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BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Commission's Investigation into the Value of Continued Participation of Ohio's Electric Utilities in Regional Transmission Organizations	)))))	Case No. 09-90-EL-COI

COMMENTS OF PJM INTERCONNECTION, L.L.C. IN RESPONSE TO THE COMMISSION'S INVESTIGATION INTO THE VALUE OF CONTINUED PARTICIPATION OF OHIO'S ELECTRIC UTILITIES IN REGIONAL TRANSMISSION ORGANIZATIONS

PJM Interconnection L.L.C. (PJM) welcomes the opportunity to provide the Public Utilities Commission of Ohio (PUCO or Commission) with its perspective on the value of continued participation of Ohio's electric utilities in RTOs, and to address many of the questions set forth by the Commission regarding the value of Regional Transmission Organizations to Ohio consumers. The Federal Energy Regulatory Commission (FERC) has recognized PJM as an independent entity equipped to manage transmission facilities placed under its functional control in accordance with an Open Access Transmission Tariff (OATT or Tariff); and as a Regional Transmission Organization (RTO) that meets FERC's criteria for a regional entity with greater ability to ensure the fairness of transmission access.[1] PJM currently 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) pursuant to its OATT accepted by the FERC. PJM is the transmission provider under, and the administrator of, the PJM OATT, administers the Regional Transmission Expansion Planning Process (RTEPP), and controls the day-to-day operations of the bulk power system of the whole PJM Region.

[1] *See Pennsylvania-New Jersey-Maryland Interconnection,* 81 FERC ¶ 61,252 (1997), *reh'g denied,*, 92 FERC ¶ 61,282 (2000); *PJM Interconnection, L.L.C.,* 101 FERC ¶ 61,345 (2002); *PJM Interconnection, L.L.C.,* 81 FERC ¶ 61,257 (1997), and *PJM Interconnection L.L.C.,* 96 FERC ¶ 61,061 (2001), order on compliance filing, 98 FERC ¶ 61,072 (2002).

In accepting PJM's OATT, FERC has acknowledged among other things the reliability and economic benefits of centralized security-constrained economic dispatch, and market-based congestion management using Locational Marginal Pricing (LMP) and Financial Transmission Rights (FTRs). FERC has established the scope and oversees the activities of PJM's Independent Market Monitor (IMM),[2] and has also deemed PJM's IMM to be an effective means of monitoring the PJM Markets and conducting retrospective mitigation, subject to Attachment M (PJM Market Monitoring Plan) to the PJM OATT.[3] Responsibilities of PJM's IMM include the duty to monitor matters related to transmission congestion pricing, exercise of market power, structural problems in the PJM Market, design flaws in the operating rules, and compliance with the standards, procedures, or practices as set forth in the PJM OATT, Operating Agreement, Reliability Agreement, and the PJM Manuals, and the IMM is authorized by FERC to report its findings directly to that agency (*see response to Question 5 for additional information on the duties of the IMM).*

PJM acknowledges that stakeholders and the Commission itself may take issue with FERC's decisions , and supports their right to advocate and participate actively before FERC, as well as ultimately to challenge FERC's decisions through the federal appellate process. Nevertheless, PJM is under the jurisdiction of FERC. The FERC's authority and jurisdiction over PJM is granted by Federal Power Act (FPA) section 205 and 206, 16 U.S.C. 824d and 824e. The FPA establishes FERC's jurisdiction over wholesale and interstate transmission of electricity.[4] FERC reaffirmed it legal authority over RTOs in Order No. 2000.[5] Therefore, the PUCO should give deference to the findings of FERC, as the agency with exclusive jurisdiction over PJM as an RTO on issues under consideration in this proceeding.

[2] *PJM Interconnection, L.L.C.*, Order Approving Market Monitoring Plan as Modified, 86 FERC ¶ 61,247 (1999).

[3] *See Allegheny Electric Cooperative, Inc., et al. v. PJM Interconnection, L.L.C.*, Docket Nos. EL07-56-000 and EL-07-58, 122 FERC ¶ 61,257 (2008). *See also Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, 73 Fed. Reg. 64,100 (2008), FERC Stats. & Regs. ¶ 31,281 (2008) (Order No. 719).

[4] *See New York v. FERC*, 535 U.S. 1 (2002) (the Court upheld FERC's assertions regarding the extent of its jurisdiction over transmission in Order No. 888).

[5] Order No. 2000, *Regional Transmission Organizations*, [Regs. Preambles 1996-2000] F.E.R.C. STATS. & REGS. ¶ 31,069, at p. 30,995 (2000), 65 Fed. Reg. 809 (2000) (codified at 18 C.F.R. pt. 35) (Order No. 2000), *order on reh'g*. Order No. 2000-A, F.E.R.C. STATS. & REGS. ¶ 31,092, 65 Fed. Reg 12,088 (2000) (Order No. 2000-A), *aff'd sub nom, Pub. Util. Dist. No. 1 v. FERC*, 272 F.3d 607 (D.C. Cir. 2001).

Overview of PJM

PJM's mission is set forth in its FERC-approved Amended and Restated Operating Agreement of PJM Interconnection, L.L.C.(Operating Agreement).[6] It is: to 1) promote the safe and reliable operation of the bulk power facilities in the PJM region; 2) create and operate a robust, competitive and non-discriminatory electric power market in the PJM region; and 3) avoid undue influence over the operation of the bulk power facilities by any market participant or group of market participants. PJM's competitive wholesale power market, the world's largest, provides PJM's system operators with a more effective means of managing congestion on the electric system, and thereby maintaining system reliability, than is the case absent a wholesale market. At the same time, PJM's wholesale market provides transparent pricing information that market participants can use to manage their energy market transactions more effectively.

PJM is responsible for assuring both the short-term and the long-term reliability of the transmission system. PJM ensures short-term reliability by 1) receiving, confirming and implementing all interchange schedules; 2) ordering the re-dispatch of generators connected to PJM-controlled transmission facilities; 3) approving all scheduled outages of transmission facilities; 4) scheduling generator maintenance outages; 5) monitoring the electrical system on a real-time basis; and 6) implementing emergency procedures required to maintain system reliability. PJM's world-class system-management tools enable it to run a "security analysis" every minute, processing 68,000 data points every ten seconds and evaluating almost 4000 contingencies. PJM maintains long-term reliability by assuring that the nation's reliability standards are met through its long-term planning process.

PJM covers an area encompassing all or parts of 13 states, including portions of Ohio, and the District of Columbia. Because all of the transactions involving PJM are wholesale transactions and are necessarily part of interstate commerce, the PJM market does not encompass retail transactions or the retail market that fall under the jurisdiction of the Public Utilities Commission of Ohio. PJM is responsible for keeping the regional electric system running - for "keeping the lights on" - and its wholesale market is designed with that end in mind. PJM operations ensure that generation resources are deployed in the appropriate locations through the operation of the wholesale electricity market. The PJM wholesale market pricing system, LMP, ensures that PJM is able to operate the bulk power system consistent with regional grid reliability standards and the principles of least-cost, economic dispatch. Utilities that are participants in the

[6] Rate Schedule FERC No. 24.

PJM wholesale market serve over 51 million people and the market area encompasses all or part of the states of Delaware, Indiana, Illinois, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. As an RTO, PJM does not own transmission or generation facilities, generate electricity, or buy energy for resale. PJM has no retail customers and does not operate long-term forward bilateral markets. PJM, as an independent system operator, coordinates the operation of transmission and generation facilities within its footprint so that all market participants have equal access to the benefits of the regional grid operation. PJM also coordinates its operations with interconnected transmission operators, including the Midwest ISO at its border in Ohio and elsewhere.

PJM ensures that energy deliveries are scheduled reliably and are coordinated inter-regionally. Since electricity cannot be stored, electricity supply and demand must be balanced on a second-by-second basis; PJM performs this region-wide balancing of load and generation in real time while ensuring that all regional transmission reliability constraints are managed appropriately. This real-time generation dispatch function is critical to make sure that the transmission system can handle the requested energy deliveries which are scheduled to maximize the value of economic power transfers for the benefit of all customers in the region.

PJM administers a set of rules and market clearing procedures that govern how participants can buy and sell energy and related services in the wholesale market. PJM's goal is to be sure, to the extent possible within reliability constraints, that at any moment in time the least expensive set of generating resources is operating to serve the regional electricity demand. The wholesale market pricing system, LMP, ensures that the price of energy at a given location is consistent with the dispatch instructions issued by the RTO to maintain operational grid reliability. This consistency between wholesale prices and reliability instructions allows the wholesale spot market prices to provide the correct incentives for all market participants to do what the RTO needs them to do to keep the lights on.

The regional scope of the wholesale market provides benefits to consumers by providing access to less expensive power resources through coordinated regional grid operations. In a broader regional market, customers have access to a larger number of resources because of the market's size and because barriers to trade are eliminated. Market participants also benefit from the large-scale regional market because it is competitive. As an independent system operator, PJM is free from undue influence by market participants. The IMM ensures that market outcomes are competitive and PJM's markets are free from the undue exercise of market power.

Preliminary Observations on the PUCO's Inquiry: the Question of "Value"

PJM believes that it provides valuable services to consumers in the PJM footprint, and that these services are provided at reasonable cost. PJM has provided answers to the questions posed in the Commission's Entry demonstrating the value of PJM's services.

PUCO initiated Case No. 09-90-EL-COI, *In the Matter of the Commission's Investigation Into the Value of Continued Participation in Regional Transmission Organizations*, pursuant to Section 4928.24, Ohio Revised Code, to develop a record for PUCO's Federal Advocate to inform a report for the Commission on whether continued participation of the State of Ohio's electric utilities in Regional Transmission Organizations is in the interest of retail electric service customers. The Entry initiating the proceeding acknowledges that several issues complicate such an investigation. It acknowledges complications in determining the impact RTOs have had on electricity prices because of difficulty in isolating the impacts of other factors, such as the cost of fuels used to generate electricity, changes in the fuel mix, and changes in consumer demand. The Entry also acknowledges the difficulties in evaluating what may have occurred had RTOs not been established, and concedes that "some analysis may be more qualitative as opposed to quantitative." Other complications noted by the Entry are that Ohio's electric utilities operate under different retail regulatory conditions, and Ohio is served by two RTOs.

The Commission's Entry neglects to address several other complications that render aspects of the Inquiry problematic. Foremost of these is that the principal benefits of RTO participation to Ohio consumers are the *regional* reliability and economies of scale that RTOs provide.[7] Because of the interconnected nature of the transmission grid and the fact that "reliability" and "scale economies" in that context are regional phenomena, their value is not realistically or meaningfully allocable to states or other geographical subdivisions that comprise the RTO footprint. Corollary to that consideration, the benefits attributable to RTO participation are in large part a function of state and national electricity policy frameworks that are dynamic. It is ironic that Ohio Senate Bill 221, the legislation prompting the Commission's inquiry, not only

[7] Since August 2003, when Ohio was the epicenter of a major electrical system disturbance that crippled much of the Northeast, affecting 40 million Americans at an economic cost of $6 billion, RTOs have institutionalized systems and procedures that address significant failures of diagnostic support identified by the Power System Outage Task Force as responsible for the Blackout, including the required utilization of real-time data for flowgate monitoring and joint procedures for coordination of a security limit violation.

required that the Commission and its Federal Advocate undertake this inquiry; it also established electricity resource requirements to meet Ohio consumer electricity demands that will accentuate the value of RTOs in delivering renewable resources to Ohio electricity consumers. When one considers the potential regional and national impacts of increased reliance on renewable resources, mandates for increased energy efficiency, or the potential for carbon emissions reduction, it becomes clear that an evaluation of the benefits associated with regional reliability and regional economies-of-scale must take into account the potential impact of the implementation of national energy policy currently under consideration in Congress, as well as of the implementation of Senate Bill 221 itself.

To come to terms with these complications, PJM is responding to the Commission's inquiries by providing both quantitative and qualitative information clarifying how PJM provides regional reliability and economies of scale, and refrains from allocating a proportion of their benefits to Ohio.[8] PJM has developed a "value proposition" – a quantitative analysis of the regional benefits associated with the array of reliability services and scale economies it provides – and offers the Commission the results of and the basis for that analysis below, situated in response to the first two questions posed by the Commission's Entry. PJM also provides answers to most of the Commission's other questions posed in its Entry, consistent with an emphasis that Ohio consumers benefit from PJM's regional reliability services and the economies of scale it provides. Where appropriate, PJM's responses to the Commission's questions address the important role RTOs will continue to play as Ohio's energy policies and federal energy policies are implemented.

The Commission's Entry infers that one standard for assessing RTO "value" is the impact of RTO presence on retail prices. Assessment of the "value" of RTOs is often premised on the observation that retail prices in deregulated states have increased in conjunction with wholesale markets. But comparisons of rates in regulated and deregulated states often neglect to consider that to begin with, deregulation was more likely to be implemented in states facing higher regulated rates than in states which did not restructure their retail electricity markets. Often intended to buttress a preconceived notion, such comparisons do not attempt to isolate and control for underlying economic factors affecting retail electricity prices such as retail market structure, historical fuel mix, and the establishment of retail access. As a result, such comparisons mask the beneficial effects attributable to the implementation of coordinated wholesale markets by PJM and other RTOs. PJM submits that it is possible to disentangle the impacts of underlying economic factors from the

[8] Ohio's share of PJM load is approximately nine percent, but for the reasons set forth it is inadvisable to attribute nine percent of PJM's reliability and economies of scale to Ohio's "benefit".

effects attributable to the implementation of coordinated wholesale markets. A study commissioned by PJM in 2006[9] found that the implementation of coordinated markets in PJM and NYISO produced retail rate reductions saving customers between $430 million and $1.3 billion annually, compared to the charges consumers would have faced under a traditional regulatory regime. The study overcame the conceptual difficulties inherent in evaluating the economic impact of coordinated markets on consumers – the difficulties acknowledged by the Commission in its Entry establishing this proceeding – by controlling for the impact on average retail rates of differences in retail access programs across utilities and regions; and finding an appropriate way to take into account the impact of differences in regional generation fuel mix, in particular gas dependence, on changes over time in average retail rates.

There are other ways to conceptualize "value" that are very germane to the Commission's Inquiry, *i.e.* where value intersects with legislative purpose. The wholesale electricity market platform underpins and facilitates retail electric service. As such, it is instrumental for the realization of the legislated energy policy of the State, encoded at Ohio Revised Code Section 4928.02. Among the values embodied in the General Assembly's energy policy statement are reliable service, retail choice, and transparency of information. RTOs are institutions that facilitate those values; so in a consideration of the "value" of RTOs to Ohio consumers, a legitimate approach to evaluate their worth is to consider their utility for manifesting the values embedded in the law, or even whether the policy could be effectuated in their absence. PJM submits that RTOs enable retail competition, provide the foundation for reliability at the retail level, and provide transparent information about the transmission system. Furthermore, the portfolio standard requirements enacted by the Ohio General Assembly in Senate Bill 221 call for increased dependence on renewable resources, access to which is provided by the regional bulk power system.[10] Senate Bill 221 also establishes that electric utilities or electric service companies may use renewable energy credits to satisfy renewable resource benchmark requirements; PJM Environmental Information Services Inc. is the

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[9] *Analysis of the Impact of Coordinated Electricity Markets on Consumer Electricity Charges,* Scott M. Harvey, Bruce M. McConihe and Susan L. Pope, LECG LLC, November 20, 2006.

[10] Ohio is one of ten states in the PJM footprint that have renewable portfolio standard initiatives in place, posing a challenge for resource development and access that PJM is well positioned to address through its regional transmission planning process. See Table 9.5 in *PJM 2008 Regional Transmission Expansion Plan,* February 27, 2009, p. 311 for a summary of the RPS initiative of states within PJM's footprint.

developer of the Generation Attributes Tracking System to create, track and facilitate trading of renewable energy credits.[11]

Institutions like PJM can also provide "value" not subject to quantification by developing and providing decision-makers with unique information that, by virtue of the data RTOs have at hand, can inform policy analysis. This is particularly true during periods between the establishment and maturation of regulatory and market paradigms and the bodies of policy that underpin them. A timely example is provided by PJM's recent analysis of the degree to which imposition of carbon cap-and trade levies on current system production costs would need to increase to effectuate changes in carbon emissions.[12] And there are many other emerging initiatives in which PJM is engaged and undoubtedly providing "value" not subject to quantification. Policy-related examples include PJM's partnering with stakeholders and decision-makers to assist in the facilitation and deployment of advanced technologies including synchro-phasors and electric plug-in vehicles,[13] PJM's formation of a Smart Grid Working Group in 2008 to develop an approach for PJM Transmission Owners to provide recommendations for the implementation of technologies in PJM, and PJM's recent launch of The Renewable Energy Dashboard on its website that provides consumers with a better understanding of renewable power in the PJM region.[14] Other value-enhancing initiatives reflect PJM's commitment to improving its business platform, e.g. through the upcoming implementation on June 1st of weekly market settlements that mitigates the credit exposure of PJM's members.

[11]See *Comments of PJM Environmental Information Services, Inc.*, Requirements, and Amendments of Chapter 4901:5-1, 4901:5-3, and 4901:5-7 of the Ohio Administrative Code pursuant to Chapter 4928, Revised Code, to Implement Senate Bill No. 221.

[12] See *Potential Effects of Proposed Climate Change Policies on PJM's Energy Market*, Dr. Paul Sotkiewicz, PJM Interconnection LLC, January 28, 2009. The study used market models to simulate the impact of climate change legislation in 2013. It concludes among other things that leading legislative proposals of the 110th Congress to reduce carbon dioxide emissions from fossil-fuel generation plants could increase wholesale electricity prices from between $7.50 per MWh to $45.00 per MWh in 2013, and that a carbon dioxide price of about $40/ton would be necessary for natural gas combined cycle generating units to run in place of coal generating units on a large scale.

[13] PJM is one of the founding members of The Ohio State University's SMART@CAR Initiative, and is also collaborating with the Mid-Atlantic Grid-Interactive Car (MAGIC) Consortium on the demonstration of how the grid can facilitate plug-and-play technology.

[14] The Renewable Energy Dashboard is accessible at green.pjm.com and displays information gathered in large part from the Generation Attribute Tracking System developed by PJM affiliate PJM-EIS.

PJM's Responses to the Commission's Questions

1. Are FERC's Order 2000 goals and objectives being realized to promote efficiency in wholesale electric markets and to ensure that consumers pay the lowest possible price for reliable service?

While Order No. 888[15] set the foundation upon which competitive electric markets could develop, the FERC found in Order No. 2000 that it did not eliminate the potential to engage in undue discrimination and preference in the provision of transmission service.[16] FERC recognized that Order No. 888 did not address the regional nature of the grid, including the treatment of parallel flows, pancaked rates, and congestion management. In Order No. 2000, FERC also recognized that there continue to be important transmission-related impediments to a competitive wholesale electric market. These impediments include the engineering and economic inefficiencies inherent in the current operation and expansion of the transmission grid and the continuing opportunities for transmission owners to unduly discriminate in the operation of their transmission systems to favor their own or their affiliates' power marketing activities.

The engineering and economic inefficiencies FERC identified and sought to address in Order No. 2000 resulted from the lack of regional coordination of an interconnected transmission grid. FERC concluded that a properly structured RTO could provide significant benefits in the operation of the transmission grid. A successful RTO would, through transmission grid management, improve grid reliability, remove remaining opportunities for discriminatory transmission practices, improve market performance, and facilitate lighter handed regulation. These efficiencies would include, among other things, regional transmission pricing, improved congestion management of the grid, more accurate total transmission capability (TTC) and available transmission capability (ATC) calculations, more effective management of parallel path flows, reduced transaction costs, and facilitation of state retail access programs. Thus, the FERC encouraged the creation of RTOs to address important operational and reliability issues and eliminate any residual discrimination in transmission services that can occur when the operation of the transmission system remains in the control of a vertically integrated utility. The FERC found that RTOs would increase the

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[15] Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, 61 FR 21540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 (1996), order on reh'g, Order No. 888-A, 62 FR 12274 (Mar. 14, 1997), FERC Stats. & Regs. ¶ 31,048 (1997), order on reh'g, Order No. 888-B, 81 FERC ¶ 61,248 (1997), order on reh'g, Order No. 888-C, 82 FERC ¶ 61,046 (1998), aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC, 225 F.3d 667 (D.C. Cir. 2000) (TAPS v. FERC), aff'd sub nom. New York v. FERC, 535 U.S. 1 (2002).

[16] Order No. 2000 at 31,015.

efficiency of wholesale markets by eliminating pancaked rates, internalizing parallel flow, managing congestion efficiently, and operating markets for energy, capacity and ancillary services.

FERC recently reaffirmed these findings in Order No. 890.[17] In Order No. 890, the FERC took additional regulatory steps because large areas of the Nation did not develop RTOs using the voluntary structure adopted by the FERC in Order No. 2000.[18] The reforms adopted by the FERC were designed to: (1) strengthen the pro forma OATT to ensure that it achieves its original purpose of remedying undue discrimination; (2) provide greater specificity to reduce opportunities for undue discrimination and facilitate the FERC's enforcement; and (3) increase transparency in the rules applicable to planning and use of the transmission system. The FERC in Order No. 890, however, did not find that the objectives addressed by RTOs under Order No. 2000 were not being realized. In fact, to the contrary, the FERC found that some of the changes adopted in Order No. 890 were not relevant to RTOs. "For example, many RTOs use bid – based locational markets and financial rights to address transmission congestion, rather than the first-come, first-service physical rights model set forth in the *pro forma* OATT. ...(N)othing in this rulemaking is intended to upset the market design used by existing ISOs and RTOs."[19]

Therefore, it is clear that FERC continues to believe that Order No. 2000's goals and objectives are being realized to promote efficiency in wholesale electric markets and to ensure that consumers pay the lowest possible price for reliable service in competitive markets administered by RTOs. The PUCO should take judicial notice of the FERC's findings in this proceeding in reaching the same conclusion.

In addition to FERC's findings noted above, PJM also offers the following information taken from a 2005 report by the ISO/RTO Council on "The Value of Independent Regional Grid Operators" filed in FERC Docket No. AD05-13-000, which is still pertinent today:

"ISO/RTOs conduct various activities that improve accessibility for market participants, including improving the coordination and compatibility of billing and settlements for trading within and between regions; *increasing the consistency of bidding protocols across regions, including* creating single-point regional

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[17] Preventing Undue Discrimination and Preference in Transmission Service, Order No. 890, III FERC Stats. & Regs., Regs. Preambles ¶ 31,241 (2007).

[18] *See* Order No. 890 at p. 21.

[19] Order No. 890 at p. 158.

transaction entry; allowing cross-border congestion hedges; and moving toward wide-area locational marginal pricing (LMP) dispatch that can increase the efficiency of inter-ISO/RTO energy trading."

"Within organized markets, every market participant can see pricing information and thereby avoid using the least efficient plants. ISO/RTOs use security-constrained unit commitment software to dispatch the units with the lowest bids consistent with transmission availability and grid reliability requirements. The result creates prices that every market participant can see and benefit from, and avoids using the least efficient plants unless they are needed for dispatch adequacy or reliability. In contrast, dispatch outside organized markets may not always use the most efficient generators, but the lack of market prices and transparency about which plants are operating and at what cost, means that customers and regulators cannot see the excess costs.

FERC observes that:

Locational marginal, day-ahead and real time process, along with capacity and ancillary services within ISO/RTO markets, are almost entirely transparent and make much information available in real time. Such transparency rests on standardized operations and large, centralized mechanisms to collect and disseminate the information. By contrast, most... bilateral electric markets provide far less detailed information. Some electric power markets are almost entirely opaque to both regulators and to price-takers. In these markets (such as electricity in much of the southeast), so little information is available that price indices either do not develop or have little value in price discovery.[20]

FERC also notes that:

Customers in regions without organized markets had significantly less market information about prices, price formation, system conditions and transmission infrastructure needs than their counterparts in regions with organized markets. Outside organized markets there was limited market price information regarding the value of electricity over time and across locations of the regional needs of transmission and generation siting, resulting in:

- Opaque (non-transparent) prices;
- Less-efficient dispatch of power plants;

[20] FERC 2004 State of the Market Report, p. 36.

- Use of less-efficient congestion management tools; and
- Muted or distorted signals for investment, particularly where it is most needed.

The poor quality of information outside organized markets limited the effective functioning of wholesale markets in those areas, potentially resulting in higher costs to customers.[21]

ISO/RTOs enhance reliability by informing all market participants on the state of grid conditions and market operations through the public posting of electricity prices and other key system information on their websites. Market prices in ISO/RTO markets reflect real-time system conditions. Higher prices signal to loads that generation supply has tightened, enabling loads and off-line generators to respond in a timely manner. In the markets where LMP is used, high LMPs give very specific signals as to where more generation or power delivery is needed and valued, while lower LMPs indicate the reverse....

...Although grid flows are managed to assure that every customer receives sufficient electricity, ISO/RTOs track and account for the transactions that are blocked due to grid congestion, and tabulate the increased costs of the transactions that occur in their stead.

ISO/RTO regions that run competitive wholesale markets using locational marginal pricing or zonal pricing use those pricing signals to manage congestion. Load-serving entities can manage congestion costs using financial hedging instruments (usually called financial transmission rights or FTRs), which are generally distributed to historical users of the grid (primarily those serving loads) and sometimes through auction. Once issued, FTRs can be traded in ... auctions administered by the ISO/RTO, or traded bilaterally with other market participants....

...Organized markets offer the most options for risk management and risk reduction. These include a mix of long-term, day-ahead and real-time markets to structure an electricity portfolio with predictable electricity prices."[22]

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[21] FERC 2003 State of the Market Report at pp. 8-9.

[22] *The Value of Independent Regional Grid Operators*, a report by the ISO/RTO Counsel, November 2005, FERC Docket No. AD05-13-000.

2. Are RTOs providing value to Ohio's customers through more effective management and use of the grid by:

(a) Addressing discrimination in access to transmission service?

(b) Elimination of pancaked transmission rates?

(c) Regional transmission scheduling, tariff administration, and settlements?

(d) Enhancing reliability?

(e) Improved utilization of transmission assets and management of transmission congestion?

(f) Regional unit commitment and security constrained economic dispatch?

(g) Regional procurement of Ancillary Services and consolidation of Balancing Authorities?

(h) Regional transmission planning?

The answer to each of the above questions is yes. Pursuant to Order No. 2000, FERC requires all RTOs it authorizes to provide the services listed above by demonstrating the following four core characteristics and eight key functions:[23]

Minimum Characteristics: (1) Independence, (2) Scope and Regional Configuration, (3) Operational Authority, and (4) Short-term Reliability.

Minimum Functions: (1) Tariff Administration and Design, (2) Congestion Management, (3) Parallel Path Flow, (4) Ancillary Services, (5) OASIS and Total Transmission Capability (TTC) and Available Transmission Capability (ATC), (6) Market Monitoring, (7) Planning and Expansion, and (9) Interregional Coordination.

By Order issued on December 20, 2002, FERC granted PJM full RTO status.[24] In the PJM RTO Order, the Commission found that PJM meets all of the minimum characteristics and functions required by Order No. 2000 but required a compliance filing that explained more fully how PJM's planning process will identify expansions that are needed to support competition (*i.e.* economic/congestion based upgrades). Subsequent filings modifying PJM's RTEPP including compliance filings required by Order No. 890 resulted

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[23] *See* Order No. 2000-A at p. 2.

[24] *PJM Interconnection, L.L.C., et.al.,* 101 FERC ¶ 61,345 (2002) (the "PJM RTO Order").

in FERC's orders approving PJM's current planning and expansion process in the RTEPP which meets or exceeds the requirements of both Order No. 2000 and Order No. 890. Therefore, the Commission in this proceeding should give deference to FERC's findings granting PJM full RTO status and subsequent findings in proceedings addressing issues regarding PJM's Markets, market monitoring, regional planning, reliability, tariff administration and settlements, etc. Many of these topics are discussed more fully below.

One of the most valuable benefits of ISO/RTO formation for electricity buyers has been to eliminate "pancaked rates," substituting a single rate for the wheel through an ISO/RTO region. "By combining a number of transmission systems into a large, unified service area, ISO/RTOs reduce the fees paid by wholesale customers for wheeling energy through the area. Before RTO formation, an energy buyer who wanted to import electricity from a distant generator would have to pay a fee to every transmission owner on the path between the producer and the delivery point on the grid.... At the same time, the process of requesting and receiving transmission service over a long distance has been made much easier for the buyer. The process once required multiple requests for every transmission provider, with potentially different or incompatible timing and availability. With ISO/RTOs in place, the buyer makes a single request for transmission service anywhere within or across the ISO/RTO region and gets a single response that assures reliable transmission service for the transaction. Additionally, generation within that footprint receives network transmission service across the region – which, as in PJM or the Midwest ISO, reaches millions of retail electric customers in many states."[25]

Furthermore, in Docket Nos. ER05-6, *et al.* relating to the implementation of the Seams Elimination Charge/Cost Adjustment/Assignment ("SECA") FERC eliminated pancaked transmission rates or regional through-and-out rates in the combined region of PJM and the Midwest Independent Transmission System Operator Corporation.

The following information published recently in PJM's 2008 Annual Report is also pertinent:

"With PJM's scope and scale, the efficiencies we deliver in such areas as reliability, generation investment, production costs and grid services are significant. In fact, we estimate that those benefits to the region are as much as $2.3 billion a year." (re:6)

[25] *The Value of Independent Regional Grid Operators*, a report by the ISO/RTO Counsel, November 2005, FERC Docket No. AD05-13-000.

"The region's infrastructure development received much-needed impetus from the state approvals of the Trans-Allegheny Interstate Line (502 Junction-Loudoun), a project required under our .. (RTEP), and the success of the May Reliability Pricing Model (RPM) capacity auction, which produced 4,200 megawatts of new capacity and demand-side resources." (re: 6)

"In 2008, PJM and its members delivered about 759 million megawatt-hours of electricity. For the second consecutive year, no new summer peak-demand record was set. The highest load for the year was reached on June 9, at 130,300 megawatts (MW). The all-time peak remains 144,644 MW, set in August 2006." (re: 12)

"Nonetheless, PJM system operators encountered challenging conditions early in June, when extreme winds caused transmission line outages in Maryland and Virginia and tornadoes caused outages in Illinois and Michigan. In the wake of the storms, PJM worked with the transmission owners to coordinate high-priority repairs to transmission lines that enabled the grid to meet consumers' demand of 130,000 MW of electricity while temperatures reached the 90s." (re: 12)

"Reinforcing PJM's ability to effectively and securely manage the grid is the Advanced Control Center (AC^2) program. The construction portion of the program for the second data and operations control center is complete, with physical security having been given a top priority. In 2008, generation and power dispatching and reliability engineering functions were initiated at the new facility while development work continues on the software architecture and new energy-management and market-management systems that are part of the program." (re: 12)

"This second control center enhances the resiliency of PJM's core functions as a regional transmission organization; each control center will be able to manage the PJM grid and markets in the event of an emergency affecting either site." (re: 12)

"To enhance the efficiency of PJM's dispatch operations, a Perfect Dispatch metric was developed and implemented. The goal is to help optimize the system's production cost while maintaining reliability requirements by improving the dispatch process. The tool compares actual dispatch operations against the hypothetical least-production-cost commitment and dispatch that could be achieved only if all system conditions were known and controllable in advance." (re: 12)

"The auction, for the 2011/2012 delivery year, produced a net increase in resources of 4, 238 megawatts (MW) of new generation and demand response, including more than 1,000 MW of baseload capacity." (re: 20)

"Wholesale market energy prices in PJM and other regional transmission organizations also have been a contentious issue. But developments in 2008 again demonstrated that fuel prices are the critical factor in determining locational marginal prices (LMPs) in PJM." (re: 20)

"Adjusted for the cost of fuel, prices actually have decreased in PJM over the past decade, reflecting the efficiencies that PJM's larger market and regional grid operations bring. With the decline in fuel prices that took place in the second half of 2008, LMPs in PJM's real-time and day-ahead markets dropped sharply from their levels earlier in the year." (re: 20)

PJM's Value Proposition follows. It addresses various aspects of the Commission's initial two questions, as do PJM's responses to the subsequent questions the Commission has posed..

PJM's Value Proposition

By maintaining grid reliability and realizing economies of scale over its large footprint in the Eastern Interconnection, PJM produces as much as $2.3 billion annually in savings for the region. Allocating a proportion of those benefits to Ohio on the basis of load share misses several critical points. First and foremost, reliability is regional in nature, and it is misleading to assume that Ohio's reliability benefit is equivalent to Ohio's PJM share of 9 percent.[26] Another major fallacy with the load share approach is the dubious assumption that a load-share based attribution of scale economies evident yesterday will remain valid under alternative policies driving electricity resource decisions.[27] PJM urges the Commission to consider these realities in evaluating the benefits PJM provides by maintaining regional reliability, providing economies of scale, operating its market platform and informing decision-makers of the potential outcomes of their choices on grid operations and economics.

[26] Reliability is indivisible in the same sense as is national defense.

[27] Consider, for example, the policies enacted by the Ohio General Assembly in Senate Bill 221 to promote retail access and to increase Ohio's dependence on renewable resources; and the potential impact of carbon mitigation policies under consideration at the federal level.

For each calculated savings component in this document, the calculation represents the savings that accrue to the region as a result of the integrated operation of the PJM footprint compared to the operation of the previously independently-operated control areas. It is important to note that while the majority of the savings is attributable to the efficiencies gained through operation of a larger footprint, such operation would not be possible were it not for the associated operation of the PJM electricity markets. It is safe to assume that the integrations of additional control areas into the PJM footprint would not have occurred but for PJM's operation of efficient, transparent, robust and non-discriminatory markets for capacity, energy and ancillary services. Therefore, while as detailed below, some benefits can be quantified based on the existence of the markets themselves, other benefits PJM brings to the region are the result of the operation of the larger footprint made possible by the existence of PJM's electricity markets.

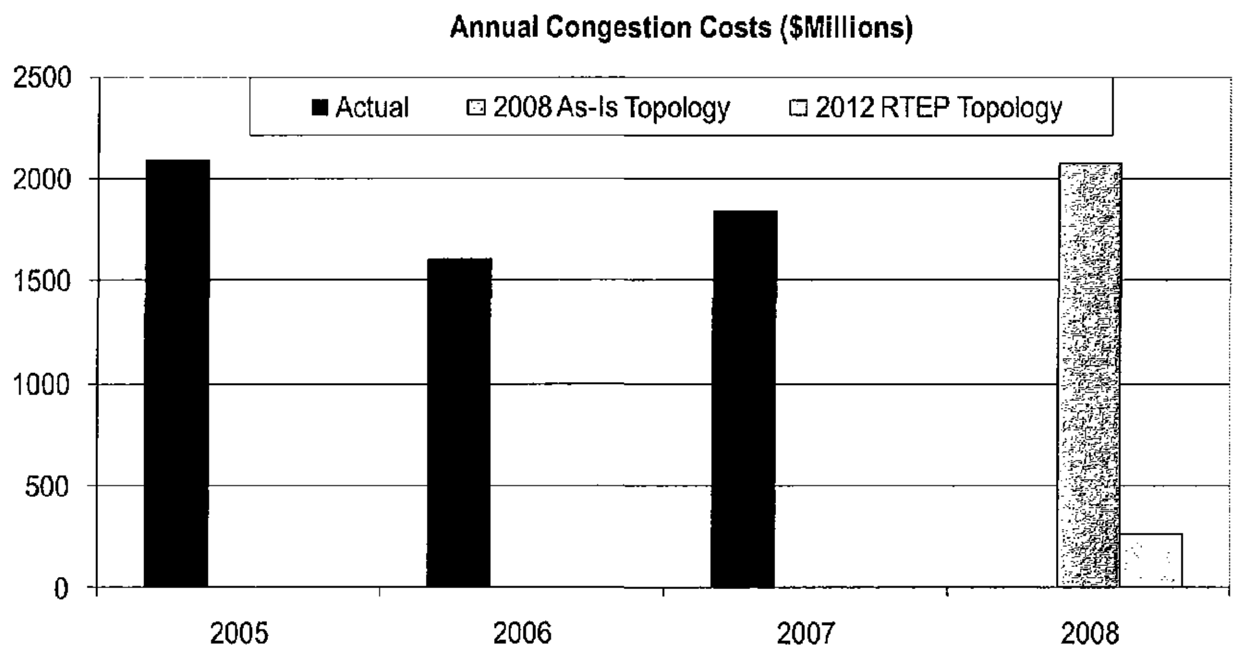
Reliability related savings: $470 million to $490 million in annual savings

Reliability savings attributable to re-dispatch. Wherever possible, PJM alleviates congestion by re-dispatching generating resource output rather than by curtailing power transactions through transmission loading relief procedures (TLRs). By reducing the need for TLRs over a wide area, PJM's narrowly targeted re-dispatch procedures resolve transmission constraints more rapidly. PJM estimates that re-dispatch enabled by the LMP platform results in annual savings of from $80 million to $100 million.

Transaction curtailments implemented under the TLR process are an extremely costly mechanism for reducing the flow on constrained transmission elements when compared to much more specifically targeted security constrained economic dispatch procedures. The TLR process relies on the administrative curtailment of wide area, control area to control area transactions in order to maintain flow within established ratings on transmission system elements. These transaction curtailments do not in any way reflect the economic desires of the market participants by which they are scheduled, but rather are conducted in a priority order determined by the length and firmness of the transmission service on which they are tagged. Because of the nature of this priority order, the curtailed transactions may have a five percent or smaller flow impact on the transmission constraint being controlled, and transmission system operators may therefore be required to implement thousands of MW of curtailments to achieve the necessary relief on constrained facilities. PJM, on the other hand, relies on security constrained unit commitment and economic dispatch in order to maintain transmission system reliability. This mechanism minimizes out-of-merit dispatch by economically re-dispatching resources that have the greatest impact on a constrained facility first, and has significantly reduced the transaction curtailments PJM has been required to implement in order to maintain transmission facilities within limits. From 2004 to 2007, PJM transaction curtailment requests were reduced in excess of 1,000,000 GWh. PJM production cost simulation results in conservative estimates that the savings realized from the reduction in these inefficient transaction curtailments is between $80 million and $100 million/year.

There are additional reliability benefits to the reduced reliance on the NERC TLR procedure that are less quantifiable in terms of dollars. Because TLR relies on curtailments of interchange transactions, relief from implementation of that process on a transmission facility cannot begin to be realized until at least 30 minutes after the constraint is recognized. This is because an inherent time delay exists between when a constraint is recognized, applicable transaction curtailments can be determined by the Reliability Coordinator, and those transaction curtailments can actually be implemented via the NERC electronic transaction tagging system. Additionally, because the transactions being curtailed under the NERC TLR process are scheduled from control area to control area, it is impossible for the Reliability Coordinator to know specifically which generation resources will respond to accomplish the curtailments. The relief actually provided can therefore vary from that which was expected based on differences among unit-specific distribution factors on the constraint being controlled. Security constrained economic dispatch, on the other hand, sends electronic dispatch signals to individual generators within minutes of a constraint being identified. Within a few additional minutes, individual generators can respond to those signals and begin to provide relief on the constrained facility. While a monetary quantification is difficult, the reliability benefit of providing much more timely and targeted relief on transmission constraints is undeniable.

Reliability savings attributable to congestion reduction resulting from regional transmission planning. The PJM Regional Transmission Expansion Planning (RTEP) Process has resulted in billions of dollars of actual and planned transmission infrastructure development in the PJM footprint. In addition to their reliability benefits, the transmission upgrades planned under the PJM RTEP Process have resulted in significant economic efficiencies. As of 2007, PJM incorporates economic efficiency analysis into the regional planning process in order to supplement the reliability criteria on which transmission infrastructure development decisions are based. PJM's analysis indicates that for the year 2012 alone, the transmission upgrades in the current RTEP will result in over $390 million of increased economic efficiency for the footprint. This single-year value provides a conservative estimate of the annual economic value of the PJM reliability planning process, because this value can be expected to accrue year over year into the future, and will increase with every transmission project constructed and implemented in future years. The following exhibit illustrates the impact of the 2012 RTEP by contrasting 2008, "as-is" transmission system topology with forecasted 2012 transmission system topology.



Generation Investment Savings: $640 million to $1.17 billion annually

If the previously integrated control areas were operated independently, each individual control area would need to carry a certain amount of installed capacity reserve. Various aspects of operating an RTO market allow for a reduced reserve margin compared to that which would be necessary without the larger RTO market. Multiplying the avoided MW of generation infrastructure development times the cost of installing additional capacity yields a savings of between $640 million and $1.17 billion/year.

<u>Generation investment savings attributable through reduced capacity reserve requirements</u>. If the previously integrated control areas were operated independently, each individual control area would need to carry a sufficient amount of installed capacity reserve to meet its own reliability requirements. The increased load diversity achieved by operation of the larger PJM footprint allows PJM to carry a smaller amount of installed reserve capacity compared to the total amount that would be required if each control

area calculated its own requirement. While the reserve requirements in the areas encompassing the integrated control areas may have been lower than the current PJM Installed Reserve Margin, total actual installed reserve levels were significantly higher than PJM's current margin. The result of the PJM capacity construct will be to ensure that only the level of reserves required to economically meet the required reserve level will continue to be compensated. In addition, the incentives provided by the transparent, single clearing price energy market have directly resulted in improved generator performance and reduced outage rates, further decreasing the required reserve margin. The PJM average forced outage rate has decreased over two percent since the initiation of the PJM LMP Energy Market in 1998. Multiplying the MW of reduced reserve margin times the cost of installing the additional capacity that would be required yields a savings of between $366 million and $900 million/year.

Generation investment savings attributable to demand resource reliability commitment. Additional generation infrastructure investment savings is realized through the commitment of demand response resources to provide reliability assurance. If reliability can be maintained through the commitment of demand resources to reduce load during times of system peaks, the cost of building generation facilities to provide the additional required capacity is avoided. The PJM Reliability Pricing Model (RPM) provides a mechanism by which generation, demand response, energy efficiency resources and transmission can compete on equal footing, thereby providing a transparent mechanism by which demand response can participate in the capacity market. Through this mechanism, the quantity of demand response that is committed to providing capacity in the PJM footprint has increased to 7047 MW in the 2012/2013 delivery year. The resulting avoidance of infrastructure development represents savings to the region of approximately $275 million/year.

Energy Production Cost Savings: $340 million to $445 million annually

PJM's centralized dispatch of the numerous resources over its expanded territory produces significant efficiencies and cost savings compared with the previous operation of independent control areas across the region. The increasing effectiveness of PJM's dispatch operations also has reduced operating reserve costs. PJM's simulation of the production cost impact of the expanded PJM RTO operation resulted in savings of between approximately $240 million and $345 million annually. In addition to this base production cost savings, PJM has also enhanced the efficiency of its dispatch over the three years of operation since the integration of AEP and Dayton Power and Light, resulting in an additional savings exceeding $100 million/year.[28]

PJM's study produced an annualized, production cost analysis of the savings attributable to operating a single footprint compared to operation of the previously independently operated control areas. As is typical in such analyses, hurdle rates were utilized to simulate the ability of these independent control areas to transact with the remainder of the footprint without the benefit of a centrally operated dispatch. Based on this analysis, the energy production cost impact of the expanded PJM RTO operation is between $240 million and $345 million/year. PJM has also enhanced the efficiency of its dispatch since these integrations. The benefits of this enhanced efficiency are realized in reduced make-whole payments to generators known as Balancing Operating Reserve costs. Reduction in these costs has resulted in an additional savings exceeding $100 million/year.

In addition to the production cost benefit of operating the larger footprint, the transparent price signals produced by the operation of the LMP Energy Market enable demand response to actively participate and compete directly with generation. Because the value of energy is made transparent in real time, demand responders that otherwise would have no incentive to reduce demand can do so in response to real time prices, thereby competing directly with generation resources. This ability, although difficult to quantify as an annual average value, has the effect of reducing the cost to all load by reducing real time prices, most particularly during times of high system demand.

Ancillary Services Market Savings: $134 to $194 million annually

By operating markets for ancillary services across its footprint, PJM achieves economies in providing services essential to the reliability of the electric system. Synchronized reserve service supplies electricity if

[28] Over the last year, PJM has implemented a Perfect Dispatch protocol that is estimated to have achieved an additional $30-40 million in production cost savings not reflected in the PJM Value Proposition summarized herein. Perfect Dispatch refers to the hypothetical least production cost dispatch and commitment, achievable only if all system conditions (demand, unit availability/performance, interchange, transmission outages, etc.) would be known and controllable in advance. Ideally, a perfect dispatch would provide a simultaneous optimized solution of all parameters and factors under PJM control in the day-ahead and real-time environments. Production cost optimization can include energy and ancillary services market co-optimization based on locational reserve requirements or by direct generation outage inclusion as contingencies. In 2007 PJM began work with PowerGEM to build a software package to simulate prior days operations utilizing known quantities of system conditions to determine the Perfect Dispatch solution for the day.

the grid has an unexpected need for more power on short notice, while regulation helps match generation and load by correcting for short-term changes in electricity use that might affect system stability.

Synchronized Reserve market procurement savings. PJM maintains Synchronized Reserves in the amount of the largest single contingency in the entire RTO footprint. Prior to their integration in to PJM, ComEd, AEP, Dayton, Allegheny, Duquesne and Dominion were operated as individual control areas, and synchronized reserves were carried separately in those control areas. PJM has analyzed the cost of maintaining the additional synchronized reserve that would be required if these systems were still operated independently. The calculation recognized that there were reserve sharing arrangements in place, which reduced the amount of synchronized reserve each control area was required to individually maintain. The resulting savings attributable to the reduction in required synchronized reserve is approximately $30 million/year.

Regulation market procurement savings. PJM procures Regulation ancillary service from the entire pool of resources available across the entire PJM footprint. If the control areas that have been integrated into PJM instead operated independently, the same total amount of Regulation would be required, but each control area would be limited to procuring the service from the resources available within each control area's boundaries. PJM has conducted a simulation of the resulting cost of procuring Regulation if it were once again procured from resources within the boundary of those previously independent control areas. The analysis resulted in a savings in the cost of procuring Regulation of between $104 million and $164 million/year.

3. Are the RTOs' locational marginal pricing (LMP) policies providing value to Ohio's consumers?

RTO LMP policies provide value to Ohio's consumers by assuring the reliable operation of the high voltage transmission system, and establishing the lowest wholesale electricity prices consistent with reliable operations. By facilitating the ability of system operators to re-dispatch generators to maintain system reliability, PJM's utilization of LMP ensures its ability to operate the bulk power system consistent with regional grid reliability standards, at the lowest overall total cost for operating the system reliably. LMP does so by fulfilling the following conditions necessary to support reliable dispatch: (1) RTO spot prices must reflect the market value of the energy each generator produces at the time and place it is produced; (2) the spot market price must be consistent with the generators' offers and the demand-response providers' bids; (3) in the face of transmission congestion, spot market prices must reflect locational differences caused by the congestion; and (4) spot market prices must reflect the tradeoffs between producing energy and providing operating reserves.[29]

The PJM pricing system is tightly integrated with the real-time generation dispatch function: LMP-based markets reinforce system reliability by providing price signals that incentivize electric generator and demand response behaviors consistent with reliable grid operations. By enabling system operators to re-dispatch generators to maintain reliable operations rather than to impose inefficient Transmission Loading Relief (TLR) procedures, LMP assures the transmission system can accommodate requested energy deliveries, which in turn are scheduled to maximize electricity transfers for the benefit of all customers in the region. Prior to PJM's adoption of an LMP-based system, generators' decisions to increase or decrease production were informed by zonal rather than nodal prices, and the system was less reliable.

LMP-based market systems reveal the cost to serve the next megawatt of load at a particular location. As uniform cost systems they provide incentives for suppliers to be as efficient as possible. Because they are set under competitive conditions and reflect actual operating conditions and energy flows, LMP-based market systems provide for the most efficient use of the transmission system.

PJM's competitive LMP-based wholesale market reveals the real moment-to-moment cost of consuming electricity (the wholesale market price) by revealing the price at which a large numbers of buyers and sellers are willing to contract. The reference point of a dynamic market price is an extremely important input for decision-makers seeking to mitigate the volatility inherent in the wholesale market price by entering into retail regulatory contracts (i.e. retail tariff rates) or bilateral contracts between electricity producers and consumers.

LMPs provide market participants with valuable information to guide their behavior in the short term, and to inform investment decisions in the longer term. As is the case with other commodities, sales at the prevailing wholesale electricity market price enable the electricity producer to assess market demands and decide whether to increase or decrease production in the short term. Decisions of consumers who face

[29] See *How RTOs Establish Spot Market Prices (and How This Helps Keep the Lights On)*, John Chandley, LECG LLC, September 2007, for a thorough discussion of the manner in which LMP pricing is uniquely suited for assuring bulk power grid reliability.

LMP prices to curtail consumption are supported in PJM's LMP-based market with programs which enable them to capture the savings associated with their decision to curtail. With the deployment of Advanced Metering Infrastructure, the LMP pricing system will enable consumers to adjust their demand in response to a real-time price signal. The price signals produced by LMP-based systems inform decisions to invest in generation, transmission, and demand-side resources by revealing the presence and degree of congestion on the transmission system.

The LMP system makes all market participants partners with the RTO in maintaining grid reliability through price signals. PJM's goal is to be certain, to the extent possible within reliability constraints, that at any moment in time the least expensive set of generating resources is operating to serve the regional electricity demand. To assure this cost-effective outcome, PJM's market rules price energy from the spot market in a manner that incentivizes generators to come on line and follow dispatch signals. At the same time, the LMP system ensures that loads will pay enough to cover this cost while paying no more than the cost they are willing to pay, as indicated by their bids. Spot market prices provide the correct incentives for all market participants to do what the RTO needs them to do maintain the reliability of the bulk power system.

In addition to playing a fundamental role in maintaining short-term reliability of the high-voltage electricity transmission system, PJM's LMP market design facilitates innovation in advanced and alternative resources including renewable energy sources, demand response solutions, and energy efficiency.
For all of these reasons, every ISO and RTO in the nation is using or implementing an LMP market design to ensure electricity reliability and efficient markets.

LMP market design has been subject to significant criticism over the past decade on several counts. Some critics have suggested that its uniform price design unjustly rewards generators that are paid more than their marginal costs of operation. Others have suggested high and volatile wholesale electricity prices are an unjust artifact of market design that has diminished the willingness of generators to enter into long-term bilateral contracts. Neither criticism acknowledges the instrumental purpose LMP serves in assuring system reliability at the lowest cost consistent with reliable operations.[30]

[30] See Cramton and Stoft, *Uniform Price Auctions in Electricity Markets,* March 18, 2006, for detailed discussion of the reliability-based merits of uniform price markets and an explanation that even when LMP system energy costs fluctuate above and below long-run average costs, on average customers pay only long-run costs.

Proponents of alternative market designs such as "pay-as-bid" ignore the fact that a generator bidding into a pay-as-bid market will change its bidding behavior and no longer bid at its short-run marginal generation cost, as generators do in PJM's LMP-based market. Rather than bidding at short-run marginal cost, generators that are paid-as-bid will bid "strategically" to reflect what they believe their power is worth by guessing what the demand for power will be, what the available supply will be, and what the ultimate clearing price will be. The likely result is higher wholesale market prices. More important from the perspective of system reliability, a pay-as-bid system increases operational uncertainty resulting from fluctuating bidding patterns that can jeopardize reliable and efficient grid operation by failing adequately to value supply in times of shortage, and undermining investment incentives.

Fluctuations of input generation fuel prices is the primary factor affecting changes in LMPs,[31] and the 2008 SOM Report makes clear that a high 2008 LMP level results from underlying fuel prices and not market power. The IMM concludes that the results of the PJM Energy Markets are competitive and that the mark-up component of load weighted average LMP of only three percent is strong evidence of competitive behavior. The 2008 SOM Report shows that the mark-up component of LMP is negative on average at LMP below $60/MWh, encompassing 55 percent of all hours in 2008.[32] PJM's own examination of the mark-up behavior of coal and gas units (regardless of whether they were on the margin or not) reveals that coal units, on a consistent basis, were on average offering just below their costs. Gas units on average were bidding just over their marginal costs. The overall mark-up bidding behavior of coal and gas units reaffirms the competitiveness of PJM's Energy Markets.

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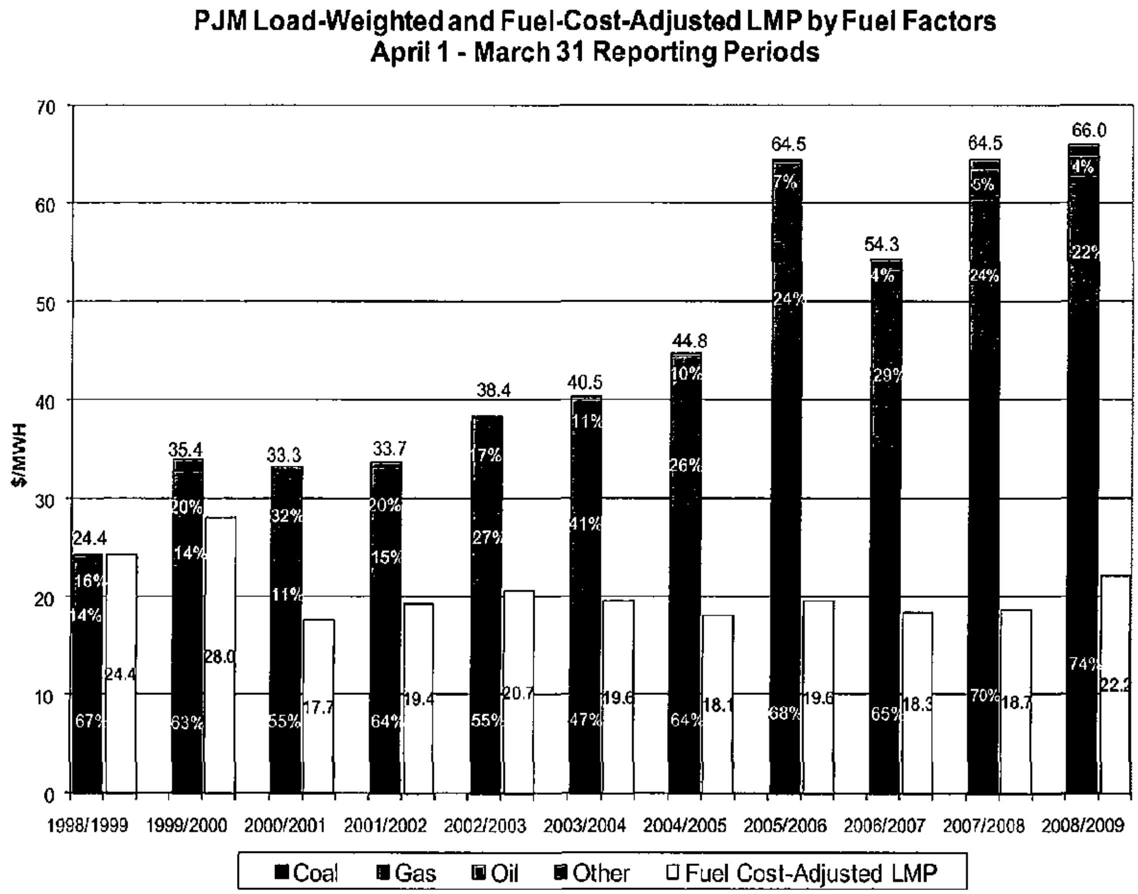
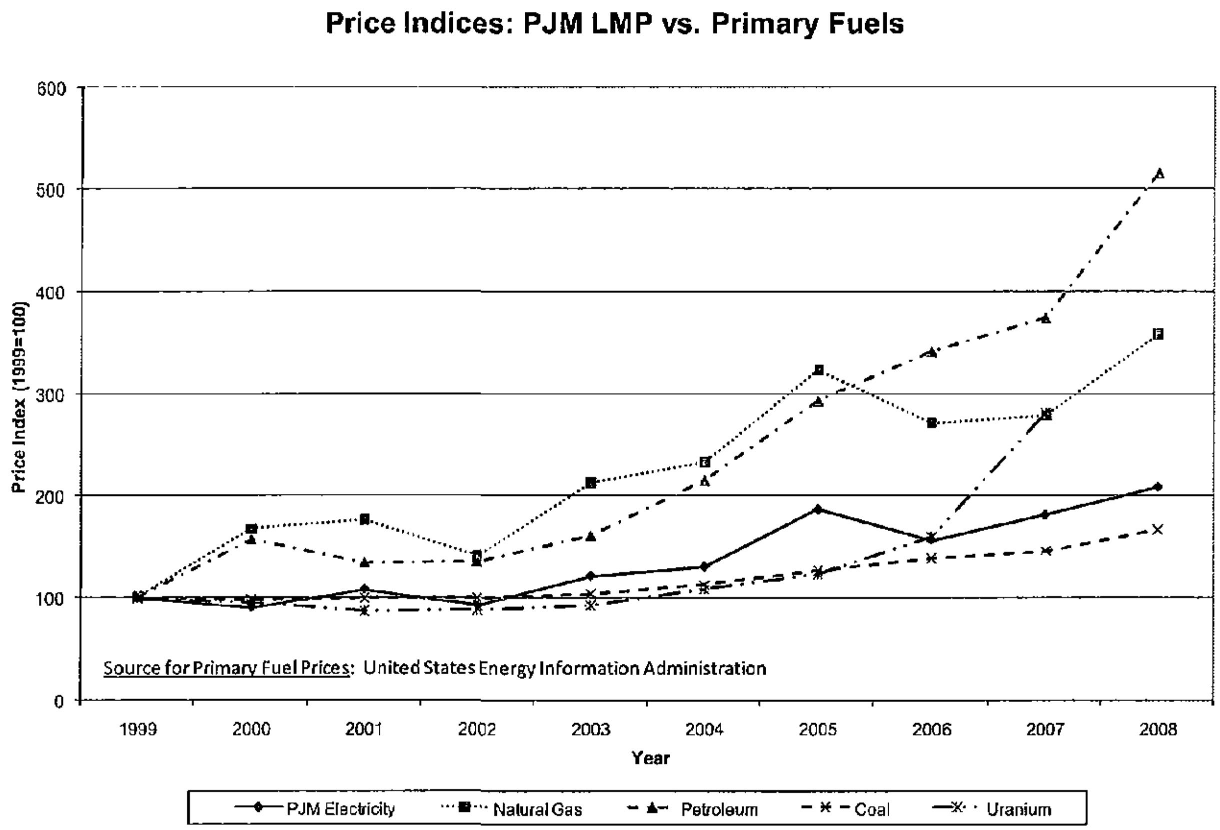
[31] Gas and coal prices accounted for 87.9 percent of PJM's load-weighted, average LMP in 2008. See *2008 State of the Market Report for PJM, Volume 2:Detailed Analysis,* March 11, 2009, p. 61.

[32] 2008 SOM Report at p. 8.

The following exhibit displays average LMP prices within PJM on an annual basis over the last decade, as well as the corresponding fuel-price adjusted LMP. The latter has declined significantly from a decade ago with increased efficiencies of PJM's wholesale electricity market stemming from shared diverse resources and the coordination of regional operation.



The following exhibit provides a comparison between LMP indices and fuel indices since 1999 and compares the PJM LMP price trend with the trend for coal price, clearly illustrating that the PJM LMP price index has tended to most closely follow the price of coal. Said another way, coal sets PJM's marginal price most of the time.



Steep energy fuel price decreases commencing in July 2008 have put downward pressure on PJM electricity prices in both the spot and forward markets. Load-weighted average PJM LMP dropped to $75.76 per MWH in August from $102.95 in June and $97.32 in July. The PJM Western Hub peak contract price for July 2009 dropped from $139 per MWh to $95 between early July and mid-September, for a 32% decrease. The following exhibit depicts the trends in PJM Western Hub July 2009 (peak) contract electricity futures prices, which have been falling significantly over the past ten months.

The LMP system enables system operators to re-dispatch generation facilities to avoid reliability violations, rather than rely on the previous regime of inefficient power curtailments resulting from Transmission Loading Relief (TLR) procedures. In the late 1990's, the electricity industry's dependence on TLRs to maintain system reliability led to significant power disruptions in the Midwest and elsewhere. In fact, those disruptions spurred the development of the LMP market design, with the objective of assuring reliable bulk power system operations. The number of Level 2-and-above TLRs called by PJM has decreased significantly since the integration in of AEP and Dayton Power and Light among other transmission owning utilities into the RTO, and decreases in TLRs observed in the Midwest ISO coincide with the implementation of Market-to-Market coordination between the Midwest ISO and PJM.[33]

4. Are the RTO's ancillary services markets and the integration or co-optimization of those markets with the RTOs' energy markets efficient and providing benefits to Ohio's consumers?

Ohio consumers benefit from PJM's ancillary service markets and the co-optimization of Day-Ahead Scheduled Reserves (DASR) with PJM's day-ahead Energy Market: ancillary services support the reliable operation of the transmission system as it moves electricity from generating sources to retail customers. PJM's ancillary service market results are consistent with competitive outcomes, and co-optimization of supplemental, 30-minute operating reserves has resulted in extremely low market clearing prices. In real-time PJM operates two markets for ancillary services, Regulation and Synchronized Reserve (SR).

Regulation provides for the continuous balancing of generation, load and interchange to maintain system frequency at sixty cycles per second. Regulation is accomplished through the raising or lowering of output by generation resources or the raising or lowering of loads by demand resources in response to electronic signals determined and distributed by the system operator. The telemetry requirements including the ability to receive and respond to these signals, called Automatic Generation Control ("AGC") signals, are the same for demand resources and generation resources. Load-serving entities (LSEs) can meet their obligation to provide regulation to the grid by using their own generation, by purchasing the required regulation under contract with another party or by buying it on the Regulation Market.

PJM believes the results of the Regulation Market are consistent with competitive outcomes.[34] For the entire year 2008, the load-weighted average cleared offer price was $11.94/MWh for regulation under a regime where there is no must-offer requirement and the only market power mitigation from January 1st to

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[33] Information available on NERC's website.

[34] Regulation Market results for 2008 were not determined to be either competitive non-competitive, because the IMM relied upon estimates of what cost-based offers would be rather than upon supplier submitted cost-based offers. The IMM believes Regulation Market results will be competitive with the application of the Three Pivotal Supplier Test, which was implemented in the Regulation Market in December 2008 along with the requirement to submit cost-based regulation offers.

November 30th was a $100/MWh offer cap and mandatory cost-based offers for the two largest suppliers. This load-weighted average cleared offer price is less than the $12 cost adder allowed in cost-based offers beginning December 1st. The cleared offer price rarely exceeded $20/MWh in 2008. PJM has also examined regulation offer behavior compared to the submitted cost-based offers from December 2008 when the Three Pivotal Supplier Test (TPST) and associated market mitigation was in place. PJM found the vast majority of regulation offers, 78.8 percent, were competitive (meaning at- or below-cost) in 2008 using the December 2008 weighted average of cost-based offers as a benchmark. When viewed together with the price performance of cleared offer prices, it appears the Regulation Market outcomes were competitive.

The level of the weighted average cleared offer prices, which do not include lost opportunity costs of being in the Energy Market that fluctuate with fuel and energy prices, has remained extremely stable since PJM implemented one common market for regulation on August 1, 2005. The cleared offer prices of regulation for the remainder of 2005 were $13.16/MWh, $11.36/MWh in 2006, $12.06 in 2007, and $11.49 in 2008. Moreover, prior to having one combined Regulation Market, there were instances of insufficient regulation supply in the PJM Western Region (this includes AEP and Dayton Power & Light) which caused PJM to idispatch resources inefficiently to maintain the regulation requirements.[35] Consequently, the combined Regulation Market has maintained stable cleared offer prices while enhancing reliability especially in the western portion of PJM's system.

SR service supplies electricity if the grid has an unexpected need for more power on short notice. The power output of generating units supplying SR can be increased quickly to supply the needed energy to balance supply and demand; demand resources also can bid to supply SR by reducing their energy use on short notice. LSEs can meet their obligation to provide SR to the grid by using their own generation, by purchasing it under contract with another party or by buying it on the SR Market.

In PJM, SR service is broken up into two Tiers: (a) Tier 1 SR, which is provided by resources that are on-line (*i.e.*, synchronized to the grid), following economic dispatch, and capable of decreasing load or increasing output within ten minutes of a call for SR in response to an SR Event; and (b) Tier 2 SR, which is

[35] See *2005 State of the Market Report*, PJM Market Monitoring Unit, March 8, 2006, pp. 257-258.

extra SR capacity committed in excess of Tier 1 capacity, also synchronized to the grid and operating at the direction of PJM to meet SR requirements. The SR Market is the mechanism by which SR is committed. Qualified demand resources and generation resources are eligible to participate as Tier 1 or Tier 2.

SR has been procured by region in PJM. Most often, PJM must purchase Tier 2 SR in the Mid-Atlantic Region. This market is a cost-based offer market due to concerns with structural market power Since 2005, prices inclusive of lost opportunity costs in the Mid-Atlantic Region have remained relatively stable at $13.29/MWh in 2005, $14.57/MWh in 2006, $16.28/MWh in 2007, and $10.68/MWh in 2008. In the Western Region (or the rest of the region encompassing the geography of the Reliability First Corporation, which includes AEP and Dayton Power and Light), the Tier 2 market rarely clears as there is almost always enough Tier 1 capacity to meet SR Requirements. The number of hours in which there was a non-zero price for SR in the western part of PJM was less than one percent in 2005 and 2007, six percent in 2006, and five percent in 2008.

Supplemental, 30-minute operating reserves are generating and demand side response resources that add to supply and can be loaded within 30-minutes of being called. The purpose of these supplemental reserves is to ensure differences in forecasted loads and expected generator forced outage rates do not result in adverse reliability impacts. Prior to June 1, 2008 PJM scheduled these reserves separately after the Energy Market cleared.

In order to improve overall market efficiency and consistent with the RPM settlement, PJM incorporated supplemental, 30-minute reserve scheduling into its Day-ahead Energy Market in a process named Day-ahead Scheduled Reserves (DASR) that began June 1, 2008.[36] Each month thereafter, the monthly load-weighted average clearing prices in this market are less than $1/MW in all months, and the load-weighted average for the seven months of operation is $0.26/MW.

PJM agrees with the IMM assessment in the 2008 SOM Report that the DASR Market results were competitive, although the IMM notes that the DASR Market is not structurally competitive based on the results of the Three Pivotal Supplier Test (TPST).[37] The IMM further recommends that the TPST and cost-

[36] See PJM Interconnection, L.L.C., 117 FERC ¶ 61,331 (2006).

[37] 2008 SOM Report, p. 332.

based offer mitigation be implemented for the DASR Market.[38] The TPST is a measure of structural market power and utilizes a threshold for eligible supply of offers within 150 percent of the market clearing price to be included in the test. Given the extremely low clearing prices of the DASR Market, PJM believes this threshold may be preventing the test from providing a meaningful reflection of structural market power in this market. PJM is in agreement that implementing the TPST and associated cost-based offer mitigation would provide assurances to market participants that market results are driven by competitive pressures. However, PJM does not believe the 150 percent threshold for eligible supply was designed with such extremely low clearing prices in mind. If the market clearing price is zero, then even an offer of $0.01 is not considered relevant according to the test. In the case of the DASR market, PJM recommends that the threshold value determining eligible supply be revisited in the stakeholder process if the PJM members elect to incorporate the TPST and cost-based offer mitigation.

DASR Market clearing prices are based on resource offer prices and the recovery of opportunity costs associated with reduced energy production. Successful DASR bidders are paid for supplemental reserves provided and also are compensated for foregone energy revenue. The addition of the lost opportunity energy cost payment has the effect of making DASR an attractive product relative to the Energy Market for units from the baseload and mid-merit cost segments, not just high-cost, peaking units. Lower cost units no longer have to choose between providing energy or reserves, because providing reserves is as least as profitable as providing energy.

The exhibit on the following page provides strong evidence that co-optimization has delivered on its promise of lower overall system cost, and lower costs for supplemental, 30-minute reserves. At 2008 year-end reserve prices have dropped to about $0.10/MWh.

[38] 2008 SOM Report, p. 305.

DASR Market Data			
Month	Average Required (MW)	Average Price ($/MWH)	Total Costs ($)
Jun-08	1,622	$0.91	$1,085,406
Jul-08	4,484	$0.55	$1,813,545
Aug-08	6,044	$0.36	$1,600,026
Sep-08	5,162	$0.23	$873,064
Oct-08	4,825	$0.10	$354,811
Nov-08	5,194	$0.09	$343,751
Dec-08	5,633	$0.09	$372,805
Total		$0.26	$6,443,408

5. Are the RTOs' market monitoring and mitigation policies effective in ensuring competitive prices and providing value to Ohio's consumers?

PJM's market monitoring and mitigation policies are effective in ensuring competitive prices consistent with reliable grid operations, thereby providing value to Ohio's consumers. PJM's Markets are monitored in real time by the IMM to detect the exercise of market power. Any time that a generation unit is dispatched out-of-merit order to relieve congestion, and that generator fails the TPST, automated market power mitigation software mitigates that generator's offer to a level equal to cost plus ten percent. Generation units are required to provide and update cost schedules to PJM, and the IMM is authorized by FERC to audit the cost schedules submitted. Automated and real time monitoring for the exercise of market power assures that small transactions will not go unnoticed or unmitigated and will not have large and unforeseen impacts on long term prices. Market power mitigation incorporated in PJM's market design provides market participants and other interested stakeholder assurances that prices resulting in PJM's Markets are driven by competitive forces. However, the frequency with which cost-based offer mitigation occurs is low and analysis of bidding behavior by suppliers (*see response to Question 3 above*) shows strong evidence of competitive behavior.

The IMM's 2008 State of the Market Report (2008 SOM Report) certifies that PJM's Energy Market is competitive, as well as its Capacity , Synchronized Reserve Market, Day Ahead Scheduling Reserve Market, and FTR Auction Market. The competitiveness of PJM's Energy Market is reflected in the IMM's findings regarding the extent and degree of price markups over costs in offers submitted by generators. The IMM determined that in 2008, load-weighted unit markup indices were negligible. According to the 2008 SOM Report, the markup component for units setting LMPs was $2.04 per MWH, or 3 percent. The markup was $3.27 per MWh during peak hours and $0.74 per MWh during off-peak hours. The MMU observed that "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."[39]

PJM agrees with the IMM that there is a continuing need for robust market mitigation rules to prevent the exercise of market power and ensure efficient, competitive outcomes in PJM's Markets, while providing appropriate price signals when new investment is necessary. PJM supported the implementation in 2008 of the recommendations made by the IMM in the 2007 State of the Market Report (2007 SOM Report), as these provide further assurances to market participants and other interested stakeholders that the results in PJM's Energy and Ancillary Service Markets are competitive. Moreover, PJM supports the use of the TPST and marginal cost offer capping in the DASR Market with appropriate adjustments to fit the DASR context. Competitive results are ensured through a market power mitigation strategy that caps offers of suppliers when they are found to possess structural market power as determined by the TPST.[40] In the context of scarcity (*and as discussed below in the response to Question 12*), PJM and the IMM are in concurrence that the scarcity pricing mechanism should be redesigned such that market power mitigation need not be suspended during scarcity conditions in order to reach prices that signal scarcity.

In the 2008 SOM Report, the IMM recommends the retention and/or application of the TPST or other market power screens to determine when markets are structurally non-competitive.[41] Moreover, to prevent the exercise of market power when there is a finding of structurally non-competitive markets, the IMM recommends continuing the offer capping of units at their marginal cost. The markets where the TPST and/or offer capping based on marginal or incremental cost are in effect include the Day-Ahead and Real-Time Energy Markets; the Synchronized Reserve Market;[42] the Regulation Market as of December 1, 2008;

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[39] *2008 SOM for PJM, Volume 2: Detailed Analysis*, p.8, Monitoring Analytics LLC, March 11, 2009.

[40] If a market participant possesses structural market power, this does not mean that participant has exercised market power or even has an incentive to exercise market power. Rather structural market power is an indication of a tight supply demand balance and/or a high concentration in ownership. See *PJM's Comments Regarding the 2007 State of the Market Report Issued by the PJM Market Monitoring Unit* April 11, 2007 at http://www.pjm.com/documents/~/media/documents/reports/comments-2007-som-report.ashx at pp.3-5.

[41] 2008 SOM Report at 2.

[42] TPST is not used to trigger offer capping in the Synchronized Reserve Market. Offers are always subject to offer caps of cost plus $7.50/MWh. See PJM OATT, Attachment K-Appendix, Section 1.10.1A (j).

and the RPM Capacity Markets. Subject to PJM's comments above regarding the DASR context, PJM supports the IMM's recommendations regarding the TPST and offer capping of units at their marginal cost when there is a finding of structurally non-competitive markets.

PJM submits that offer capping statistics presented in the 2008 SOM Report provide evidence of market competitiveness and the necessity of locational price signals through LMP and RPM. According to the SOM Report, market-wide offer capping of generating units was limited to 0.2 percent of unit hours in the Day-ahead Energy Market and 1.0 percent of units hours in the Real-time Energy Market.[43] Of the units that are frequently offer capped, only seven units with greater than 400 hours of operation (less than five percent of all available hours in a year) are offer capped more than ten percent of their run hours.[44] PJM has run a more granular analysis of offer capping by location and by unit type to show where and to what types of units offer capping is taking place. Recall that offer capping in the PJM Energy Market only occurs with a finding of structural market power as determined by the TPST, which is only run when there are binding transmissions constraints in the PJM Energy Market. Additionally, offer capping is only applied to units which are not yet running based on economics at the direction of PJM. The following exhibit shows offer capping statistics by locational deliverability area (LDA) and unit type,[45] and reveals that combustion

[43]2008 SOM Report Table 2-5 at 18.

[44] SOM Report Table 2-6 at 18.

[45] EMAAC includes the JC, PSEG, RECO, AECO load zone in New Jersey; the PECO zone in Pennsylvania; and the DPL zone in Delaware, Eastern Maryland, and the Delmarva Peninsula of Virginia. SWMAAC includes the BGE and PEPCO zones in Maryland and DC. WMAAC includes the PPL, Penelec, and Met Ed zone in Pennsylvania. RTO includes all other zones

turbines (CTs) are the most offer capped unit type as a percentage, a phenomenon occurring primarily in EMAAC, SWMAAC, and WMAAC[46]. Not coincidentally, these areas observe a great deal of congestion associated with west-to-east flows across PJM.

	CT		Steam		Diesel	
LDA	**Offer capped MW**	**Offer capped run hours**	**Offer capped MW**	**Offer capped run hours**	**Offer capped MW**	**Offer capped run hours**
EMAAC	23.1%	22.9%	0.1%	0.4%	3.4%	8.9%
RTO	5.5%	5.6%	0.0%	0.1%	3.3%	1.8%
SWMAAC	49.6%	53.1%	0.4%	0.6%	3.3%	1.8%
WMAAC	64.3%	52.0%	0.4%	0.6%	22.5%	2.5%

The IMM's role will soon be changing given the mandates of Order No. 719. PJM filed its Compliance Filing on April 29, 2009, and an errata on May 1, 2009, in Docket No. ER09-1063, setting forth its proposed OATT and Operating Agreement revisions. In Order No. 719, among other things, FERC required that RTOs ensure that their MMUs have access to resources, market data and enough personnel to ensure that RTOs carried out their duties, that they report to the board of directors of the RTOs, and that RTOs revise their open access transmission tariffs to clarify their MMU's and RTO's functions.[47]

To comply with Order No. 719, and to be consistent with the mandates of Order No. 719, PJM modified its OATT and Operating Agreement as specifically delineated in detail in its Order No. 719 Compliance Filing. Generally, PJM indicated in its filing that its IMM already has appropriate access to resources, market data and enough personnel to monitor whether PJM carried out its duties in accordance with its OATT, that its IMM reports to the PJM Board of Managers and that PJM management does not have oversight over the IMM. PJM proposed amendments to its OATT to incorporate a minimum ethics standard, as required by Order No. 719. The bulk of the compliance filing as relates to market monitoring was dedicated to revising the OATT to clarify the IMM's and PJM's roles and responsibilities consistent with the requirements of Order No. 719. However, until such time as FERC issues its final order in the referenced docket, the IMM will continue to perform the functions that it has traditionally performed for PJM as set forth in the OATT,

[46] See 2008 SOM Report at pp. 39-40 for a brief discussion of frequently mitigated units.

[47] Order 719 at pp. 2-8.

Operating Agreement, and PJM Manuals. Furthermore, regardless of FERC's final decision on PJM's Order No. 719 Compliance Filing, PJM affirms that it remains committed to a strong, independent market monitor, and to robust and effective market mitigation policies.

6. Are the RTOs' resource adequacy requirements and the resulting capacity markets (or, in the case of PJM, its Reliability Pricing Model and Fixed Resource Requirement) reasonable and providing benefits to Ohio's consumers? Are these policies effective in promoting needed resource investment and long-term contracts which could help finance such investment? Do these policies promote an appropriate level of investment that is consistent with the needs and preferences of Ohio consumers?

PJM's Reliability Pricing Model (RPM) provides regional reliability benefits to Ohio's consumers by assuring that enough electricity resources are available to satisfy planning reserve margins required to maintain a Loss of Load Expectation (LOLE) in PJM of 1 day in 10 years. RPM is designed to provide incentives to ensure investment in electricity resources that will be forthcoming to maintain reliability of the regional grid in the future to that standard, and the Fixed Resource Requirement (FRR) is a feature of the RPM framework consistent with its reliability objective that provides an opt-out alternative for Load Serving Entities that elect it. The RPM construct has produced impressive results to date in the delivery of committed Capacity Resources, as described below.

RPM replaced a former capacity construct in PJM that provided insufficient incentives for investment in electricity resources and arguably encouraged the exercise of market power, as capacity suppliers could withhold resources and force capacity buyers to pay unwarranted high capacity prices. This was the case because the former construct's fixed, vertical demand curve enabled capacity withholders to shift the supply curve to the left, causing it to intersect with the demand curve at a higher capacity price. RPM features a downward sloping demand curve, the Variable Resource Requirement (VRR) curve that more accurately reflects the increasing value of capacity when it is short as well as its value when capacity is long, and mitigates price volatility associated with the former vertical demand curve. RPM also improved on the design of the former capacity construct by redefining the period when capacity must be available. RPM's three-year forward auction and incremental auctions allow newly constructed capacity, equivalent demand response and energy efficiency resources, as well as merchant transmission facilities to compete with existing traditional supply-side Capacity Resources, thereby expanding the number of potential competitors vying to supply capacity in the auctions. RPM introduced a locational aspect to capacity procurement in PJM to reflect that fact that the value of capacity is a function of limitations on the transmission system's ability to deliver electricity into an area and differences in the need for capacity in various areas of PJM.

RPM has been subject to unjust criticism since its inception in 2007 stemming in large part from perceptions that capacity suppliers are being paid more than capacity is worth[48], and that RPM has not spurred the investment in additional capacity that it was designed to stimulate. Those concerns have been proven vacuous in view of a comprehensive evaluation of RPM's design and its results-to-date conducted in 2008, and the results of the 2009 RPM Base Residual Auction (BRA), discussed below. Over the long-run, the design of PJM's VRR curve limits payments for capacity to cost-of-service level returns by establishing the cost of new entry net of energy and ancillary service revenues (Net CONE) as the target level of planning reserves required.[49]

In 2008, PJM submitted to FERC a report on the structure and performance of the RPM (Brattle Report) construct authored by the Brattle Group (Brattle).[50] The Brattle Report concluded that the first five BRAs (up to and including the BRA in May 2008), had been successful in achieving the reliability and economic objectives of the RPM as defined in the RPM settlement agreement reached in September 2006. The Brattle Report noted that RPM had attracted and retained more than 14,500 MW of resources that likely would not have been available otherwise, including new generation, existing generation uprates, new demand response, decreases in committed net exports, withdrawn requests to deactivate plants, and cancelled or deferred retirements of generating plants. According to the Brattle Report, RPM had helped stimulate the proposed construction of numerous new generation projects, of which approximately 33,000 MW were already eligible to offer into future RTO auctions, and had assisted in retaining more than 20,000 MW of existing resources that would not be financially viable in the absence of capacity prices. The Brattle Report noted that to attract and retain these resources and improve reliability levels, customers had paid

[48] Although capacity prices were artificially low in from 2004 to 2006, the annual price of capacity in 2001 was $100.43 per MW-day in unconstrained regions of PJM, comparable to the price results from the 2008 RPM auction for the 2011-2012 planning year. Price results from the 2009 RPM auction for 2012-2013 are $16.46 per MW-day.

[49] See *PJM's Reliability Pricing Mechanism: Why It's Needed and How It Works*, John Chandley, LECG LLC, February 2007 for a lucid explanation of the rationale behind RPM, its primary features, and how the VRR curve limits total ratepayer payments over the long run to what they would have been if the same level of resources were acquired under traditional cost-of-service regulation.

[50] *See Review of PJM's Reliability Pricing Model*, June 30, 2008, filed in *PJM Interconnection LLC, Docket Nos.ER05-1410-000 and EL05-148-000 et als.*

capacity prices that are consistent with resource adequacy conditions and the administratively-determined marginal cost of capacity for the RTO—the Net CONE of approximately $170/MW-day. In addition to affirming the reasonableness of its principal design, the Brattle Report offered a number of suggestions to improve RPM's performance.[51]

Subsequently[52] FERC determined that eight issues should be considered for possible changes where feasible, for implementation in time for the May 2009 BRA,[53] and ultimately accepted[54] several significant changes to RPM design that impacted either the demand or the supply curves for the 2012/2013 BRA as compared with the 2011/2012 BRA,[55] including the designation of energy efficiency resources as supply resources eligible to bid into the auction.

The 2012/2013 BRA results reflect burgeoning participation by Demand Resources and significant participation from Energy Efficiency Resources and renewable resources. The Resource Clearing Price in

[51] Brattle's recommendations were to change certain market rules and design elements to increase the pool of resources able to offer capacity into the RPM, for example by allowing energy efficiency and price-responsive demand resources to be reflected in the RPM on a more timely basis; revise penalties imposed on electricity providers that do not fulfill their capacity commitments; improve processes to maintain and cost-effectively provide reliability in constrained LDAs; change how capital expenditures may be included in suppliers' offers; and reevaluate reliability targets and improvements to the processes used to determine the Net CONE.

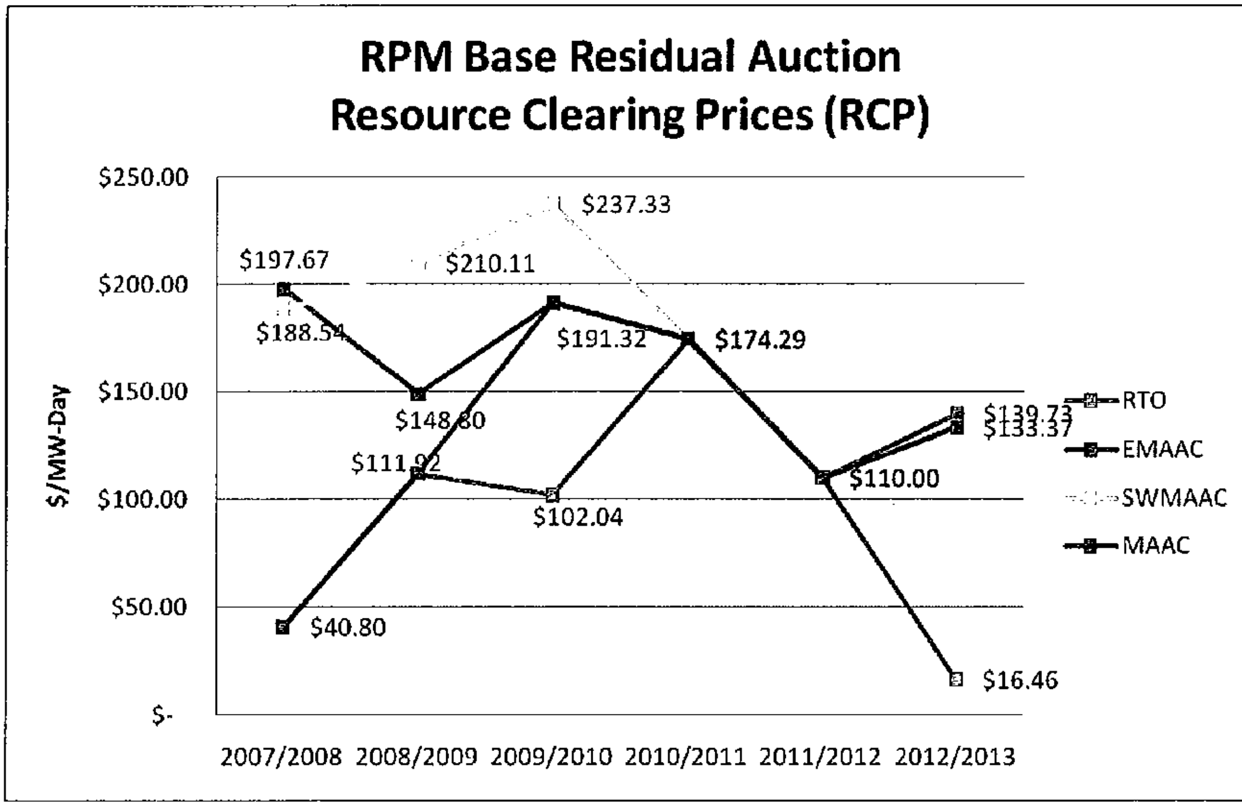
[52] In the interim, FERC issued an order addressing the Brattle Report and directing further proceedings, and PJM filed with FERC a report on its stakeholder process considering the Brattle Report's and other stakeholder recommendations as well as proposed changes to its OATT and Regional Reliability Agreement. PJM also filed a Settlement Offer and Settlement Agreement by PJM and certain parties, primarily load interests and state commissions after formal FERC settlement proceedings were terminated.

[53] The eight issues identified by FERC were use of historical averages of energy and ancillary services revenue to determine Net CONE; rules for the participation of energy efficiency and demand-side resources in the RPM auctions; market power and mitigation rules; reliability requirements/criteria and defining LDAs; must-offer rules relating to the exclusion of capacity due to the sales cap imposed on Fixed Resource Requirement entities and partial-year ownership and availability; performance penalties; incremental auctions; and length of forward commitment for new Capacity Resources.

[54] *PJM Interconnection, L.L.C.* Order Accepting Tariff Provisions in Part, Rejecting Tariff Provisions in Part, Accepting Report, and Requiring Compliance Filings, 126 FERC ¶ 61,275 (2009).

[55] The Demand Curve was impacted by the following changes: inclusion of load in the Duquesne Zone, 56 percent increase in CONE values for the RTO; replacement of the ILR forecast and with a Short Term Resource Procurement Value; and changes to the criteria for modeling LDAs. The Supply Curve was impacted by discontinuation of the ILR product; eligibility of Energy Efficiency and Planned External Generation as Supply Resources; modifications to generation sell offer changes; extension of the New Entry Pricing Adjustment Option to Existing Generation Resources planning to make large capital expenditures for the Delivery Year; and modifications to Avoidable Cost Rate default values.

the transmission zones located in Ohio was $16.46 per MW-day, a decrease of $93.54 per MW-day from the 2011-2012 BRA..[56] These results represent a 21.2 percent reserve margin; however when the Fixed Resource Requirement (FRR) load is taken into account, the actual reserve margin for the entire RTO is 20.9 percent. The following exhibit displays RPM BRA Resource Clearing Prices for the unconstrained and constrained LDAs in PJM over the course of the last six BRAs.



The FRR alternative allows load serving entities to meet a fixed capacity obligation via self-supply rather than be subject to RPM's Variable Resource Requirement (VRR).[57] As such, load serving entities opting-out of the VRR obtain certainty in terms of the capacity costs they face, as well as in planning to meet future load. On the other hand, FRR capacity resources are subject to a five-year term, and the FRR

[56] The RPM auction price was lower because of a growth in the available capacity and a decline in demand. Supply increased because of the significant increases in new capacity from demand resources and energy efficiency resources. Demand declined due to a 446 MW decrease in the RTO preliminary peak load forecast.

[57] FRR commitments have remained relatively constant over the course of the last five BRA auctions, fluctuating within a range of 24,953 MW to 26,302 MW.

option is available only to load serving entities that serve the entire load in the area where the FRR applies. The Brattle Report raised several other issues concerning conditions to which FRR entities are subject that in its judgment raised concerns about the inefficient exclusion of capacity from RPM auctions.

The Brattle Report observed that under the RPM rules, an FRR entity with capacity in excess of its reliability requirement was required to set aside a "buffer" for uncertainties in load group and generation ability: the lesser of 3 percent of its UCAP obligation or 450 MW. The provision was intended to address uncertainty associated with the load forecast and with forward capacity resource availability.[58] The Brattle Report noted that a three percent buffer is larger than the implicit buffer created by centering the VRR curve at one percent above the target reserve margin, and concluded that FRR entities should not require a 3 percent buffer because they can cover capacity resource deficiencies through the purchase of replacement capacity in incremental auctions.

The Brattle Report also noted that an FRR entity faced a sales cap on how much of its excess capacity could be offered in RPM auctions, equal to the lesser of 25 percent of each FRR entity's UCAP obligation or 1300 MW. The Brattle Report concluded that the sales cap results in a short-term increase in capacity clearing prices in RPM auctions, and in lower RTO-wide reliability.[59] The Brattle Report therefore recommended that PJM consider increasing the amount of capacity FRR entities could offer into RPM auctions by eliminating the sales cap and consider reducing the threshold amount of capacity that FRR entities must hold before offering excess capacity into the RPM auctions to one percent, and requiring them to cover any deficiencies bilaterally or in the incremental auctions.

Stakeholders rejected the idea of eliminating the sales cap, on the grounds that it was not coupled with a "must offer" requirement for an FRR entity's capacity, and the concern that absent "must offer" or another regulatory mechanism, an FRR entity with significant capacity might be able to exercise market power by varying the amount of capacity offered in the auction. Stakeholders also chose not to pursue removal of the 3% buffer, as this provides added assurance that the FRR Entity will be able to address the load uncertainty and the availability of future supply.

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[58] Of the three percent buffer, two percent addressed load uncertainty and one percent addressed future supply resource availability.

[59] Brattle Report, pp. 73-75.

The Brattle Report also proposed revising penalties for those not fulfilling capacity requirements, including FRR entities. Brattle suggested that the high penalty rates were overly punitive, and that reducing the rate could still provide certainty that resource adequacy would be maintained during the delivery year. PJM stakeholders have subsequently endorsed reductions in the penalty rates associated with non-performance in RPM from being based on CONE or two times a Resource Clearing Price value determined through RPM auction to being based on 1.2 times a Resource Clearing Price value determined through the RPM auctions. This change was approved by FERC in their March 26, 2009 Order on RPM.

The total quantity of Demand Resources offered into the 2012/2013 BRA represented an increase of 496 percent over the Demand Resources that offered into the 2011/2012 BRA. Of the 9,847 MW of total Demand Resources that offered in this auction, 7,047.3 MW cleared and will be awarded capacity payments. Of this cleared amount, 4,723.8 MW (67 percent) was located in the constrained regions of PJM, consistent with investment in Demand Resources in higher price regions where such response is needed.

The following exhibit provides a summary of the Demand Resources and Energy Efficiency resources that offered and cleared by zone in the 2012/2013 BRA.

AECO	11.7	78.9	67.2	7	75.1	68.1
AEP	24.2	1352.7	1328.5	14.6	710.8	696.2
APS	88.6	582.4	493.8	57.3	272.9	215.6
BGE	628.3	1370.6	742.3	595.8	1312.9	717.1
COMED	158	1049	891	127.3	658	530.7
DAY	25.4	405.6	380.2	15.3	112.3	97
DOM	155.8	1237.9	1082.1	105.9	494.7	388.8
DPL	58.9	289.6	230.7	43.8	283	239.2
DUQ	0	190.8	190.8	0	74.8	74.8
JCPL	55.4	362.7	307.3	46.4	321.9	275.5
METED	23.8	267.2	243.4	14.3	252	237.7
PECO	131.3	581.2	449.9	103.2	496.4	393.2
PENELEC	27.1	286.1	259	16.2	276.3	260.1
PEPCO	150.9	485.1	334.2	144.8	460.8	316
PPL	63.4	832.9	769.5	42.2	783.3	741.1
PSEG	49.6	472.9	423.3	30.8	460.1	429.3
RECO	0	2	2	0	2	2
Total	1652.4	9847.6	8195.2	1364.9	7047.3	5682.4

*All MW Values are in UCAP Terms

The total quantity of Demand Resources offered into the 2012/2013 BRA represented an increase of 496 percent over the Demand Resources that offered into the 2011/2012 BRA. Of the 9,847 MW of total Demand Resources that offered in this auction, 7,047.3 MW cleared and will be awarded capacity payments. Of this cleared amount, 4,723.8 MW (67 percent) was located in the constrained regions of PJM, consistent with investment in Demand Resources in higher price regions where such response is needed. The following exhibit illustrates the Generation, Demand Resources, and Energy Efficiency Resources offered and cleared in the RTO over the last five BRAs, reflected in Unforced Capacity MW amounts.

[redacted]					
Internal PJM Capacity	166,037.9	167,026.3	168,457.3	169,241.6	179,791.2
Imports Offered	2,612.0	2,563.2	2,982.4	6,814.2	4,152.4
Total Eligible RPM Capacity	**168,649.9**	**169,589.5**	**171,439.7**	**176,055.8**	**183,943.6**
Exports / Delistings	4,205.8	2,240.9	3,378.2	3,389.2	2,783.9
FRR Commitments	24,953.5	25,316.2	26,305.7	25,921.2	26,302.1
Excused	722.0	1,121.9	1,290.7	1,580.0	1,732.2
Total Eligible RPM Capacity - Excused	**29,881.3**	**28,679.0**	**30,974.6**	**30,890.4**	**30,818.2**
Remaining Eligible RPM Capacity	**138,768.6**	**140,910.5**	**140,465.1**	**145,165.4**	**153,125.4**
Generation Offered	138,076.7	140,003.6	139,529.5	143,568.1	142,957.7
DR Offered	691.9	906.9	935.6	1,597.3	9,535.4
EE Offered	0.0	0.0	0.0	0.0	632.3
Total Eligible RPM Capacity Offered	**138,768.6**	**140,910.5**	**140,465.1**	**145,165.4**	**153,125.4**
Total Eligible RPM Capacity Unoffered	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**

*RTO numbers include all LDAs.

The following exhibit illustrates the cumulative increase in new generation capacity by fuel type since the inception of RPM (June 1, 2007). New combined cycle units account for the largest increase by fuel type for 2012/2013. Coal units and incremental nuclear upgrades have cleared nearly 3,000 MW of base load capacity, adding to the diversity of generation supply committed via RPM.

	Delivery Year	CT/GT	Combined Cycle	Diesel	Hydro	Steam	Nuclear	Solar	Wind	Total
New Capacity Units (ICAP MW)	2007/2008			18.7	0.3					19.0
	2008/2009			27.0					66.1	93.1
	2009/2010	399.5		23.8		53.0				476.3
	2010/2011	283.3	580.0	23.0					141.4	1027.7
	2011/2012	416.4	1135.0			704.8		1.1	75.2	2332.5
	2012/2013	403.8	585.0	7.8		36.3			75.1	1108.0
[illegible]	2007/2008					47.0				47.0
	2008/2009					131.0				131.0
	2009/2010									0.0
	2010/2011	160.0		10.7						170.7
	2011/2012	80.0				101.0				181.0
	2012/2013									0.0
[illegible]	2007/2008	114.5		13.9	80.0	235.6	92.0			536.0
	2008/2009	108.2	34.0	18.0	105.5	196.0	38.4			500.1
	2009/2010	152.2	206.0		162.5	61.4	197.4		16.5	796.0
	2010/2011	117.3	163.0		48.0	89.2	160.3			577.8
	2011/2012	369.2	148.6	57.4		186.8	292.1		8.7	1062.8
	2012/2013	231.2	164.3	14.2		193.0	126.0		56.8	785.5
	Total	2835.6	3015.9	214.5	396.3	2035.1	906.2	1.1	439.8	9844.5

Taken together, these exhibits demonstrate that the RPM framework is stimulating investment in a diverse portfolio of Supply and Demand Resources to assure that regional reliability is maintained in the long-term.[60]

7. Are RTOs effective in facilitating transmission planning and needed transmission investments that benefit Ohio's consumers? Are they effective in facilitating transmission planning and investment that may be needed for the development of renewable energy resources?

Ohio's consumers benefit directly from the long-term reliability assurances provided by PJM's facilitation of transmission planning and investment. PJM conducts a long-range Regional Transmission Expansion Planning (RTEP) process that identifies what changes and additions to the grid[61] are needed to ensure reliability[62] and the successful operation of the wholesale markets underpinning system reliability. Contractual arrangements with PJM's transmission owners[63] assure that transmission system enhancements necessary to maintain regional reliability will be constructed upon the granting of state siting authority. With regard to transmission planning and investment that may be needed for the development of renewable energy resources, PJM has taken a lead role in identifying the policy challenges that federal authorities must overcome to assure that Ohio's and the nation's renewable electricity resource objectives will be satisfied.

PJM's transmission planning process is fully compliant with current FERC requirements set forth in Order 890 that establish eight planning process principles: coordination, openness, transparency, information exchange, comparability, dispute resolution, regional participation, economic planning studies, and cost

[60] A comprehensive account of the results of the 2012/2013 RPM Base Residual Auction is available at http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/2012-13-base-residual-auction-report-document-pdf.ashx.

[61] RTEP transmission upgrades and enhancements cover a range of power system elements: circuit breaker replacements to accommodate increased current interrupting duty cycles, new capacitors to increase reactive power support, new lines, line reconductoring, new transformers to accommodate increased power flows and other circuit reconfigurations and upgrades to accommodate power system changes.

[62] PJM assesses its system as being compliant with the thermal, reactive, and stability requirements of all applicable standards including NERC Standards TPL-001, 2, 3 and 4 for the period 2009 through 2023.

[63] *See* PJM Consolidated Transmission Owners Agreement, Rate Schedule FERC No. 42.

allocation for new projects. While FERC determined most of the features of PJM's RTEPP to be in compliance with the standards it established in Order No. 890, PJM expanded its stakeholder process in 2008 to comply with the Order, thereby enhancing coordinated, open and transparent planning and building on a well-established planning process codified in Schedule 6 of PJM's Operating Agreement. In compliance with Order No. 890, PJM's planning stakeholder process now provides a sub-regional basis for direct stakeholder participation in the planning process, from initial assumption setting stages through review of planning analyses, violations, and alternative transmission expansions. In that regard, PJM invites the active participation of the Commission on the Western PJM Sub-Regional RTEP Committee. PJM also modified its planning protocols to comply with FERC's Order No. 890 by clarifying its process for evaluating local transmission projects ("Supplemental Projects") and addressing how they fit into the regional planning process.

Each year, PJM develops a Regional Transmission Expansion Plan documenting the results of planning studies conducted throughout the previous year and the rationale for transmission system upgrades that have been identified.[64] PJM's RTEP process includes both five year and 15-year dimensions. Five-year-out planning enables PJM to assess and recommend transmission upgrades to meet forecasted near-term load growth and to ensure the safe and reliable interconnection of new generation and merchant transmission projects seeking interconnection within PJM. The 15-year horizon permits consideration of long-lead time transmission options that often comprise larger magnitude transmission facilities that more efficiently and globally address reliability issues, as well as market efficiency[65]. Typically, these are higher voltage upgrades that simultaneously address multiple NERC reliability criteria violations at all voltage levels.[66]

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[64] *PJM 2008 Regional Transmission Expansion Plan,* February 27, 2009.

[65] PJM's RTEP process includes market efficiency analysis to determine which reliability upgrades, if any, have an economic benefit if accelerated; identify new transmission upgrades that may result in economic benefits; and identify economic benefits associated with modification to reliability-based enhancements already included in RTEP that when modified would relieve one or more economic constraints.

[66] Among other backbone transmission solutions under consideration, the PJM 2008 Regional Transmission Expansion Plan notes the consideration of two transmission projects located in-part in Ohio: a South Canton Tap – Keystone – Sunbury Transmission Line, and a Kammer – TMI Transmission Line. See *PJM 2008 Regional Transmission Expansion Plan,* February 27, 2009, p. 108.

The RTEP process systematically and objectively evaluates proposed transmission upgrades, generation interconnections and demand-response projects to make sure that compliance with reliability criteria is maintained. The process accommodates not only expansion projects proposed by transmission owners, typically electric utilities, but also merchant generation and transmission projects that are financed by private investors instead of utilities. PJM's open and extensive review process ensures that all interested parties, including state regulatory agencies, have an active role in planning for future electricity supply and reliability needs.[67] To date, transmission investments authorized under PJM's RTEP since 2000 total over $13.2 billion, with more than 22,000 megawatts of new generation being interconnected to the PJM grid

.As evolving energy policy is implemented to increase the utilization of renewable resources and/or to mitigate carbon dioxide emissions, Ohio consumers will continue to benefit directly from PJM's RTEPP process. With the Midwest ISO, PJM is already deeply involved in interregional transmission planning initiatives that resolve reliability issues associated with interconnection requests at boundaries, address broader interregional baseline reliability issues, and consider interregional economic impacts. These include the PJM/MISO Joint Operating Agreement, the PJM/TVA/MISO Joint Reliability Coordination Agreement, and the PJM/MISO/SPP/TVA Joint Coordinated System Plan Initiative.[68] PJM is taking a prominent position in the recently organized Eastern Interconnection Planning Collaborative, comprised of 17 bulk power system planning authorities in eastern North America that have agreed to work jointly on forming an Eastern Interconnection Planning Collaborative (EIPC) for the sole purpose of developing an interconnection-wide view and analysis of regional transmission plans. Formation of the EIPC is premised on the realization that analyzing future transmission needs, especially as they relate to renewable resources, will necessitate a multi-regional approach to transmission planning that considers interconnection-wide impacts. Expanding on the existing planning expertise and protocols already employed on a regional basis in the Eastern Interconnection is the most efficient and timely means of accomplishing this goal.

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[67] PJM Operating Agreement, Schedule 6, Section 1.3(b) and 1.3(d).

[68] PJM is also cooperating with the US Department of Energy to provide planning and operating technical review input to its Interregional Wind Study effort; enhancing planning collaboration with the North Carolina Transmission Planning Collaborative and the NYISO; and has Joint Operating Agreements in place with Progress Energy and the NYISO.

Despite these initiatives, without additional guidance from FERC to address how much and where transmission should be built to realize public policy objectives such as increased reliance on renewable resources and mitigation of the impact of climate change, RTO planning processes do not authorize transmission providers to employ criteria other than reliability planning and economic congestion relief to facilitate the large-scale integration of new renewable resources such as wind into the bulk power system. PJM recently recommended that FERC consider whether a third set of metrics (in addition to the reliability and economic congestion driven metrics already embodied in PJM's planning processes) is needed if the Commission's goal is to drive aggressive integration of renewable resources based on public policy benefits. PJM also clarified the policy issues and trade-offs associated with any expansion of the current planning process to embrace planning protocols and cost allocation methodologies targeted to the aggressive deployment of new renewable resources on to the grid.[69]

8. Are RTO policies and practices effective in facilitating long-term contracts between load serving entities and generation developers or suppliers that may be needed to support the construction of additional base load generation facilities?

PJM is not directly responsible for the operation of forward bilateral markets, which unlike the spot market are not implicated in the assurance of short-term system reliability. Nevertheless, because electricity market participants have voiced concerns that they are unable to enter into long-term contracts for the purchase of power in the PJM footprint, and because the acrimony engendered by differing perceptions of the viability of long-term contracting has the potential to undermine wholesale market design and thereby threaten bulk power system reliability, PJM has taken a keen interest in addressing those concerns, as has FERC in Order No. 719.

PJM sponsored two Long-Term Contracting Forums in 2007 and 2008 designed to identify and overcome obstacles interfering with long-term contracting. While a number of stakeholders reported having successfully entered into long-term contracts, others articulated obstacles including difficulties hampering the development of new generation.[70] Many of those reported successes for relatively shorter terms of one

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[69] *Statement of Michael J. Kormos to Support Oral Testimony Presented at the March 2, 2009 FERC Technical Conference*, Integrating Renewable Resources Into the Wholesale Electric Grid, Docket No. AD09-4-000.

[70] Siting problems, historically inadequate revenue streams, congestion, financing challenges and uncertainty about governmental carbon mitigation requirements and costs were cited as impediments to the development of new generation, as well as the substantial cost of new generation in the context of worldwide demand for infrastructure projects and rising fuel costs.

to three years, attributing the timeframe to less perceived risk due to the ability to see forward market prices on established indices.

The Forums revealed that some buyers remained disenchanted with RTO market design and expressed concern that paying generators the market clearing price has created a windfall that is not being reinvested in infrastructure. This perception does not appear to consider all of the relevant facts. The general consensus from the Forums was that long term contracts of up to three years were readily available; however contracts beyond three years were less available due to uncertainty related to issues such as the potential for carbon legislation and other environmental regulations. Those uncertainties resulted in differing buyer and seller expectations about the forward price curve, tied to sellers' desire to price a variety of risks into their contracts that are not readily quantifiable mutually by buyers and sellers. At the time, the concern of market buyers was reinforced by the impact of rising fuel input prices and emission control costs, and retail rate shock occasioned by the expiration of retail rate freezes in several states served by PJM.

FERC expressed its desire in Order No. 719 to "improve transparency in the contracting process to encourage long-term contracting for electric power."[71] It required that each RTO incorporate into their web sites a bulletin board that market participants can use to post and view offers to buy or sell power on a long-term basis, *i.e.* for one year or more, and gave RTOs the leeway to allow market participants to post and view offers of less than one year as well. FERC also encouraged RTOs and ISOs to work with stakeholders to facilitate long-term contracting.

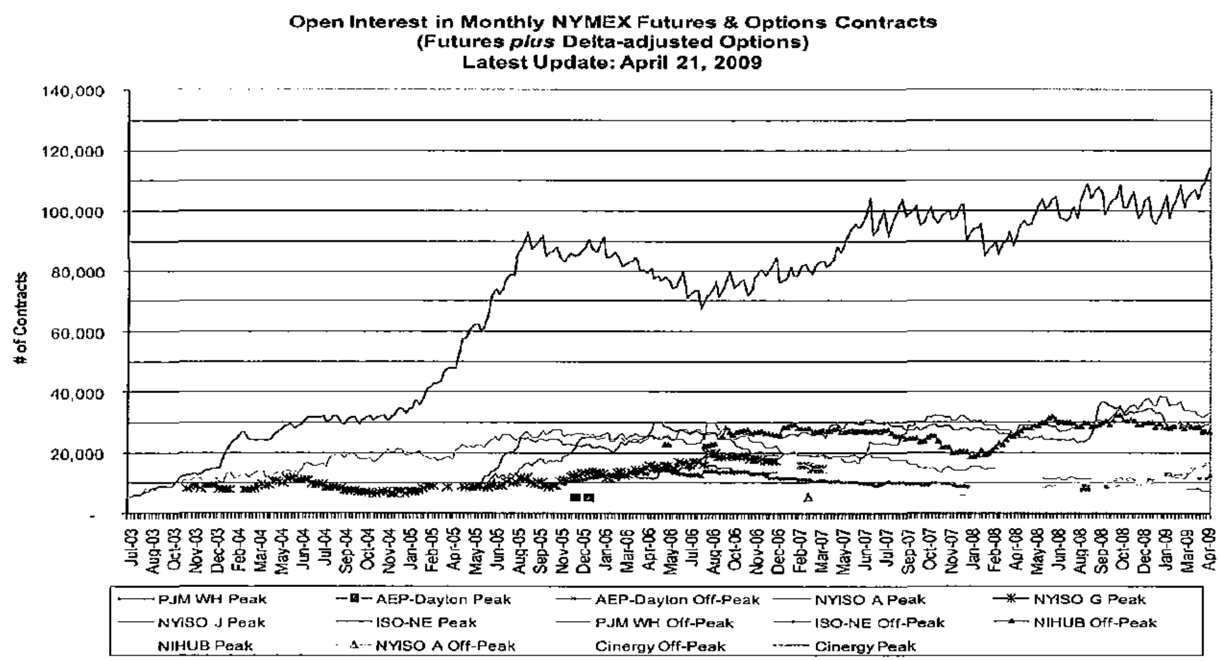
PJM worked with stakeholders after the issuance of FERC Order No. 719 to develop a proposal to host its long term contracting bulletin board on the PJM eSuite web page. As set forth in its Order No. 719 Compliance Filing,[72] PJM intends to automatically grant access to its Members to utilize the long term contracting bulletin board to post sell offers or bids to purchase power pursuant to the Authorization to Use PJM Internet Business Tools and Customer Account Manager Designation Form that every Member is required to submit to PJM to obtain the right to use PJM's eSuite Tools. Subsequent to the establishment of an account providing access to the bulletin board, PJM does not expect any interacting with entities regarding the bulletin board other than for technical issues involving use of the web site and/or eSuite

[71] Order No. 719 at p. 277.

[72] *PJM Interconnection L.L.C.*, Docket No. ER09-1063-000 (Compliance Filing), pp. 33-36.

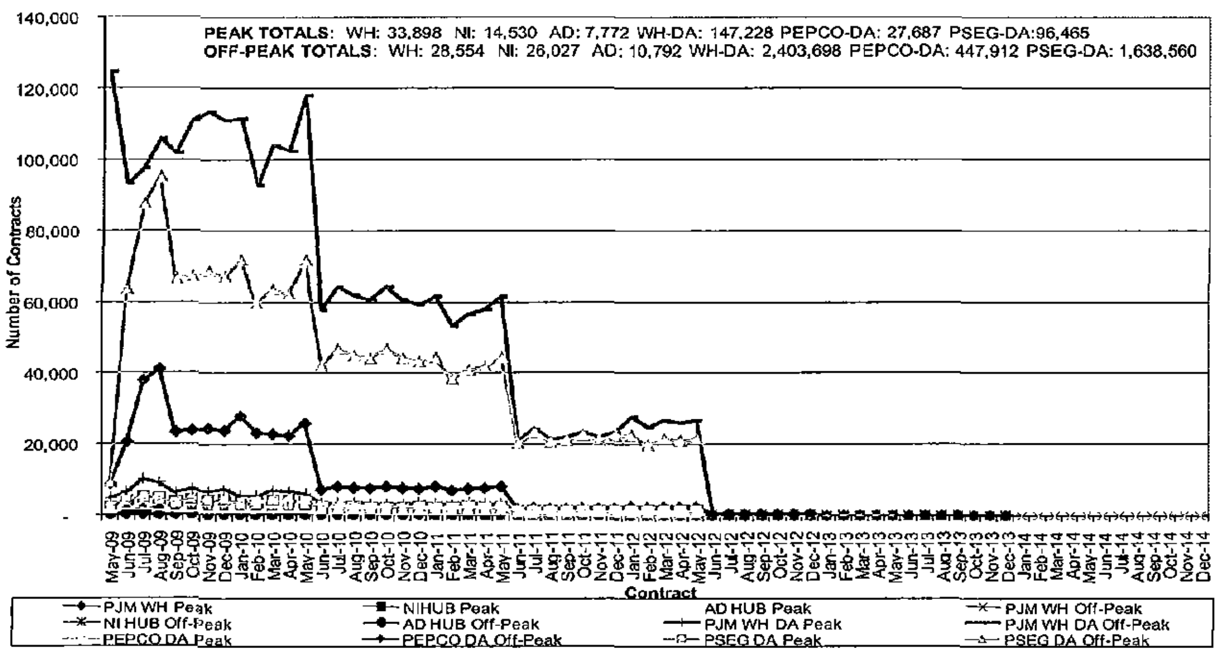
applications. To encourage greater beneficial cooperation between RTOs and to provide access to a larger pool of buyers and sellers of long term contracts for power, PJM has offered the use of its bulletin board to all the other RTOs who are members of the ISO/RTO Council and their members/market participants at no cost. Many of the RTOs have indicated that they intend to accept PJM's offer.

In addition to the PJM electronic bulletin board initiative to facilitate long-term contracting, market exchanges outside of PJM continue to facilitate futures contracts up to three years forward, providing a financial hedging equivalent to the long-term contracts facilitated by PJM's bulletin board. The New York Mercantile Exchange (NYMEX) has traded PJM Western Hub and other PJM hub contracts for real-time peak and off-peak power. These contracts, particularly Western Hub, have been traded more liquidly than other RTO contracts on a consistent basis over time as seen in the exhibit below.



Confidence in PJM's markets and a demand for financial instruments to hedge against day-ahead LMPs and to account more explicitly for location led NYMEX, on December 8, 2008, to launch peak and off-peak PJM day-ahead contracts for hubs (including Western Hub and AEP-Dayton Hub) and most delivery zones within PJM. The contract size for the day-ahead contracts is double those of the real-time contracts (5 MW compared to 2.5 MW). Open interest in these markets has already exploded. Most of the activity in these recently launched contracts has been for the off-peak contracts, rather than peak power as can be seen in the following exhibit. PJM staff is in the process of investigating the reason for so much off-peak activity compared to peak activity, but it is clear that there is greater interest in general for the day-ahead contracts than for the real-time contracts.

OPEN INTEREST ON MONTHLY PJM FUTURES CONTRACTS IN NYMEX
as of April 30, 2009



9. Are the RTO's transmission cost allocation methodologies and policies resulting in value for Ohio's consumers?

PJM's transmission cost allocation methodologies and policies are dictated by its regulator, FERC, and incorporated in Schedule 6 of PJM's Operating Agreement and Schedule 12 of PJM's Open Access Transmission Tariff. In 2007 and 2008, FERC issued several Orders clarifying several outstanding issues concerning the allocation of costs for existing and for new transmission facilities planned to operate at voltage levels either below 500 kV, and at 500 kV and above. The cost allocation methodologies approved by FERC are the subject of litigation in the US Court of Appeals, and Congress is currently addressing transmission cost allocation as one of the issues implicated in the clarification of the nation's energy policy moving forward. PJM awaits the outcome of deliberations in those venues, and its ultimate transmission cost allocation methodologies and policies will reflect that outcome.

FERC Opinion 494[73], issued in April, 2007, established a cost allocation methodology for new transmission facilities in PJM planned through PJM's Regional Transmission Expansion Planning (RTEP) process, regardless of whether planned for reliability or market efficiency reasons. FERC determined that the cost of new facilities operating at 500 kV and above would be allocated across the region on a load-ratio share basis, and based its decision on its judgment that the broad, regional benefits of such projects justified the region-wide sharing of costs. FERC also determined that the cost of new RTEP-planned transmission facilities operating below 500 kV will continue to be funded under PJM's "beneficiary-pays" approach, according to which those benefitting from a project must pay the project costs. With regard to existing transmission facilities and Supplemental Upgrades initiated by PJM's Transmission Owners, FERC determined they would continue to be allocated on a zonal basis. FERC found that approach consistent with the fact that existing facilities were built primarily to support load within individual transmission owner zones and continue to serve those loads.

In September 2007, in response to FERC's directive in Docket No. ER06-1271 to develop a complete methodology for performing a "beneficiary-pays" methodology providing *ex ante* certainty with respect to cost allocation for facilities planned to operate below 500 kV, PJM filed with FERC a Settlement Agreement and Offer of Partial Settlement. The Settlement proposed resolution of all issues except for matters regarding assignment of cost responsibility to merchant transmission facilities. FERC conditionally approved the Settlement in an Order issued in July, 2008.[74] FERC directed PJM to apply its distribution factor (DFAX) methodology[75] to reliability-based facilities planned to operate below 500 kV, with the exception of allocations to merchant transmission facilities.

Pursuant to the approved Settlement, cost allocation for upgrades that are economic advancements of RTEP reliability upgrades will be allocated by the DFAX method, unless the load zone LMP benefits differ more than 10 percent from the DFAX method. In this exception, the allocation will be based on the load

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[73] Opinion No. 494, Opinion and Order on Initial Decision, Docket Nos. EL-05-121-000 and EL-05-121-002, 119 FERC Paragraph 61,063, April 19, 2007.

[74] *Order Conditionally Approving Contested Settlement*, ER-06-456-013 et al., 124 FERC Paragraph 61,112, July 29, 2008.

[75] DFAX refers to the power flow impact on a monitored facility for an incremental change in system flow caused by a transmission outage or imposed transfer. DFAX is typically expressed in terms of a percentage of the transfer or flow on the outage facility that appears on the monitored facility.

zone LMP benefits for the period of time represented by the acceleration of the reliability project. A cost allocation method for new economic efficiency upgrades below 500 kV that are not previously identified as reliability upgrades is expected to be filed in the later part of 2009. The Settlement applies to assignments of cost responsibility that were pending in Docket No. ER06-456, *et al.* and also to all facilities approved by the PJM Board after June 1, 2007.

10. Are the RTOs' Financial Transmission Rights and other transmission congestion hedging policies and practices effective and providing value to Ohio's consumers?

Ohio consumers benefit from PJM's congestion hedging instruments, Auction Revenue Rights (ARRs) and Financial Transmission Rights (FTRs), which provide a mechanism to hedge the congestion price risk associated with movement of their load-serving entity's energy from generators to load. In this respect, properly selected FTRs mitigate the financial impact of unhedged congestion on the price that consumers pay for electricity supplied by the ARR/FTR holder.

PJM conducts an annual ARR allocation process, in which each PJM network transmission customer has the right to request sufficient ARRs to cover its peak load although the amount of ARRs awarded by PJM depends on total system capability. Subsequent to the allocation of ARRs, PJM conducts an FTR auction open to all market participants; the holder of an ARR has a right to the revenue[76] from the annual FTR auction for the same source-destination path.[77] ARRs can be converted to FTRs, reconfigured to FTRs for different transmission paths or time periods or held as a source of revenue. ARRs and FTRs can be traded separately from transmission service, and allow market participants to offset or bypass the congestion charges that result from the use of LMPs in the PJM market. Market participants can manage their FTR

[76] The value of an FTR in the annual FTR auction may be positive or negative.

[77] Table 8-25 of the 2008 SOM provides a congestion cost to congestion hedge comparison for the AEP and Dayton Power and Light transmission zones. The table shows that ARRs helped to hedge 84.5% and 39.9% of 2007/08 congestion costs associated with the AEP and Dayton zones, respectively. Although Table 8-25 shows that not all AEP and Dayton congestion is hedged by ARRs/FTRs, Table 7-16 of the 2008 SOM reveals that the congestion costs for these zones are not due to load paying a higher congestion LMP but instead due to generation in excess of load receiving the lower congestion LMP. Accordingly, although it appears "congestion" is incompletely hedged in the AEP and Dayton zones, the load LMPs are lower than they would otherwise be because they are on the sending side of the predominant constraints on the PJM system. The misleading appearance of unhedged congestion for the AEP and Dayton zones results from the fact that much of the congestion assigned to these zones is associated with zonal generation in excess of zonal load selling to the PJM market at local prices that are lower than the overall average PJM price.

portfolios by using PJM's web-based eFTR tool. Participants use eFTR to post their FTRs for bilateral trading as well as to participate in the scheduled monthly and annual FTR auctions.

The availability of FTRs can reduce risk and provide price certainty. FTRs are financial contracts; they do not create a physical right to energy delivery, and operate independently of actual energy deliveries. Their economic value is based on the LMPs in the Day-Ahead Market for delivery from a specified source to a specified destination. An FTR entitles the holder to a stream of revenues or charges based on the hourly energy price differences across a transmission path in the Day-Ahead Market.

Market participants can obtain FTRs in four ways. They can bid for them in PJM's recently established long-term auction, in which FTRs are available for periods from one to three years.[78] They can bid for them in the annual auction, in which FTRs for the entire transmission capability of the system are available. They can bid for them in the monthly auctions, in which leftover FTRs are sold. In these auctions, bidders can bid to buy or offer to sell FTRs for any of the next three individual months or any quarter in the balance of the current planning year. Finally, market participants can buy FTRs in the secondary market in a transaction with another market participant.

For each hour in which congestion exists on the transmission system in the Day-Ahead Market between the points specified in the FTR, the holder receives a credit – specifically, the difference in LMP between the destination and source points, multiplied by the number of megawatts (MW) in the FTR. Market participants are able to hedge against their congestion costs by acquiring FTRs that are consistent with their energy deliveries.

[78] PJM's first auction in October, 2008 for long-term FTRs cleared 23,348 megawatts of transmission rights for periods up to four years in the future. Long-term FTR auctions enable participants to hedge future congestion costs up to four years into the future, thereby fostering long-term power contracts. Prior to this auction, FTRs could only be purchased in one-month, three-month or one-year increments.

11. Are the RTOs' demand response programs, policies toward behind-the-meter generation, and other Load Modifying Resources effective and providing value to Ohio's consumers over and above state sponsored programs?

As FERC noted in its 2006 *Assessment of Demand Response and Advanced Metering,* demand response reinforces resource adequacy by providing equivalent functionality to generation or transmission services, depending on the its location relative to interconnected generation resources. "As a substitute for transmission and distribution infrastructure, demand response can reduce the need for new transmission or distribution expansion to bring generation to a local area. At minimum, demand response can provide relief for an overloaded transmission system, and defer the need for infrastructure." PJM's incorporation of Demand Resources into many of its Markets capitalizes on its substitution benefits, reinforcing regional transmission system reliability while improving market efficiency, mitigating the potential for the exercise of market power and bringing economic benefits to demand responders. Ohio consumers benefit directly from PJM's incorporation of Demand Resources into its market platform, regardless of the level of state-sponsored Load Modifying Resource programs. Demand response, the ability of customers to respond to wholesale electricity prices, is central to the effectiveness of the wholesale power markets that underpin transmission system reliability. Moreover, as consumers are allowed to respond to price (and provide additional supply), market competitiveness and efficiency is enhanced, and potential exercises of supplier market power are checked as any supplier attempting to raise price will result in a corresponding reduction in demand. As for individual consumers, incorporation of demand response into power markets provides the opportunity to control individual electricity expenditures. All of the benefits of the integration of demand response into wholesale electricity markets resonate with Ohio's legislatively-established energy policies.

PJM has been a leader in the integration of demand response into its wholesale electricity market, providing equivalent treatment for generation and demand resources.[79] Retail customers[80] have the

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[79] One of the primary objectives of FERC's Order No. 719 is to ensure that demand response is treated comparably to other resources in competitive wholesale markets, and to determine whether further reforms are necessary to eliminate barriers to demand response in organized markets. PJM and its stakeholders have worked diligently to ensure that demand resources have comparable participation opportunities to generation capacity resources in the PJM Markets, and stakeholders continue to work on potential enhancements to the incorporation of demand resources into PJM's Markets. See *PJM Compliance Filing*, Docket No. ER09-1063, April 29, 2009, and as amended May 1, 2009.

[80] Order No. 719 requires that RTOs allow end-use customer participation in their demand response programs unless the laws or regulations of a municipal, county, state or other regulatory authority having jurisdiction over

opportunity to participate in PJM's Energy, RPM, Day-Ahead Scheduling Reserves, Synchronized Reserve and Regulation Markets and receive payments for the demand reductions they make.[81]

In PJM's Interchange Energy Market, economic load response provides an opportunity to reduce electricity consumption and receive a payment when PJM LMPs are high. Participants have the choice of a day-ahead option or a real-time option. In the day-ahead option, customers[82] – in advance of real-time operations – can offer to reduce the amount of electricity they will draw from the PJM system. If the offers are accepted, they will receive payments based on the day-ahead LMPs for the reductions. In the real-time option, a CSP enables customers to reduce their usage voluntarily during times of high prices and receive payments based on real-time LMPs for the reductions. Emergency load response compensates retail customers who reduce their usage during emergency conditions on the PJM system. The energy-only option compensates retail customers who reduce their usage voluntarily during emergency conditions. Full emergency load response, in contrast, compensates retail customers with both energy and capacity payments provided to CSPs. These customers must reduce load at the direction of PJM during emergency conditions up to a maximum of 10 times during the summer months.

In PJM's RPM Market, both Demand Resources and Energy Efficiency Resources have the opportunity to participate on a basis equivalent to generation resources.. The can receive payments for being ready to reduce their electricity demand or for implementing energy-efficiency measures. The total quantity of

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the resource do not permit end-use customer participation in RTO demand response programs. On February 10, 2009, pursuant to Section 205 of the Federal Power Act, PJM filed proposed revisions to its OATT to detail the mechanics for PJM to implement the "opt-out" rules contained in Order No. 719, which is still pending before FERC.

[81] See Affidavit of Paul M. Sotkiewicz, Ph.D., for a thorough account of the opportunities that Demand Resources have to participate in the PJM Markets. *In the Matter of the Adoption of Rules for Alternative and Renewable Energy Technologies and Resources, and Emission Control Reporting Requirements, and Amendment of Chapters 4901:5-1, 4901:5-3, 4901:5-5, 4901:5-7 of the Ohio Administrative Code, pursuant to Chapter 4928, Revised Code, to Implement Senate Bill No. 221*, PUCO Case. No. 08-888-EL-ORD, Reply Comments by the Ohio Consumer and Environmental Advocates, Exhibit A.

[82] Customers participating in PJM's demand response programs do so through Curtailment Service Providers (CSPs), qualified PJM market participants who act as agents on their behalf. CSPs aggregate the demand of retail customers, register that demand with PJM, submit the verification of demand reductions for payment by PJM and receive the payment from PJM. The allocation of the payment from PJM to the CSP and the retail customer is a matter of private agreement between them.

Demand Resources offered into the May 2009 Base Residual Auction (BRA) for the 2012/2013 planning year represented an increase of 496 percent over the Demand Resources offered into the 2011/2012 BRA. Of the 9874 MW of Demand Resources offered, 7403 MW cleared and will be awarded capacity payments. Of this cleared amount, 67 percent was located in constrained LDAs, reflecting investment in demand response in the areas in PJM where such response is most necessary to maintain system reliability. Energy Efficiency Resources – projects that involve the installation of more efficient processes or systems exceeding then-current building codes, appliance standards, or other relevant standards at the time of commitment – were permitted to be offered as Capacity Supply Resources for the first time in the 2012/2013 BRA, and of 653 MW offered, 569 MW cleared.[83]

PJM added the capability of accepting bids for demand reduction in the Synchronized Reserve Market and the Regulation Market in 2006. Demand Resources must provide metering information at no less than a one minute scan rate surrounding a call for synchronized reserves. CSPs that bid demand reductions into the Regulation Market must meet all of the requirements of regulation service, including the real-time telemetry requirement.

As of year-end 2008, there were more than 6,000 commercial and industrial facilities with a demand greater than 100 kW and more than 45,000 small commercial and residential sites participating in demand response in PJM.

PJM's believes that the most significant benefits of demand response will occur when demand response is fully integrated into the retail market. That will happen when a large number of retail electric customers have access to demand-response options. PJM is working with state commissions and other stakeholders to support that goal (*see response to Question 12*). This effort includes collaborative groups such as MADRI, which is working to find ways to increase the deployment of time-of-use meters and to integrate distributed generation and demand response into state retail rate designs.

[83] In the AEP transmission zone, 1353 MW of Demand Resources and Energy Efficiency Resources was offered in the 2012/2013 BRA and 711 MW cleared; in the Dayton transmission zone, 406 MW of Demand Resources and Energy Efficiency Resources was offered in the 2012/2013 BRA and 112 MW cleared.

PJM's behind-the-meter generation (BTMG) rules permit market participants that have Network Integration Transmission Service agreements with PJM to capture benefits associated with the impact of their BTMG in PJM's Markets. PJM's BTMG rules allow such generation to net for the purpose of calculating transmission, capacity, ancillary services, and administrative fee charges. This approach is intended to encourage the use of BTMG during times of scarcity and high prices, thus increasing the opportunity for load to compete in PJM Markets. PJM's BTMG rules apply to BTMG used by end-use customers, municipal electric systems, electric cooperatives, and electric distribution companies to serve load.[84] Generally, the load must be located at the same electrical location as the BTMG, such that no transmission or distribution facilities are utilized to transmit energy from the BTMG to the load.

12. Are the RTOs' policies and practices relating to the treatment of Price Responsive Demand (PRD) consistent with facilitating the development of PRD through dynamic and time-differentiated real time pricing? (PRD is consumer demand that predictably responds to changes in wholesale prices as a result of dynamic or time-differentiated retail rates.)

PJM enthusiastically concurs that significant penetration of PRD will provide substantial system benefits if properly incorporated into the regional market. PJM is working closely with Commissioner Paul Centolella, the Commission's representative on the Organization of PJM States (OPSI), to develop a conceptual framework for facilitating the development of PRD through dynamic and time-differentiated real time pricing.[85] PRD can reduce overall costs by improving existing asset utilization and risk by mitigating extreme price volatility, and will make the market more competitive during peak usage hours by introducing demand elasticity. PRD will provide the predictability of demand requirements and power flows in daily operations as well as rapid response to emergency shortage conditions to preserve short-term system reliability, and has the potential to reduce the planning reserves required to meet Loss of Load Expectation-based planning objectives.

[84] Non-Retail BTMG netting provisions apply to behind the meter generation used by municipal electric systems, electric cooperatives, and EDCs to serve load, provided that, if distribution facilities are used to deliver energy from Non-Retail BTMG to load, then permission to use such distribution facilities has been obtained from the owner, lessee, or operator of such distribution facilities. Non-Retail BTMG netting is subject to a threshold amount.
[85] The conceptual framework for facilitating PRD development includes the development and use of a Price Response Demand Curve, an Operating Reserve Demand Curve, capacity and planning reserves for forecasted firm demand, and non-discriminatory procedures for dumping load in a capacity emergency that recognize the extent to which PRD and non-PRD loads are capacity deficient. While longer term forecasting will need to evolve to reflect the development of PRD as forecasters acquire sufficient data about the behavior of locational PJM price responsive loads, PRD can be reflected in shorter term forecasting with the addition of a locational PRD forecast modifier.

In parallel to, and complementing that effort, PJM worked through its Task Force 719 stakeholder process to address concerns articulated by FERC in Order No. 719[86], as explained in PJM's Order No. 719 compliance filing[87]. FERC observed in Order 719 that RTO tariff provisions "may not produce prices that accurately reflect the value of energy, and by failing to do so, may harm reliability, inhibit demand response, deter entry of demand response and generation resources, and thwart innovation.....[B]y artificially capping prices, price signals need to attract new entry by both supply- and demand-side resources are muted and long-term resource adequacy may be harmed. Without accurate prices that reflect the true value of energy, we cannot expect the optimal integration of demand response into organized markets."[88] PJM's Order 719 compliance filing addresses its desire to implement an Operating Reserve Demand Curve framework for the pricing of energy during periods of operating reserve shortages that will help ensure system reliability and remove barriers to all forms of demand response including PRD.

Currently PJM initiates scarcity pricing only when specific emergency conditions have actually occurred. The approach of a reserve shortage is not signaled in advance of an actual emergency event through increases in energy or reserve prices. Prices just prior to the initiation of a scarcity event under the current scarcity pricing mechanism may actually fall or remain artificially low as Emergency Load Management resources are called and reserves are allowed to fall into shortage. With the initiation of scarcity, the resulting rapid and large step-change increase in prices to signal scarcity to the market may occur too late to allow resources, including demand, to respond efficiently. An Operating Reserve Demand Curve would raise energy and ancillary service prices in a gradual, pre-determined manner consistent with security constrained economic dispatch as reserve levels fall below their target levels. The transparency of these price signals to PRD would thus trigger the appropriate response of reducing load thereby enhancing system reliability. Moreover, an Operating Reserve Demand Curve paradigm enhances market efficiency by allowing the demand-side of the market to set prices based on the marginal willingness to pay for energy and reserves whether through a point on the operating reserve demand curve or through the responses of PRD.

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[86] *In the Matter of Wholesale Competition in Regions with Organized Markets*, Order No. 719, 73 Fed. Reg. 64,100, (October 28, 2008), FERC Stats. & Regs. Paragraph 31,281 (2008).

[87] *PJM Compliance Filing*, Docket No. ER09-1063, April 29, 2009.

[88] *In the Matter of Wholesale Competition in Regions with Organized Electric Markets*, 125 FERC Paragraph 61,071 (October 17, 2008) at 192 -193.

PJM has requested an extension of time from FERC by which to submit its formal scarcity pricing proposal, until April 1, 2010. At this time, none of the alternatives discussed in PJM's Task Force 719 stakeholder process for modifying PJM's current scarcity pricing mechanism to achieve full compliance with the requirements of Order No. 719 has been sufficiently developed. Nevertheless, PJM has advised its stakeholders and FERC that it proposes developing and implementing an Operating Reserve Demand Curve, and stakeholders will be engaged in efforts to further specify its characteristics.[89] PJM has initiated the Scarcity Pricing Working Group to recommend alternative methods for scarcity pricing as well as develop the required implementation details.[90]

13. Are the RTOs' queue and interconnection policies providing value to Ohio's consumers?

PJM's queue and interconnection policies provide value to Ohio's customers by assuring that regional transmission reliability is maintained as facilities are interconnected and reinforcing supply adequacy and competitive markets for PJM's market participants and the customers they serve. As well, PJM's interconnection process provides equal access for generation powered by renewable fuel sources and distributed generation, benefitting Ohio consumers by facilitating state energy policy directives involving the development in Ohio of renewable generating resources, as well as the delivery of renewable resource generated electricity into the State; and encouraging the deployment of distributed generation. Recent steps PJM has taken to improve its queue and interconnection processes will benefit Ohioans by minimizing the number of speculative projects that enter PJM's queues in order to mitigate delay in PJM's processing of more material projects. In turn, this and other improvements to PJM's queue and interconnection process will assist developers in making timely investment decisions.

PJM coordinates the planning process for connecting new generation, analyzes the reliability impact of proposed generating projects and oversees the construction of the facilities required to interconnect new

[89] A reserve demand curve can be constructed in many ways, ranging from penalty factor determinations as developed by ISO New England and the NYISO and suggested by PJM's IMM, to more sophisticated methods based on the value of lost load and deriving the value of expected unserved energy at different reserve levels.

[90] Among the features of PJM's scarcity pricing mechanism that require additional development is an appropriate and transparent revenue offset mechanism with RPM to ensure scarcity revenues collected by RPM resources offset RPM revenues.

generation to the grid. A key component of PJM's RTEP process is the assessment of queued generation interconnection requests and the development of transmission upgrade plans to resolve reliability criteria violations.[91]

PJM's queue-based, 3-study interconnection process offers developers the flexibility to consider and explore business opportunities as power producers in PJM. While a developer can withdraw at any point, the process is structured such that each step imposes its own increasing financial obligations on the developer. The process also establishes milestone responsibilities for the developer, PJM and each affected Transmission Owner (TO).[92]

PJM's Capacity and Energy Markets continue to attract significant volumes of generation interconnection requests, constituting a significant driver of regional transmission expansion needs. Significant increases in the volume of interconnection requests since the beginning of Queue M on February 1, 2004 has driven a proportionate increase in the number of interconnection studies required. These studies ensure the means for delivering the output of interconnected generation. PJM's generator interconnection process continues to ensure that new capacity resources satisfy load serving entity requirements to meet their obligations reliably.

Interconnection requests for generation powered by renewable fuel sources require specific analytical studies unique to their particular characteristics. For example, wind-powered generator requests have clustered in remote areas most suitable to their operating characteristics and economics but with weaker transmission infrastructure. Such an influx of potential generation projects increases system stress in areas already limited by existing operating guide restrictions or special protection systems. Consequently, PJM is increasingly encountering the need for baseline reevaluation involving complex power system stability studies, low-voltage ride-through studies and others. While some renewable resources can operate in a

[91] Interconnection projects may be evaluated as a PJM Capacity Resource or as an Energy-only Resource based on their application for interconnection. PJM's study process for each interconnection request and the required upgrades such studies reveal, ensures the initial deliverability of each request. Thereafter, the PJM annual RTEP cycle encompasses studies that assess transmission expansion upgrades then needed to ensure the ongoing deliverability of all generators within PJM consistent with their requested interconnection rights.

[92] The interconnection process is discussed in detail in PJM Manuals 14A and 14B.

manner similar to the traditional fossil fueled power plants, other renewable energy sources such as wind are recognized as intermittent resources. Their ability to generate power is directly determined by the immediate availability and/or magnitude of their specific "fuel." For example, wind turbines can generate electricity only when wind speed is within a range consistent with the physical specifications of the related turbines. This presents challenges with respect to real-time operational dispatch and specific capacity value. To address the latter issue, PJM has established a set of business rules unique to intermittent resources that provide for the determination of credible capacity values robust enough to represent capacity during the PJM summer peak period. The unique interconnection requirements of intermittent resources, such as wind, continue to be examined through a PJM stakeholder group, the Intermittent Resources Working Group.

PJM's power market has attracted over 277,000 MW of interconnection requests from generation developers – both traditional utility players and non-utility entities. More than 6,500 MW of new generating resources are presently under construction with over 85,000 MW participating actively in PJM's interconnection process. These generation additions enhance system reliability, supply adequacy and diversity, and competitive markets for PJM's market participants and the customers they serve. Proposed generation now includes wind at nearly 40 percent; natural gas at nearly 40 percent; coal at 6 percent and nuclear at almost 7 percent. Overall, a generation portfolio of diverse fuel sources reduces the risk to system reliability from the availability of individual fuels, the transportation of individual fuels, and the impact on dispatch from fuel price variations and consequent generation loading patterns.

The magnitude of interconnection requests – over 59,000 MW demonstrates the viability of renewable technologies as part of PJM's fuel mix. The PJM Interconnection process offers a structure that assures consistent opportunity for development across fuel types, while providing the flexibility to adapt to specific technical realities and market challenges. The non-discriminatory nature of PJM's RTEP process has permitted significant growth in renewables in recent years. Interconnection request totals through January 31, 2009 include 55,000 MW of wind generation, 600 MW of methane, 500 MW of biomass and 2,700 MW of hydro.[93]

[93] Section 8 of the 2008 PJM Regional Transmission Expansion Plan provides information on a state-specific basis regarding generating resource interconnection requests as well as interconnection requests for generation powered by renewable fuel sources.

PJM's queue and interconnection policies reinforce Ohio's energy policy by accommodating the interconnection of small generating resources and distributed generation to participate in PJM's markets. PJM's queue and interconnection policies facilitate the implementation of Ohio's energy policy by providing expedited procedures for the interconnection of new resources of less than 20 MW or increases of less than 20 MW to existing generation. Expedited procedures are defined for three categories of small resource additions: permanent capacity resource additions, permanent energy-only resource additions, and temporary energy-only resource additions. Further, requests for the interconnection of new resources of 2 MW or less may be expedited through the use of pre-certified generation equipment and systems that meet IEEE Standard 1547 technical requirements.[94] PJM's policies also accommodate the participation of distributed generation in PJM's markets. Distributed generation can apply to take part in wholesale sales of energy and/or capacity into the PJM markets by executing a PJM Wholesale Market Participation Agreement to specify coordination terms and conditions. PJM accepts distributed generation into the interconnection queue process so that PJM may assess the impact of its potential wholesale power transactions on the PJM bulk power system.

PJM has recently taken significant steps to improve its interconnection request process. Throughout 2008, PJM actively engaged stakeholders in discussion of interconnection process enhancements to address the backlog of projects in the queues with pending interconnection requests yet to be studied. Attention focused on means to ensure that projects embarking on the PJM study process are ready to commit resources to project development and also on methods to facilitate the processing of projects once they enter the queue. On August 19, 2008, FERC accepted certain of PJM revisions for filing; other revisions were implemented via incorporation in PJM's Manuals.[95] PJM continues to improve its interconnection request process, having recently proposed tariff changes at FERC to reduce deposit fees for facilities studies for small generators, ensure collection of past due invoices, and permit parties to defer providing security under an Interconnection Service Agreement for up to four months.[96]

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[94] Procedures for requests under these two scenarios are detailed in PJM Manual 14A, "PJM Generation and Transmission Interconnection Process."

[95] Table 9.3 of the PJM 2008 Regional Transmission Expansion Plan provides a summary of the various queue and interconnection process improvements incorporated in PJM's OATT or its Manuals.

[96] *PJM Interconnection L.L.C.,* Case Nos. ER09-977 and ER09-978, April 8, 2009.

14. Is the resolution of seams issues being thoroughly addressed and resolved by the RTOs operating in Ohio?

Some entities have raised unsubstantiated concerns over the sufficiency of coordination between MISO's and PJM's wholesale markets, which together comprise the wholesale market area in Ohio. Congestion in the wholesale markets serving Ohio is relatively unconstrained, resulting in a broad diversity of supply alternatives for Ohio. PJM and MISO have implemented joint congestion management procedures in real-time operations which further facilitate interregional energy transactions. While the PJM and MISO markets are not jointly dispatched, PJM and MISO have implement joint congesting management protocols in real-time operations that have significantly improved the level of real-time coordination while mitigating dependence on transmission loading relief mechanisms that severely restricted transactions and reliability alternatives.

In 2007, FERC affirmed that, through their Joint Operating Agreement (Agreement), PJM and MISO have achieved levels of coordination unequalled by other RTOs.[97] Pursuant to the Agreement, PJM and MISO coordinate their re-dispatch on a least-cost basis, with financial settlements through which each RTO is compensated for the re-dispatch it provides to the other RTO. FERC dismissed the complainant's concern over differences between shadow prices and proxy bus prices at the MISO-PJM border, pointing out that FTRs may offset such costs, and that PJM's implementation of marginal losses and identical treatment by MISO and PJM of dynamically scheduled generation units will reduce the level of price separation observed at the RTOs' border. FERC also noted that differences in shadow prices do not necessarily signify that the cost of relieving a constraint can be reduced by undertaking more re-dispatch, since shadow prices are based on the cost at which re-dispatch was last provided. PJM submits that differences in shadow prices may be due to influences external to PJM and MISO, or may reflect that one RTO may not have generation available to re-dispatch to cost-effectively manage congestion.

In rejecting the complaint, FERC concluded that there are no major barriers to inter-RTO trades, as evidenced by intensive hourly cross-border activity, and acknowledged that the MMUs for both PJM and MISO analyzed price convergence between the RTOs and concluded that while some improvement is warranted, the JOA was operating well, with hourly absolute differences in border prices lower in 2006 than

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[97] EL06-97-001, *Order Dismissing Wisconsin Public Service Corporation Complaint and Terminating Reporting Requirements*, 118 FERC Paragraph 61,089, February 8, 2007, and *Order Denying Rehearing of February 8, 2007 Order Dismissing Wisconsin Public Service Corporation Complaint*, 120 FERC Paragraph 61,269, September 24, 2007.

in 2005. FERC also noted the PJM IMM's finding that the simple average interface price difference suggests that competitive forces prevent price differentials from persisting. PJM has evaluated average hourly PJM-MISO interface price differences [98] and converted them into annual averages. The annual averages for 2005 (April through December), 2006, 2007, 2008 and 2009 (Through March) are -\$3.3, \$0.3, -\$1.3, -\$1.3 and -\$0.5.

The PJM-MISO Joint Operating Agreement explicitly requires ongoing analysis of Joint and Common Market features which have the potential to improve seams coordination. PJM and MISO continue to evaluate what individual elements of a Joint and Common Market are feasible and beneficial to implement.[99] As well, PJM and MISO regularly coordinate to resolve issues raised by differences in their protocols that impact transmission system transactions.[100]

15. Does the RTOs' treatment of financial-only market participants (or virtual traders) provide value to Ohio consumers

Ohio consumers benefit significantly from the financial-only traders participating in PJM's markets. Although the current economic climate has placed on onus on financial trading in general, speculative energy market traders add real value to the market by facilitating price convergence in the day-ahead and real-time markets, and at no real cost to other participants. Indeed, there are major differences and few similarities between the role played by energy market financial market participants, *i.e.* virtual traders, and the financial traders who brought the U.S. and indeed the world economy to the precipice of calamity.

[98] The analysis considered PJM's proxy for MISO minus MISO's proxy for PJM, which can be positive or negative for each hour. A positive number indicates PJM's proxy for MISO is higher than MISO's proxy for PJM for that hour.

[99] Bimonthly JCM Status Reports are posted on the MISO-PJM Joint and Common Market Website, accessible at http://www.miso-pjm.com. The March 2009 JCM Status Report provides information on previous and current JCM initiatives. Current initiatives in the implementation phase include Alignment of PJM Operating Reserves and MISO Revenue Sufficiency Guarantee intended to reduce hurdle rate; Common Ramp Portal to improve operational consistency; Alignment of Agreements and Practices regarding black start and restoration; and Cross Border Cost Sharing of Expansions to facilitate joint expansion planning and common deliverability studies. Current initiatives "on hold" and subject to additional analysis include Cross Border FTRs, Shared Regulation Market, Coordinated OASIS, Netting in the IDC, and Dynamic Dispatchable Transactions and Schedules.

[100] For example, PJM and MISO jointly filed a Capacity Portability Agreement with FERC to satisfy Buckeye Power's obligations under the MISO Tariff, as may be applicable to Buckeye's load located within the boundaries of MISO's Balancing Authority Area, which load is served under the terms and conditions set forth in PJM's Tariff. The Agreement is a means by which Buckeye Power, as a load serving entity with load located in MISO will be permitted to utilize or make "portable" the capacity acquired on Buckeye Power's behalf in PJM's RPM markets through May 31, 2013.

Nodal (point) financial contracts obligate the buyer to the revenue, positive or negative, associated with the difference between the forward and real-time energy market prices at a pricing node. They are pure financial contracts that need not be associated with a physical asset. They can be used with physical assets, but also can be used purely for speculation. The focus of this inquiry is on the speculative traders, and, our response addresses their role and impact in the energy market.

There are two kinds of nodal financial contracts, also known as virtual trades: increment and decrement. Increment bids are analogous to generation in the forward market in that they add to the forward supply curve, while decrement bids look like load and add to demand.

The structure of the energy market two-settlement system is such that energy market traders make a profit only if they add value to the overall market and increase overall market efficiency by improving price convergence. For example, if a pricing node is overvalued, i.e. priced higher, in the forward energy market relative to real-time, participants who buy actual energy at that location in the forward market will pay and sellers will receive supra rents. However, financial traders that bid appropriately can move the forward price closer to real-time, moving forward and real-time prices toward what is known as market convergence—when forward and real-time prices align—improving overall market efficiency and these traders will receive a portion of the improvement in efficiency as payment for services rendered. Meanwhile, physical buyers and sellers transact energy at the improved price.

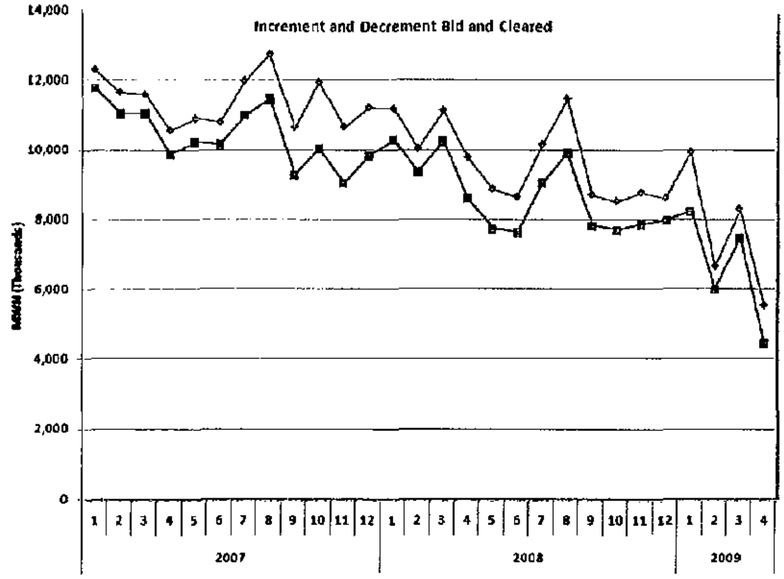
Conversely, energy traders lose money when they do not improve price convergence. In the same example where a pricing node is overvalued in the forward market, financial traders whose trading activity moves the forward price away from the real-time price and decrease market convergence will lose money.

A sustainable, robust forward energy market cannot operate efficiently without financial contracts and traders. In the previous example there would be no way to correct the elevated forward price relative to real-time and achieve price convergence without financials contracts, and market efficiency would be less than optimal. It is an undeniable precept that the implementation of a two-settlement system requires financial contracts and traders.

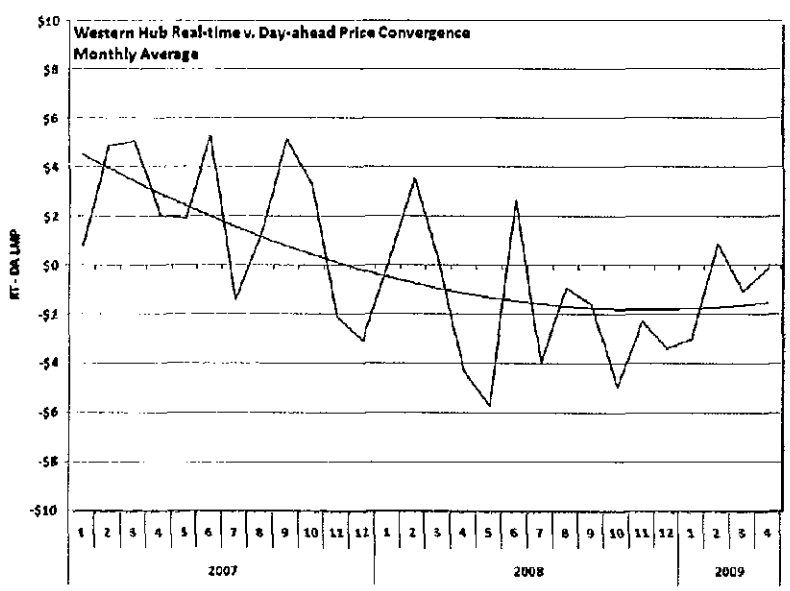
There are self-correcting phenomena that preclude cherry-picking and ravaging the market by energy traders. First, the market rewards financial contracts that improve efficiency and penalizes those that do not, so energy traders only make money when they provide price convergence and lose money when they do not. Rational behavior dictates that a money-losing trading strategy will not be continued for long or financial ruin of the trading enterprise will result, so financial trades should tend in aggregate to improve market efficiency. Second, as stated the market only rewards financial trades that improve efficiency, but as market convergence improves the rewards of financial trades diminish. Financial bids get paid based on the difference between forward and real-time prices, so trades that provide excellent market convergence—that is move the forward price precisely to or close to the real-time price—receive little or nothing in return, and all of the benefits of the improvement in market efficiency accrue to other participants. Another self-correcting phenomenon is that because of the excellent transparency of the energy market, when price divergence exists, numerous traders are motivated to bid that location. This makes it harder for individual traders to be successful, yet their actions in aggregate will work toward eliminating the price divergence. Finally, energy market financial traders are required to possess adequate credit, unlike some derivative markets, greatly reducing the chance of defaults.

As volatile as natural gas and electricity prices were during the first half of 2008, the capital markets were equally volatile during the second half of 2008. As financial institutions experienced growing distress, the energy markets were affected in two ways. First, trading of financial energy products decreased, while financial institutions and energy marketers took a smaller role in energy markets. Second, energy market participants experienced reduced access to and a higher cost of capital, resulting in reductions in capital expenditure budgets.

As the exhibit on the following page illustrates, by August 2008, the volume of financial electricity product trading at the PJM Western Hub started to drop relative to the previous year. This occurred after dramatic increases from January through July. This pattern held in most of the largest volume trading hubs. For instance, in the largest ICE trading hub, PJM West, Q4 2008 trading was down 39% relative to Q4 2007. Trading at both SP-15, the second largest hub, and NEPOOL, the fourth largest hub, was down just over 10% after earlier gains. The volume of Q4 2008 trading at several other hubs, like Mid-Columbia, the third largest hub, and Cinergy, was flat relative to Q4 2007, even though trading during the first part of 2008 was up substantially relative to 2007.



The following exhibit displays PJM Western Hub average monthly price convergence, i.e. the difference between real-time and day-ahead prices. A trend line is superimposed on the price lot to illustrate the convergence of the prices toward zero. The shape of the curve is very similar to that displayed in the former exhibit, illustrating how increment and decrement volume drops off as price convergence approaches zero in 2009. Interpreted together, these two exhibits reveal that as the market matures and price convergence improves, the energy market "self-corrects": as price differences decrease, the return on these financial instruments is reduced, making them less attractive for speculation.



16. Are the RTOs' administrative expenses and corresponding assessments to member companies reasonable and resulting in value to Ohio's customers?

Considering the wide array of benefits provided by PJM and documented above, Ohio customers receive great value for their costs incurred for PJM's administrative expenses, and the corresponding assessments to member companies. Assuming PJM's annual expense budget is approximately $200 million, then PJM's value proposition of $1.6 billion to $2.3 billion annually represents at least an 8:1 value-to-cost proposition.

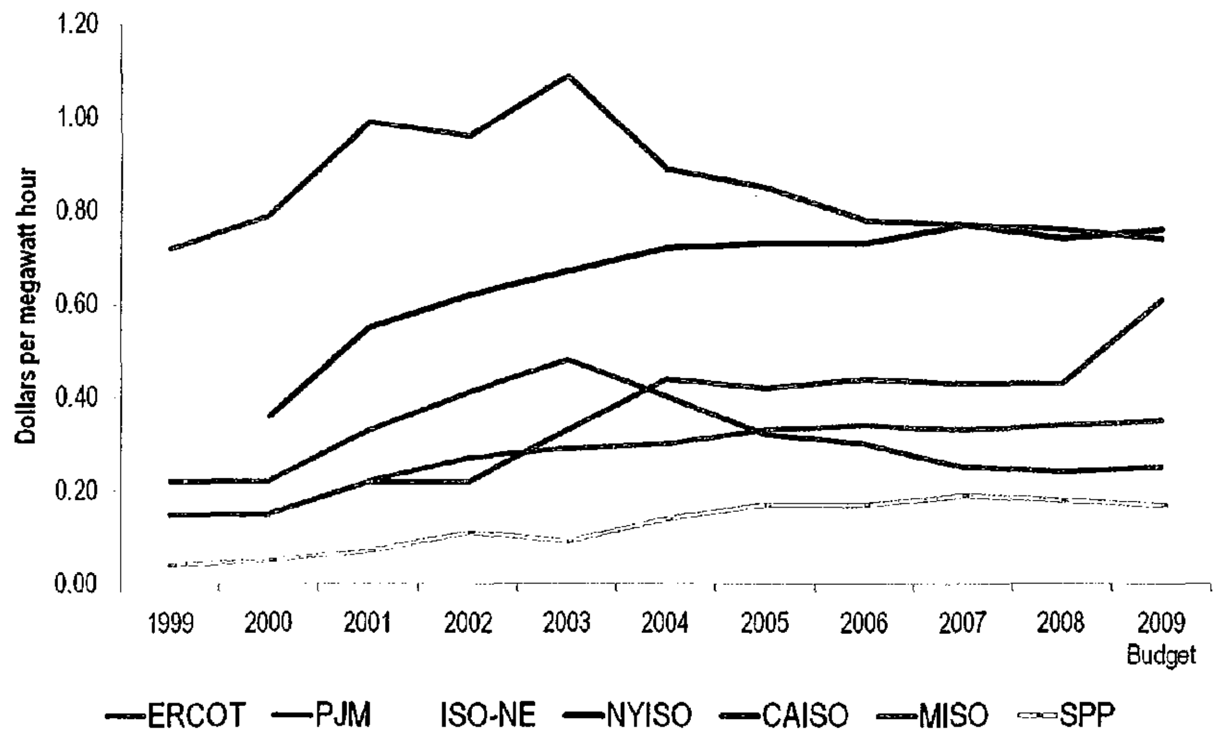
PJM's administrative expenses are recovered through a FERC-approved "stated rate" tariff structure[101]. PJM proposed a stated rate tariff structure to provide members with greater pricing certainty and to impose fiscal discipline on PJM and its management. PJM implemented its stated rate structure for recovery of PJM's administrative costs on June 1, 2006. Under this tariff design, PJM and its stakeholders established fixed rates to be charged to its members based on their transaction activity. PJM's stated rates charge its members administrative costs based on their transaction volumes as described in the exhibit on the following page.

[101] PJM is the only RTO with a stated rate that sets a ceiling on RTO spending before a rate case would be required.

Stated Rate Service Category	Stated Rate Billing Determinant	Portion of PJM Costs Charged to Users of Service Category
Control Area Administration Service – uactivities of PJM associated with preserving the reliability of the PJM region and administering point-to-point and network integration transmission service	Megawatt Hour of Load Served	58%
Financial Transmission Rights (FTR) Administrative Service – activities of PJM associated with administering FTRs including FTR bilateral trading, administration of FTR auctions, support of PJM's on-line eFTR tool, and related analyses.	Megawatt Hours of FTRs Bid plus Held	5%
Market Support – activities of PJM associated with supporting the operation of the PJM's day-ahead and real-time energy markets	Megawatt Hour of Energy Sold plus Megawatt Hour of Load Served plus Megawatt Hour of Virtual Bids	30%
Regulation and Frequency Response Administration – activities of PJM associated with administering the provision of regulation and frequency response service	Megawatt Hours of Regulation Service Purchased plus Sold	2%
Capacity Resource and Obligation Management Service – activities of PJM associated with ensuring that customers have sufficient generating capacity to meet their installed capacity obligations, processing network integration transmission service requests, and administering the forward capacity market in the PJM region.	Megawatt Day of Capacity Resources Provided plus Capacity Obligation	5%

For ease of comparison and discussion, the administrative costs of Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs) are often discussed in terms of a composite rate. Such composite rate is calculated as the RTO's annual administrative costs divided by the aggregate megawatt hours of load served by the RTO in the same twelve-month period.

The exhibit below illustrates that PJM's administrative costs exclusive of FERC fees and expressed as a composite rate are lower than every other RTO with the exception of SPP.[102]



The stated rates in PJM's tariff were established as declining rates from 33 cents per megawatt hour (MWh) of load served in 2006 decreasing to 30 cents per MWh for 2011 and forward to require PJM to continue its cost management efforts.

Any stated rate revenues in excess of PJM's actual expenses are refundable to PJM's members on a one-quarter lag. Refunds to PJM's Members under the stated rate structure were $6.5 million, $52 million, and $63 million related to 2006, 2007 and 2008 activity, respectively. These amounts represent between 3 and 26 percent of the stated rate revenues charged to PJM's Members in each of those years.

[102] SPP's lower composite rate reflects its lower market administration costs. At the present time the only market SPP administers is its Real Time Energy Imbalance Service Market, although it developing a Day-Ahead Market and an Ancillary Services Market to be implemented in 2012.

The benefits of PJM's stated rates include: 1) increased cost efficiency and productivity focus for PJM to ensure its expenses do not exceed the fixed stated rates; 2) onthly and multi-year rate predictability for PJM's members compared with formula rates; and 3) Greater financial transparency with PJM's members.

PJM recovers the costs of its core reliability functions through the Control Area Services service category. PJM has been performing these system operations and planning functions since well before the initiation of wholesale, competitive markets. In fact, the inflation-adjusted pre-markets PJM composite rate would have been 14 cents per MWh in 2008.[103] The actual costs, net of refunds, charged to PJM's members under the Control Area Services service category were 13 cents per MWh in 2008.

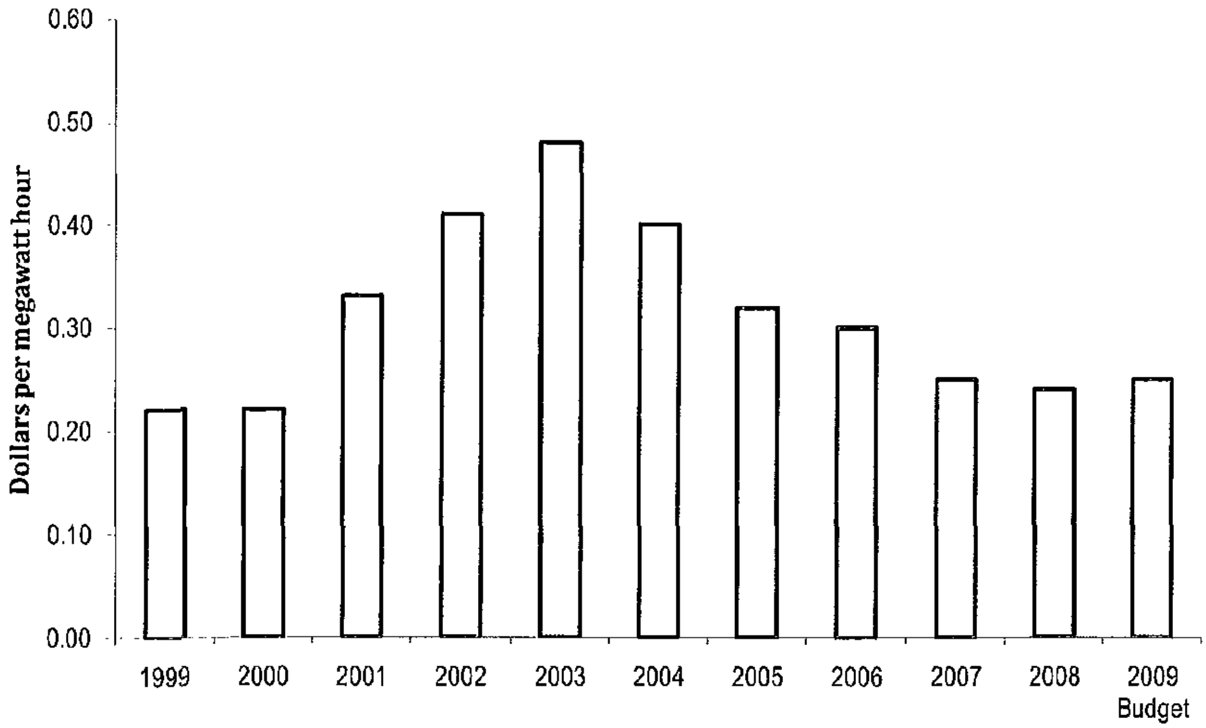
The transition to stated rates is one component of PJM's focus on providing cost-effective services. Other cost controlling measures have been instituted by PJM, too. For example, in fall 2003, PJM's CEO initiated a cross-divisional Productivity Enhancement Task Force (PETF). The PETF was charged with developing a five-year plan whereby PJM would generate cost efficiencies in addition to those achieved through the 2002 – 2005 market integrations. Specifically, the PETF was tasked with identifying recurring cost savings in addition to those achieved through the anticipated market integrations such that PJM's 2008 and forward composite rate per MWh would 31 cents or less.

Through proactive examination of PJM's processes, culture, and business practices the task force identified opportunities for improvement in costs and efficiency. This process was designed to provide for prudent growth while incorporating these efficiencies as well as cost savings. Ultimately, actions initiated by the task force delivered increased value to PJM's membership through lower costs, increased satisfaction, and continued reliable operations.

As noted in PJM's 2007 Annual Report, the PETF initiative resulted in recurring cost savings of $34 million or approximately 4.55 cents per MWh of load. Further, PJM's actual 2008 administrative expense rate was $0.26 per MWh of load. The primary areas for which cost efficiencies were identified and realized were information technology systems rationalization, vendor consolidation and process improvements.

[103] Inflation factor for 1996 to 2008 per www.inflationdata.com.

As the following exhibit illustrates, PJM's actual composite expense rate per megawatt hour of load, net of refunds, reached a peak of 48 cents in 2003 before declining to 26 cents in 2008. PJM's region expanded significantly from 2002 through 2005. The incremental transaction volumes from these additional transmission zones and members resulted in significant administrative economies of scale benefits for all PJM members.

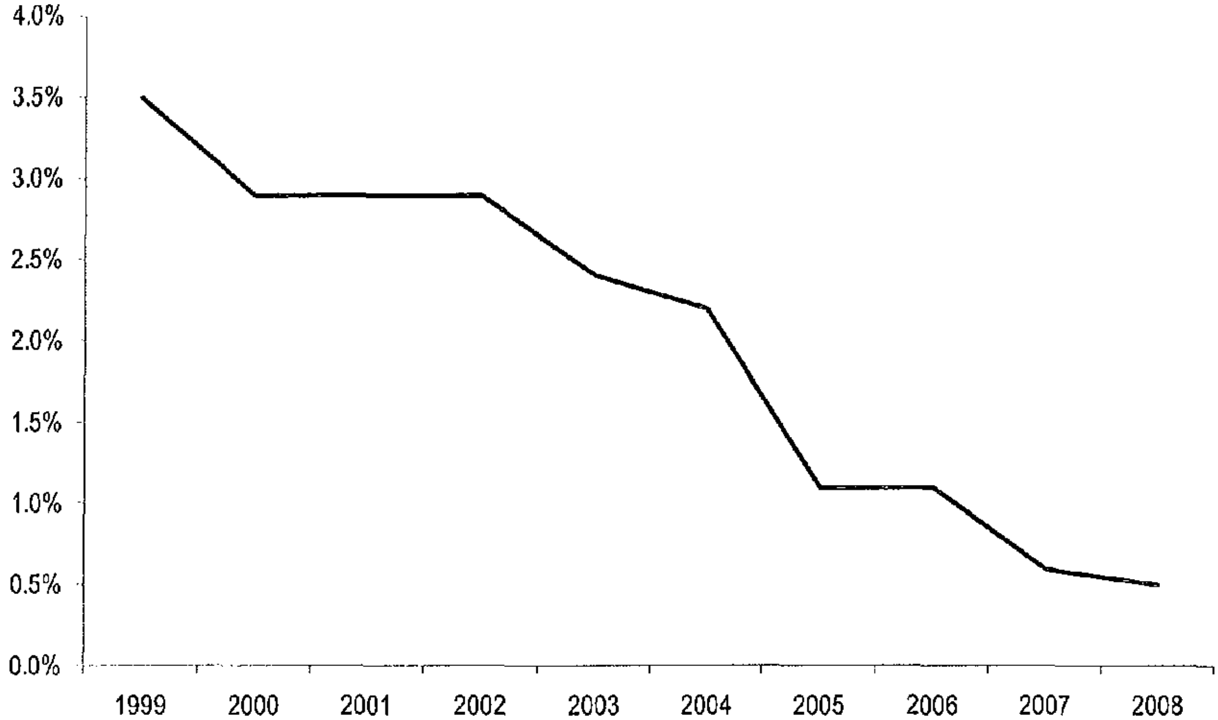


Since PJM's inception and to date, PJM and its members have agreed that PJM's operating expenses should be recovered in administrative rates on a current, instead of deferred, basis. This approach has allowed PJM to minimize its borrowing requirements which reached a peak of $143 million in 2003 and were $20 million at the end of 2008. This ability to manage PJM's operations at low debt levels has precluded PJM from ever pursuing tariff authority to charge any exit fees to a member that chooses to withdraw from PJM.

PJM has an extensive Financial Review, Reporting and Communications Protocol with the Finance Committee representatives elected by PJM's members. This protocol ensures financial transparency with PJM's members. A key component of this protocol is the Finance Committee's letter to the PJM Board of Managers with recommendations on the annual expense and capital budgets proposed by PJM management. Since the implementation of stated rates, the Finance Committee has unanimously recommended each year's proposed budgets. Further, the Finance Committee has provided feedback to the PJM Board of Managers such as the following:

> "PJM should be congratulated for its management of the corporation's expenses."
>
> "The Sector-Elected representatives of the PJM Finance Committee commend the diligence of PJM's management for their diligence in pursuing and sustaining efforts to reduce expenses."
>
> "The Finance Committee is pleased with the functioning of the protocols and the collaborative efforts of PJM Management, the Board members, and the Sector-Elected Finance Committee representatives. This includes both the organization of the annual Finance Committee plan, the materials and presentation of information, and the additional responses to supplemental requests and independent financial and PJM's annual SAS 70 Type 2 audits. Overall, operation and coordination between the Finance Committee and PJM Management appear to have significantly enhanced the understanding and effectiveness of the Finance Committee and its ability to provide substantive and meaningful recommendations to the Board and PJM stakeholders."

PJM's administrative costs are a very small and decreasing portion of PJM's members' wholesale transaction dollars. The exhibit on the following page shows the portion of its members' wholesale electricity bills from PJM that represent PJM's administrative costs.



A typical Ohio household uses 750 kwh of electricity per month. PJM's 2008 administrative charge net of refunds for a typical Ohio household is 19.5 cents per month, a reasonable price to pay for the array of benefits PJM provides. In the future, as PJM recovers its multi-year investment in a dual control center with a new Energy Management System targeted for completion in 2010, Ohio household costs will increase, but will remain less than 25 cents per month, assuming a consistent level of refunds to members.

PJM appreciates the opportunity to submit comments regarding the value of continued participation of Ohio electric utilities in RTOs, and looks forward to responding to the comments of other stakeholders in order to fully inform the Commission of the benefits delivered by PJM.