the amount of resource commitments due to a resource cancellation, delay, derating, EFORd increase, or decrease in the nominated value of a Planned Demand Resource.
Inframarginal unit	A unit that is operating, with an accepted offer that is less than the clearing price.
Installed capacity	Installed capacity is the as-tested maximum net dependable capability of the generator, measured in MW.
Load	Demand for electricity at a given time.
Load Management	Previously known as ALM (Active Load Management). ALM was a term that PJM used prior to the implementation of RPM where end use customer load could be reduced at the request of PJM. The ability to reduce metered load, either manually by the customer, after a request from the resource provider which holds the Load management rights or its agent (for Contractually Interruptible), or automatically in response to a communication signal from the resource provider which holds the Load management rights or its agent (for Direct Load Control).
Load-serving entity (LSE)	Load-serving entities provide electricity to retail customers. Load-serving entities include traditional distribution utilities and new entrants into the competitive power market.
Locational Deliverability Area (LDA)	Sub-regions used to evaluate locational constraints. LDAs include EDC zones, sub-zones, and combination of zones.

Lost opportunity cost (LOC)	The difference in net compensation from the Energy Market between what a unit receives when providing regulation or synchronized reserve and what it would have received for providing energy output.
Marginal unit	The last generation unit to supply power under a merit order dispatch system.
Market-clearing price	The price that is paid by all load and paid to all suppliers.
Market participant	A PJM market participant can be a market supplier, a market buyer or both. Market buyers and market sellers are members that have met creditworthiness standards as established by the PJM Office of the Interconnection.
Market user interface	A thin client application allowing generation sellers to provide and to view generation data, including bids, unit status and market results.
Maximum daily starts	The maximum amount of times a unit can start in a day. An operating parameter on unit's schedule.
Maximum weekly starts	The maximum amount of times a unit can start in a week. An operating parameter on unit's schedule.MeanT h e arithmetic average.
Median	The midpoint of data values. Half the values are above and half below the median.
Megawatt (MW)	A unit of power equal to 1,000 kilowatts.
Megawatt-day	One MW of energy flow or capacity for one day.
Megawatt-hour (MWh)	One MWh is a megawatt produced or consumed for one hour.
Megawatt-year	One MW of energy flow or capacity for one calendar year.
Minimum down time	The minimum amount of time that a unit has to stay down for before turning on again. An operating parameter on unit's schedule.
Minimum run time	The minimum amount of time that a unit has to stay on before shutting down. An operating parameter on unit's schedule.

Monthly CCM	The capacity credits cleared each month through the PJM Monthly Capacity Credit Market (CCM).
Multimonthly CCM	The capacity credits cleared through PJM Multimonthly Capacity Credit Market (CCM).
Net excess (capacity)	The net of gross excess and gross deficiency, therefore the total PJM capacity resources in excess of the sum of load-serving entities' obligations.
Net exchange (capacity)	Capacity imports less exports.
Net interchange (energy)	Gross import volume less gross export volume in MWh.
Network Transmission Service	Transmission service that is for the sole purpose of serving network load. Network transmission service is only available to network customers.
Noneconomic generation	Units producing energy at an offer price greater than the LMP.
Non-Firm Transmission Service	Point-to-point transmission service under the PJM tariff that is reserved and scheduled on an as available basis and is subject to curtailment or interruption. Non-firm point to point transmission service is available on a stand-alone basis for periods ranging from one hour to one month.
North American Electric Reliability Council (NERC)	A voluntary organization of U.S. and Canadian utilities and power pools established to assure coordinated operation of the interconnected transmission systems.
Off peak	For the PJM Energy Market, off-peak periods are all NERC holidays (i.e., New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, Christmas Day) and weekend hours plus weekdays from the hour ending at midnight until the hour ending at 0700.
On peak	For the PJM Energy Market, on-peak periods are weekdays, except NERC holidays (i.e., New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, Christmas Day) from the hour ending at 0800 until the hour ending at 2300.

Parameter-limited schedule	A schedule for a unit that has parameters that are used when the unit fails the three pivotal supplier test, or in a maximum generation emergency event. These parameters are pre-determined by the MMU based on unit class, unless an exception is otherwise granted.
PJM member	Any entity that has completed an application and satisfies the requirements of the PJM Board of Managers to conduct business with PJM, including transmission owners, generating entities, load-serving entities and marketers.
PJM planning year	The calendar period from June 1 through May 31.
Point of Receipt (POR) and Point of Delivery (POD)	Designations used on a transmission reservation. The designations, when combined, determine the transmission reservations' market path.
Pool-scheduled resource	A generating resource that the seller has turned over to PJM for scheduling and control. Price duration curve A graphic representation of the percent of hours that a system's price was at or below a given level during the year.
Price-sensitive bid	Purchases of a defined MW level of energy only up to a specified LMP. Above that LMP, the load bid is zero.
Primary operating interfaces	Primary operating interfaces are typically defined by a cross section of transmission paths or single facilities which affect a wide geographic area. These interfaces are modeled as constraints whose operating limits are respected in performing dispatch operations.
Ramp-limited desired (MW)	The achievable MW based on the UDS requested ramp rate.
Regional Transmission Expansion (RTEP) Protocol	The process by which PJM recommends specific Planning transmission facility enhancements and expansions based on reliability and economic criteria.

ReliabilityFirst Corporation	ReliabilityFirst Corporation (RFC) began operation January 1, 2006, as the successor to three other reliability organizations: the Mid-Atlantic Area Council (MAAC), the East Central Area Coordination Agreement (ECAR), and the Mid-American Interconnected Network (MAIN). PJM is registered with RFC to comply with its reliability standards for balancing authority (BA), planning coordinator (PC), reliability coordinator (RC), resource planner (RP), transmission operator (TOP), transmission planner (TP) and transmission service provider (TSP).
Reliability Pricing Model (RPM)	PJM's resource adequacy construct. The purpose of RPM is to develop a long term pricing signal for capacity resources and LSE obligations that is consistent with the PJM Regional Transmission Expansion Planning Process (RTEPP). RPM adds stability and a locational nature to the pricing signal for capacity.
Selective catalytic reduction (SCR)	NOx reduction equipment usually installed on combined-cycle generators.
Self-scheduled generation	Units scheduled to run by their owners regardless of system dispatch signal. Self-scheduled units do not follow system dispatch signal and are not eligible to set LMP. Units can be submitted as a fixed block of MW that must be run, or as a minimum amount of MW that must run plus a dispatchable component above the minimum.
Shadow price	The constraint shadow price represents the incremental reduction in congestion cost achieved by relieving a constraint by 1 MW. The shadow price multiplied by the flow (in MW) on the constrained facility during each hour equals the hourly gross congestion cost for the constraint.
Sources and sinks	Sources are the origins or the injection end of a transmission transaction. Sinks are the destinations or the withdrawal end of a transaction.
Spot Import Transmission Service	Transmission service introduced as an option for non-load serving entities to offer into the PJM spot market at the border/interface as price takers.
Spot market	Transactions made in the Real-Time and Day-Ahead Energy Market at hourly LMP.

Static Var compensator	A static Var compensator (SVC) is an electrical device for providing fast-acting, reactive power compensation on high-voltage electricity transmission networks.
Supply deviations	Hourly deviations in the supply category, equal to the difference between the sum of cleared increment offers, day-ahead purchases, and day-ahead imports, to the sum of real-time purchases and real-time imports.
Synchronized reserve	Reserve capability which is required in order to enable an area to restore its tie lines to the pre-contingency state within 10 minutes of a contingency that causes an imbalance between load and generation. During normal operation, these reserves must be provided by increasing energy output on electrically synchronized equipment, by reducing load on pumped storage hydroelectric facilities or by reducing the demand by demand-side resources. During system restoration, customer load may be classified as synchronized reserve.
System installed capacity	System total installed capacity measures the sum of the installed capacity (in installed, not unforced, terms) from all internal and qualified external resources designated as PJM capacity resources.
System lambda	The cost to the PJM system of generating the next unit of output.
Temperature-humidity index (THI)	A temperature-humidity index (THI) gives a single, numerical value reflecting the outdoor atmospheric conditions of temperature and humidity as a measure of comfort (or discomfort) during warm weather. THI is defined as: $THI = T_d – (0.55 – 0.55RH) * (T_d - 58)$ where T_d is the dry-bulb temperature and RH is the percentage of relative humidity.
Transmission Adequacy and Reliability Assessment (TARA)	An analysis tool that can calculate generation to load impacts. This tool is used to facilitate loop flow analysis across the Eastern Interconnection.
Turn down ratio	The ratio of dispatchable megawatts on a unit’s schedule. Calculated by a unit’s economic maximum MW divided by its economic minimum MW. An operating parameter of a unit’s schedule.
Unforced capacity	Installed capacity adjusted by forced outage rates.

Western region	Defined region for purposes of allocating balancing operating reserve charges. Includes the AEP, APS, COMED, DUQ, and DAYTON transmission zones.
Wheel-through	An energy transaction flowing through a transmission grid whose origination and destination are outside of the transmission grid.
Zone	See "Control zone" (above).

APPENDIX O – LIST OF ACRONYMS

ACE	Area control error
ACR	Avoidable cost rate
AECI	Associated Electric Cooperative Inc.
AECO	Atlantic City Electric Company
AEG	Alliant Energy Corporation
AEP	American Electric Power Company, Inc.
AGC	Automatic generation control
ALM	Active load management
ALTE	Eastern Alliant Energy Corporation
ALTW	Western Alliant Energy Corporation
AMIL	Ameren - Illinois
AMRN	Ameren
AP	Allegheny Power Company
APIR	Avoidable Project Investment Recovery
ARR	Auction Revenue Right
ARS	Automatic reserve sharing
ATC	Available transfer capability
AU	Associated unit

BAAL	Balancing authority ACE limit
BGE	Baltimore Gas and Electric Company
BGS	Basic generation service
BME	Balancing market evaluation
BRA	Base Residual Auction
Btu	British thermal unit
C&I	Commercial and industrial customers
CAIR	Clean Air Interstate Rule
CAISO	California Independent System Operator
CBL	Customer base line
CC	Combined cycle
CCM	Capacity Credit Market
CDR	Capacity deficiency rate
CDTF	Cost Development Task Force
CETL	Capacity emergency transfer limit
CETO	Capacity emergency transfer objective
CF	Coordinated flowgate under the Joint Operating Agreement between PJM and the Midwest Independent Transmission System Operator, Inc.
CILC	Central Illinois Light Company Interface
CILCO	Central Illinois Light Company

CIN	Cinergy Corporation
CLMP	Congestion component of LMP
CMP	Congestion management process
ComEd	The Commonwealth Edison Company
Con Edison	The Consolidated Edison Company
CONE	Cost of new entry
CP	Pulverized coal-fired generator
CPL	Carolina Power & Light Company
CPS	Control performance standard
CSP	Curtailment service provider
CT	Combustion turbine
CTR	Capacity transfer right
DASR	Day-Ahead Scheduling Reserve
DAY	The Dayton Power & Light Company
DC	Direct current
DCS	Disturbance control standard
DEC	Decrement bid
DFAX	Distribution factor
DL	Diesel

DLCO	Duquesne Light Company
DPL	Delmarva Power & Light Company
DPLN	Delmarva Peninsula north
DPLS	Delmarva Peninsula south
DR	Demand response
DSR	Demand-side response
DUK	Duke Energy Corp.
EAF	Equivalent availability factor
ECAR	East Central Area Reliability Council
EDC	Electricity distribution company
EDT	Eastern Daylight Time
EEA	Emergency energy alert
EES	Enhanced Energy Scheduler
EFOF	Equivalent forced outage factor
EFORd	Equivalent demand forced outage rate
EHV	Extra-high-voltage
EKPC	East Kentucky Power Cooperative, Inc.
EMAAC	Eastern Mid-Atlantic Area Council
EMOF	Equivalent maintenance outage factor

EMS	Energy management system
EPOF	Equivalent planned outage factor
EPT	Eastern Prevailing Time
EST	Eastern Standard Time
ExGen	Exelon Generation Company, L.L.C.
FE	FirstEnergy Corp.
FERC	The United States Federal Energy Regulatory Commission
FMU	Frequently mitigated unit
FPA	Federal Power Act
FPR	Forecast pool requirement
FRR	Fixed resource requirement
FTR	Financial Transmission Right
GCA	Generation control area
GE	General Electric Company
GW	Gigawatt
GWh	Gigawatt-hour
HHI	Herfindahl-Hirschman Index
HRSG	Heat recovery steam generator
HVDC	High-voltage direct current

Hz	Hertz
IA	RPM Incremental Auction
ICAP	Installed capacity
IDC	Interchange distribution calculator
IESO	Ontario Independent Electricity System Operator
ILR	Interruptible load for reliability
INC	Increment offer
IP	Illinois Power Company
IPL	Indianapolis Power & Light Company
IPP	Independent power producer
IRM	Installed reserve margin
IRR	Internal rate of return
ISA	Interconnection service agreement
ISO	Independent system operator
JCPL	Jersey Central Power & Light Company
JOA	Joint operating agreement
JOU	Jointly owned units
JRCA	Joint Reliability Coordination Agreement
LAS	PJM Load Analysis Subcommittee

LCA	Load control area
LDA	Locational deliverability area
LGEE	LG&E Energy, L.L.C.
LM	Load management
LMP	Locational marginal price
LOC	Lost opportunity cost
LSE	Load-serving entity
MAAC	Mid-Atlantic Area Council
MAAC+APS	Mid-Atlantic Area Council plus the Allegheny Power System
MACRS	Modified accelerated cost recovery schedule
MAIN	Mid-America Interconnected Network, Inc.
MAPP	Mid-Continent Area Power Pool
MCP	Market-clearing price
MDS	Maximum daily starts
MDT	Minimum down time
MEC	MidAmerican Energy Company
MECS	Michigan Electric Coordinated System
Met-Ed	Metropolitan Edison Company
MICHFE	The pricing point for the Michigan Electric Coordinated System and FirstEnergy control areas

MIL	Mandatory interruptible load
MIS	Market information system
MISO	Midwest Independent Transmission System Operator, Inc.
MMU	PJM Market Monitoring Unit
Mon Power	Monongahela Power
MP	Market participant
MRC	Markets and reliability committee
MRT	Minimum run time
MUI	Market user interface
MW	Megawatt
MWh	Megawatt-hour
MWS	Maximum weekly starts
NAESB	North American Energy Standards Board
NCMPA	North Carolina Municipal Power Agency
NEPT	Neptune DC line
NERC	North American Electric Reliability Council
NICA	Northern Illinois Control Area
NIPSCO	Northern Indiana Public Service Company
NNL	Network and native load

NO_x	Nitrogen oxides
NUG	Non-utility generator
NYISO	New York Independent System Operator
OA	Amended and Restated Operating Agreement of PJM Interconnection, L.L.C.
OASIS	Open Access Same-Time Information System
OATI	Open Access Technology International, Inc.
OATT	PJM Open Access Transmission Tariff
ODEC	Old Dominion Electric Cooperative
OEM	Original equipment manufacturer
OI	PJM Office of the Interconnection
Ontario IESO	Ontario Independent Electricity System Operator
OVEC	Ohio Valley Electric Corporation
PAR	Phase angle regulator
PE	PECO zone
PEC	Progress Energy Carolinas, Inc.
PECO	PECO Energy Company
PENELEC	Pennsylvania Electric Company
Pepco	Formerly Potomac Electric Power Company or PEPCO
PJM	PJM Interconnection, L.L.C.

PJM/AEPNI	The interface between the American Electric Power Control Zone and Northern Illinois
PJM/AEPPJM	The interface between the American Electric Power Control Zone and PJM
PJM/AEPVP	The single interface pricing point formed in March 2003 from the combination of two previous interface pricing points: PJM/American Electric Power Company, Inc. and PJM/Dominion Resources, Inc.
PJM/AEPVPEXP	The export direction of the PJM/AEPVP interface pricing point
PJM/AEPVPIMP	The import direction of the PJM/AEPVP interface pricing point
PJM/ALTE	The interface between PJM and the eastern portion of the Alliant Energy Corporation's control area
PJM/ALTW	The interface between PJM and the western portion of the Alliant Energy Corporation's control area
PJM/AMRN	The interface between PJM and the Ameren Corporation's control area
PJM/CILC	The interface between PJM and the Central Illinois Light Company's control area
PJM/CIN	The interface between PJM and the Cinergy Corporation's control area
PJM/CPLE	The interface between PJM and the eastern portion of the Carolina Power & Light Company's control area
PJM/CPLW	The interface between PJM and the western portion of the Carolina Power & Light Company's control area
PJM/CWPL	The interface between PJM and the City Water, Light & Power's (City of Springfield, IL) control area

PJM/DLCO	The interface between PJM and the Duquesne Light Company's control area
PJM/DUK	The interface between PJM and the Duke Energy Corp.'s control area
PJM/EKPC	The interface between PJM and the Eastern Kentucky Power Corporation's control area
PJM/FE	The interface between PJM and the FirstEnergy Corp.'s control area
PJMICC	PJM Industrial Customer Coalition
PJM/IP	The interface between PJM and the Illinois Power Company's control area
PJM/IPL	The interface between PJM and the Indianapolis Power & Light Company's control area
PJM/LGEE	The interface between PJM and the Louisville Gas and Electric Company's control area
PJM/MEC	The interface between PJM and MidAmerican Energy Company's control area
PJM/MECS	The interface between PJM and the Michigan Electric Coordinated System's control area
PJM/MISO	The interface between PJM and the Midwest Independent System Operator
PJM/NEPT	The interface between PJM and the New York Independent System Operator over the Neptune DC line
PJM/NIPS	The interface between PJM and the Northern Indiana Public Service Company's control area
PJM/NYIS	The interface between PJM and the New York Independent System Operator

PJM/Ontario IESO	PJM/Ontario IESO pricing point
PJM/OVEC	The interface between PJM and the Ohio Valley Electric Corporation’s control area
PJM/TVA	The interface between PJM and the Tennessee Valley Authority’s control area
PJM/VAP	The interface between PJM and the Dominion Virginia Power’s control area
PJM/WEC	The interface between PJM and the Wisconsin Energy Corporation’s control area
PLS	Parameter limited schedule
PMMS	Preliminary market structure screen
PNNE	PENELEC’s northeastern subarea
PNNW	PENELEC’s northwestern subarea
POD	Point of delivery
POR	Point of receipt
PPL	PPL Electric Utilities Corporation
PSE&G	Public Service Electric and Gas Company (a wholly owned subsidiary of PSEG)
PSEG	Public Service Enterprise Group
PSN	PSEG north
PSNC	PSEG northcentral
RAA	Reliability Assurance Agreement among Load-Serving Entities

RCIS	Reliability Coordinator Information System
RECO	Rockland Electric Company zone
RFC	ReliabilityFirst Corporation
RLD (MW)	Ramp-limited desired (Megawatts)
RLR	Retail load responsibility
RMCP	Regulation market-clearing price
RPM	Reliability Pricing Model
RSI	Residual supply index
RSI_x	Residual supply index, using “x” pivotal suppliers
RTC	Real-time commitment
RTEP	Regional Transmission Expansion Plan
RTO	Regional transmission organization
SCE&G	South Carolina Energy and Gas
SCPA	Southcentral Pennsylvania subarea
SCR	Selective catalytic reduction
SEPA	Southeast Power Administration
SEPJM	Southeastern PJM subarea
SERC	Southeastern Electric Reliability Council
SFT	Simultaneous feasibility test

SMECO	Southern Maryland Electric Cooperative
SMP	System marginal price
SNJ	Southern New Jersey
SO_2	Sulfur dioxide
SOUTHEXP	South Export pricing point
SOUTHIMP	South Import pricing point
SPP	Southwest Power Pool, Inc.
SPREGO	Synchronized reserve and regulation optimizer (market-clearing software)
SRMCP	Synchronized reserve market-clearing price
STD	Standard deviation
SVC	Static Var compensator
SWMAAC	Southwestern Mid-Atlantic Area Council
TARA	Transmission adequacy and reliability assessment
TDR	Turn down ratio
TEAC	Transmission Expansion Advisory Committee
THI	Temperature-humidity index
TLR	Transmission loading relief
TPS	Three pivotal supplier
TPSTF	Three Pivotal Supplier Task Force

TVA	Tennessee Valley Authority
UCAP	Unforced capacity
UDS	Unit dispatch system
UGI	UGI Utilities, Inc.
UPF	Unit participation factor
VACAR	Virginia and Carolinas Area
VAP	Dominion Virginia Power
VOM	Variable operation and maintenance expense
VRR	Variable resource requirement
WEC	Wisconsin Energy Corporation
WLR	Wholesale load responsibility
WPC	Willing to pay congestion