APPENDIX D - INTERCHANGE TRANSACTIONS

In competitive wholesale power markets, price signals guide purchase and sales decisions. If neighboring wholesale power markets incorporate security-constrained nodal pricing and are designed and managed well, the interface pricing points allow economic signals to guide efficient import and export decisions. When a competitive market shares a boundary with an area reliant on bilateral contracts and associated contract paths to manage transactions, however, the independent system operator (ISO) or regional transmission organization (RTO) needs to define its interface pricing points so that imports and exports, especially under conditions of congestion, face price signals that are consistent with the underlying reality of generation and transmission resources.

PJM has an established process for developing and implementing interface prices. PJM increased the sophistication of that process in 2002 by addressing the causes of loop flow. PJM further developed the application of interface pricing for the integration of the Commonwealth Edison Company (ComEd) Control Area.[1,2] Located in Northern Illinois, the ComEd Control Area was linked to the rest of the PJM through a Pathway. On October 1, 2004, with the Phase 3 integration of the American Electric Power Company (AEP) and The Dayton Power & Light Company (DAY) Control Zones, the Pathway was internalized.[3]

PJM's evolution during 2004 required the establishment of new interfaces and interface pricing points during Phase 2, some of which were eliminated during Phase 3.

The integrations of Phases 2 and 3 created new boundaries including boundaries with the Midwest Independent Transmission System Operator, Inc. (Midwest ISO). Since the Midwest ISO is not yet operating a competitive market with security-constrained redispatch rights, congestion is currently managed through coordinated flowgates under a joint operating agreement between PJM and the Midwest ISO.

Historical Development of Interface Pricing

On July 19, 2002, PJM notified market participants that pricing for transactions scheduled at the PJM/ Dominion Virginia Power (VAP)[4] interface, but delivered at the PJM/AEP interface, would be corrected, effective at 1500 hours Eastern Prevailing Time (EPT).[5] PJM had observed significant and growing differentials between scheduled and actual flows before it issued its pricing notice. The pricing notice provided that import transactions scheduled into PJM at the PJM/VAP interface would be paid the price at the PJM/AEP interface if those transactions originate to the west of PJM, regardless of artificial contract paths constructed to avoid the required pricing. Instead, pricing would be based on the appropriate flow analysis under Section 3.3.1(d) of Schedule 1 of the Operating Agreement.[6]

1 Control zones and control areas are geographic areas that customarily bear the name of a large utility service provider working within their boundaries. The nomenclature applies to the geographic area, not to any single company.
2 Control areas external to PJM are referred to as control areas not control zones. For example, the FirstEnergy control area is not referred to as the FirstEnergy control zone.
3 A description of the interfaces and interface pricing points as they evolved during 2004 can be found in Section 3, "Interchange Transactions."
4 Interfaces are named after adjacent control areas, geographic areas that customarily bear the name of a large utility service provider working within their boundaries. The nomenclature applies to the geographic area, not to any single company.
5 See PJM Marketing Monitoring Unit, "Interface Pricing Policy," as reported to the FERC (August 12, 2002) < http://www.pjm.com/markets/market-monitor/downloads/mmu-reports/ 200208-report-ferc1.pdf > (365 KB).
6 See PJM, "Operating Agreement" (January 25, 2005), Section 3.3.1(d) < http://www.pjm.com/documents/downloads/agreements/oa.pdf > (613 KB).

Historically, PJM had paid external transactions under the assumption that transactions scheduled from or through an adjacent control area were using a direct contract path from that control area to the interface between it and PJM. Therefore, PJM paid external transactions based on scheduled flows to interfaces. The locational marginal price (LMP) at a PJM interface did not assume that transactions were scheduled based on the purchase of contract path transmission service inconsistent with actual transaction flow.

To reflect the actual flow of transactions associated with the PJM/AEP and PJM/VAP interfaces, PJM announced the introduction of the AEPVPIMP and AEPVPEXP interface pricing points in February 2003. Effective March 1, 2003, PJM implemented system changes allowing it to price all transactions that source (have origins) in PJM and sink (have destinations) in one of the relevant defined control areas, at the PJM/AEPVPEXP interface price and all transactions that sink in PJM and source in one of the defined control areas, at the PJM/AEPVPIMP interface price.[7]

PJM Interface Pricing Point Definition – General Methodology[8]

PJM establishes prices for transactions with external control areas by assigning interface pricing points to external control areas. The interface pricing points are designed to reflect the way a transaction from or to an external area actually impacts PJM electrically. External control areas are either adjacent to PJM or not adjacent to PJM.

Transactions between PJM and external control areas need to be priced at the PJM border. A set of external pricing points is used to create such interface prices. The challenge is to create an interface price, composed of external pricing points, that accurately represents flows between PJM and an external control area and therefore to create price signals that embody the underlying economic fundamentals. Transactions between adjacent control areas and PJM flow on one or more physical tie lines that together constitute the interface between the two control areas.

Each adjacent control area either has a separate interface pricing point or, if distribution factor analysis shows that identified adjacent control areas have similar electrical effects on the tie lines connecting them to PJM, multiple adjacent control areas can use a common interface price definition. Thus an interface price definition may include external pricing points from one adjacent control area or a combination of adjacent control areas. An abbreviation of the adjacent control areas is used to create names for the interface pricing points. For example, the MidAmerican Energy Company (MEC) is adjacent to the Northern Illinois (NI) control area (now termed the ComEd Control Zone). The two acronyms, MEC and NI, were combined to create the MECNI name for the interface pricing point between MEC and NI.

7 See PJM Market Monitoring Unit, "Interface Pricing Policy" as reported to the FERC (February 28, 2003) < http://www.pjm.com/markets/market-monitor/downloads/mmu-reports/20030301-interface-pricing.pdf > (654 KB).
8 The following discussion of the PJM methodology for defining interface pricing points relies on the PJM analysis and associated white papers developed in conjunction with the 2004 integrations. The white papers are available through the PJM Web site. See generally PJM, "AEP & DP&L Transmission and Market Integration White Paper, Version 1.4" (September 24, 2004) < http://www.pjm.com/markets/market-integration/downloads/documentation/20040924-v67-aep-dpl-transmission-market-whitepaper-v14.pdf > (890 KB). See also PJM, "Draft ComEd Transmission and Market Integration White Paper, Version 2.3" (April 15, 2004) < http://www.pjm.com/markets/market-integration/downloads/ documentation/comed-transmission -market-implement.pdf> (12.6 MB).

As an example, the PJM analysis for the ComEd integration showed that transactions from specific adjacent control areas had very similar electrical effects on PJM and were, therefore, given the same interface price definition. For example, MEC and Alliant Energy Corporation West (ALTW) are adjacent control areas with similar electrical effects on tie lines connecting them to PJM. As a result, the interface price is the same for both control areas and consists of a combination of external pricing points from both the adjacent control areas.

As another example, the PJM analysis for the AEP and DAY Control Zone integrations showed a number of adjacent control areas with very similar effects on tie lines connecting them to PJM. As a result, single interface pricing points were created to define groups of adjacent control areas. As an example, a group of control areas with similar electrical effects on PJM was determined to include Central Illinois Light Company (CILCO), Illinois Power Company (IP), Indianapolis Power & Light Company (IPL), Ameren, Cinergy Corporation (CIN), East Kentucky Power Cooperative, Inc. (EKPC), LG&E Energy, L.L.C. (LGEE) and Tennessee Valley Authority (TVA). The Southwest pricing point was defined as the single interface price used to price transactions to or from this group of adjacent control areas.

Transactions from external, non-adjacent control areas are also priced at interface prices. PJM, in its AEP and DAY transition white paper, describes how standard power flow analysis tools are used to simulate transactions with external, non-adjacent control areas to obtain distribution factor data. The distribution factor data are analyzed to determine through which adjacent control area the majority of power from the external, non-adjacent control area flows. By calculating the correlation coefficient between the external, non-adjacent control area distribution factor and the distribution factor for each of the adjacent control areas, PJM determines the association of an external control area with one of the adjacent control areas and assigns a corresponding interface price.

A more complex situation arises when a transaction from an external, non-adjacent control area results in similar flows on multiple interfaces with different interface price definitions. In that case, an additional interface price definition may be required to reflect the impact of transactions from the external, non-adjacent control area on multiple interface pricing points defined with adjacent control areas. As an example, flows between the Ontario IESO and PJM tend to be split between adjacent control areas, primarily the New York Independent System Operator (NYIS) and the FirstEnergy Corp. (FE), each of which has a different interface price. Neither interface price was separately appropriate for transactions with the Ontario IEOS. So PJM created the Ontario IESO interface price to include both interface prices so as to appropriately reflect the price for transactions with the Ontario IESO.

Phase 2 Integration of the ComEd Control Area[9]

PJM was comprised of two separate control areas during Phase 2: the PJM Control Area, consisting of the Mid-Atlantic Region and the Allegheny Power Company (AP) Control Zone; and the ComEd Control Area located in Northern Illinois. The two control areas were geographically separate.

The integration of ComEd required the addition of new interface pricing points. Since energy flows from external control areas had different impacts on the two noncontiguous PJM Control Areas,

9 See generally PJM, "Draft ComEd Transmission and Market Integration White Paper, Version 2.3" (April 15, 2004) < http://www.pjm.com/markets/market-integration/downloads/ documentation/comed-transmission-market-implement.pdf> (12.6 MB).

each external control area mapped to one interface pricing point with respect to the ComEd Control Area and to a separate interface pricing point with respect to the PJM Control Area. For example, because an import from AEP impacted each control area differently, there was one interface pricing point for an AEP import into Northern Illinois (AEPNI) and another interface pricing point for an AEP import to PJM (AEPVPIMP). Several additional pricing point illustrations are presented in the PJM white paper on the ComEd integration.[10]

The use of interface pricing points allows two energy transactions with identical physical flows or generation control area (GCA) and load control area (LCA) pairs (GCA is the control area where the generator is located and LCA is the control area where the load is located), to receive the same price regardless of contract path. An import to PJM from FE before the integration of ComEd offers a good example. This import would have received the same pricing point, FE, whether it was scheduled as FE to AEP to PJM or FE to PJM. The same logic can be extended to the period during which ComEd was being integrated, but remained its own, stand alone, control area. This is important because a transaction could be constructed in such a way that a control area could be circumvented even though an electrical impact would still be experienced there. A transaction could be constructed where flows through the control area would not be indicated in its transmission path. For example, if an energy transaction originating in MEC (located west of NI) were destined for the PJM Control Area, the transmission path could be constructed several ways. One way would indicate flow through ComEd and another would not; yet both would be expected to receive the same pricing. The former might have the path MEC to NI to AEP to PJM, but the latter might have the path MEC to IP to AEP to PJM.

In this example, the noncircumventing import into the PJM Control Area comes from the MEC control area. It uses the path MEC to NI to AEP to PJM and would have two pricing points assigned to the wheel through Northern Illinois, one to the import and another to the export. The first part of the transaction is the import at the MECNI interface and it receives a credit equal to the MECNI price. The second part of the transaction is the export at AEPNI and it receives a charge equal to the AEPNI price. Then the flow is into PJM at AEPVP and it is credited the AEPVPIMP price. This yields a final pricing of [(MECNI-AEPNI)+AEPVPIMP]. The circumventing import with the path MEC to IP to AEP to PJM would simply be assigned the posted pricing point of MECPJMIMP. MECPJMIMP is defined as [(MECNI-AEPNI)+AEPVPIMP]. In both cases the final pricing is the same.[11, 12]

10 See generally PJM, "Draft ComEd Transmission and Market Integration White Paper, Version 2.3" (April 15, 2004), pp. 51-53 < http://www.pjm.com/markets/market-integration/ downloads/documentation/comed-transmission-market-implement.pdf> (12.6 MB).
11 See generally PJM, "Draft ComEd Transmission and Market Integration White Paper, Version 2.3" (April 15, 2004), pp. 8-9 < http://www.pjm.com/markets/market-integration/ downloads/documentation/comed-transmission-market-implement.pdf> (12.6 MB).
12 For simplification, these examples assume no line losses. The impact of line losses in this type of example is discussed in the PJM white paper on the ComEd integration. It explains that implementation of marginal losses was necessary given the geography of the two control areas.

Phase 2 Interface Pricing Point Definitions[13]

During Phase 2, PJM transactions occurred at 23 defined pricing points (Table D-1).

Table D-1 - ComEd interface pricing point definitions

Pricing Point	Definition
AEPNI	Price at the AEP interface with the ComEd Control Area in NI
AEPVPEXP	Export (EXP) price at the AEP/VAP interface with the PJM Control Area
AEPVPIMP	Import price at the AEP/VAP interface with the PJM Control Area
ALTE	Price at the Alliant Energy Corporation eastern (ALTE) interface with the ComEd Control Area in NI, defined as the same as the price at the Wisconsin Energy Corporation (WEC) interface with the ComEd Control Area
ALTW	Price at the Alliant Energy Corporation western (ALTW) interface with the ComEd Control Area in NI, defined as the same as the price at the MEC interface with the ComEd Control Area
AMRN	Price at the Ameren Corporation (AMRN) interface with the ComEd Control Area in NI, defined as the same as the price at the IP interface with the ComEd Control Area
CILC	Price at the Central Illinois Light Company (CILC) interface with the ComEd Control Area in NI, defined as the same as the price at the IP interface with the ComEd Control Area
DLCO	Price at the Duquesne Light Company (DLCO or DQE) interface with the PJM Control Area
FE	Price at the FirstEnergy Corp. (FE) interface with the PJM Control Area
Ontario IESO	Price at the Independent Electricity Market Operator for Ontario (Ontario IESO) interface with the PJM Control Area
IP	Price at the IP interface with the ComEd Control Area in NI
IPPJMIMP	Price to import to the PJM Control Area from a control area in the southwest pricing point group: [IP - AEPNI + AEPVPIMP]
IPPJMEXP	Price to export from the PJM Control Area to a control area in the southwest pricing point group: [AEPVPEXP – AEPNI + IP]
MEC	Price at the MEC interface with the ComEd Control Area in NI
MECPJMIMP	Price to import to the PJM Control Area from a control area in the west pricing point group: [MEC – AEPNINI + AEPVPIMP]
MECPJMEXP	Price to export from the PJM Control Area to a control area in the west pricing point group: [AEPVPEXP – AEPNINI + MEC]
NIPS	Price at the Northern Indiana Public Service Company (NIPS) interface with the ComEd Control Area in NI, defined as the same as the price at the AEP interface with the ComEd Control Area
NYIS	Price at the NY interface with the PJM Control Area
NYISNIIMP	Price to import to the ComEd Control Area in NI from a control area in the northeast pricing point group: [NYIS – AEPVPEXP + AEPNI]
NYISNIEXP	Price to export from the ComEd Control Area in NI to a control area in the northeast pricing point group: [AEPNI – AEPVPIMP + NYIS]
WEC	Price at the WEC interface with the ComEd Control Area in NI
WECPJMIMP	Price to import to the PJM Control Area from a control area in the northwest pricing point group: [WEC – AEPNI + AEPVPIMP]
WECPJMEXP	Price to export from the PJM Control Area to a control area in the northwest pricing point group: [AEPVPEXP – AEPNI + WEC]

13 See generally PJM, "Draft ComEd Transmission and Market Integration White Paper, Version 2.3" (April 15, 2004), p. 78 < http://www.pjm.com/markets/market-integration/ downloads/documentation/comed-transmission-market-implement.pdf> (12.6 MB).

Phase 3 Integration of the AEP and DAY Control Zones[14]

With the integration of the AEP and DAY Control Zones, PJM became a single Control Area. The PJM Western Region then encompassed four control zones: the AEP, DAY, ComEd and AP Control Zones. Integration of the AEP and DAY Control Zones permitted all external control areas in a group to be mapped to one interface pricing point relative to the expanded PJM Control Area.

The PJM interface pricing points are applied to transactions based on the source (imports) and sink (exports) control areas associated with a particular transaction. Adjacent control areas, connected directly to the expanded PJM marketplace, have been grouped according to the electrical impact on PJM of transactions originating in each control area. This resulted in nine different interface pricing points. Control areas with similar impacts have been assigned to the same interface pricing point. These groupings are defined in Table D-2.

Table D-2 - AEP integration interface pricing point definitions[15]

Pricing Point	Included Control Areas
Northwest	Wisconsin Energy Corporation (WEC), Alliant East, Alliant West, MEC
Southwest	Central Illinois Light Company (CILCO), IP, Indianapolis Power & Light Company (IPL), Ameren, Cinergy (CIN), East Kentucky Power Cooperative, Louisville Gas & Electric Company (LG&E), Tennessee Valley Authority (TVA)
OVEC	Ohio Valley Electric Corporation (OVEC)
NIPSCO	Northern Indiana Public Service Company (NIPSCO)
Southeast	Carolina Power & Light Company (CPL) West (CP&LW), Carolina Power & Light Company (CPL) East (CP&LE), Duke Power (DUK), Dominion Virginia Power (DVP)
DLCO	Duquesne Light Company (DQE)
Ontario IESO	Ontario IESO
MICHFE	Michigan Electric Coordinated System, First Energy

The Coordinated Flowgates of PJM and the Midwest ISO

The flowgates where PJM and the Midwest ISO have agreed to take a coordinated response to congestion events are defined in a joint operating agreement between the two organizations.[16] Under its terms, PJM redispatches generation to reduce congestion at these facilities. As of October 29, 2004, there were 316 such flowgates.[17]

14 See generally PJM, "AEP & DP&L Transmission and Market Integration White Paper, Version 1.4" (September 24, 2004), p. 21 < http://www.pjm.com/ markets/market-integration/ downloads/ documentation/ 20040924-v67-aep-dpl-transmission-market-whitepaper-v14.pdf > (890 KB).
15 See Section 3, "Interchange Transactions," for a discussion of the evolution of pricing points during 2004.
16 See the "Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C." (December 31, 2003) < http://www.pjm.com/ documents/downloads/agreements/joa-complete.pdf > (906 KB). The document is herein called the JOA between the Midwest ISO and PJM.
17 Flowgates subject to coordination can be found through the PJM OASIS system. It can be accessed via eData although acceptance of the PJM usage agreement is necessary to reach the portion of the Web site where the list is maintained.

APPENDIX E - CAPACITY MARKETS[1]

Background

PJM and its members have long relied on capacity obligations as one of the methods to ensure reliability. Before retail restructuring, the original PJM members had determined their loads and related capacity obligations annually. Combined with state regulatory requirements to build and incentives to maintain adequate capacity, this system created a reliable pool, where capacity and energy were adequate to meet customer needs and where capacity costs were borne equitably by members and their loads.

Capacity obligations continue to be critical to maintaining reliability and to contribute to the effective, competitive operation of PJM Energy Markets. Adequate capacity resources, equal to or greater than expected load plus a reserve margin, help to ensure that energy is available on even the highest load days.

On January 1, 1999, in response to retail restructuring requirements, PJM introduced a transparent, PJM-run market in capacity credits.[2] New retail market entrants needed a way to acquire capacity credits to meet obligations associated with competitively gained load. Existing utilities needed a way to sell excess capacity credits when load was lost to new competitors. The PJM Capacity Credit Market provides a mechanism to balance supply and demand for capacity credits not met through the bilateral market or self-supply. The PJM Capacity Credit Market is designed to provide a transparent mechanism through which all competitors can buy and sell capacity based on need.

The “Reliability Assurance Agreement Among Load-Serving Entities in the PJM Control Area” (RAA) states that as competitive markets evolve the purpose of capacity obligations is:

> [to] ensure that adequate Capacity Resources will be planned and made available to provide reliable service to loads within the PJM Control Area, to assist other Parties during Emergencies and to coordinate planning of Capacity Resources consistent with the Reliability Principles and Standards. Further, it is the intention and objective of the Parties to implement this Agreement in a manner consistent with the development of a robust competitive marketplace.[3]

With the Phase 2 integration of the Commonwealth Edison Company (ComEd) into PJM on May 1, 2004,[4] the “PJM-West Reliability Assurance Agreement Among Load-Serving Entities in the PJM-West Region” was amended by Schedule 17.[5] It specified capacity market rules that would be implemented only in the ComEd Capacity Market during an interim 13-month period that will end on May 31, 2005. The market rules are specified in terms of installed rather than unforced capacity and

1 The PJM Capacity Market is the capacity market for all control zones except Commonwealth Edison Company (ComEd). It is referred to here as the PJM Capacity Market, the PJM Capacity Credit Market or simply PJM. The ComEd Capacity Market is an interim market limited to that control zone. It began on June 1, 2004, and will continue through May 31, 2005. On June 1, 2005, all control zones will participate in a single regional transmission organization (RTO) Capacity Market. Until then and for the purposes of the 2004 State of the Market Report, the interim capacity market is referred to as the ComEd Capacity Market, the ComEd Capacity Credit Market or simply ComEd.
Zones, control zones and control areas are geographic areas that customarily bear the name of a large utility service provider operating within their boundaries. The names apply to the geographic area, not to any single company. The geographic areas did not change with the formalization of the control zone and control area concepts during the Phase 3 integrations. For simplicity, zones are referred to as Control Zones for all three phases. The only exception is ComEd which is called the ComEd Control Area for Phase 2 only.

2 The first PJM Capacity Credit Markets (CCMs) were run in late 1998, with an effective date of January 1, 1999.

3 “Article 2, Purpose,” “Reliability Assurance Agreement among Load-Serving Entities in the PJM Control Area” (March 21, 2000), p. 8.

4 Since the ComEd Control Area’s Capacity Market did not open until June 1, 2004, throughout May the Commonwealth Edison Company covered all capacity obligations operating under the guidance of PJM. See “Schedule 17, Capacity Adequacy Standards and Procedures for the Commonwealth Edison Zone during the Interim Period.” See also “PJM West Reliability Assurance Agreement Among Load-Serving Entities in the PJM West Region,” Section L (December 20, 2004), pp. 48C – 48D.

5 “Schedule 17, Capacity Adequacy Standards and Procedures for the Commonwealth Edison Zone During the Interim Period.” See also “PJM West Reliability Assurance Agreement Among Load-Serving Entities in the PJM West Region” (December 20, 2004), pp. 48A – 48D.

operate on a monthly basis. The ComEd Capacity Credit Market does not include the Daily Capacity Credit Market Auctions that are a feature of the Capacity Credit Market in the rest of PJM. Beginning on June 1, 2005, however, when the interim market ends, all ComEd Control Zone capacity transactions and obligations will operate under the PJM Capacity Market rules then in effect.

Under the RAA governing both Capacity Markets operated by the PJM regional transmission organization (RTO), each load-serving entity (LSE) must own or purchase capacity resources greater than, or equal to, its capacity obligation. To cover this responsibility, LSEs may own or purchase capacity credits, unit-specific capacity or capacity imports.

Capacity Obligations

For the PJM and ComEd Capacity Markets, a load forecast is used to determine the forecast peak load. In both Capacity Markets, these forecast peak-load values are further adjusted to establish capacity obligations.

- **The PJM Capacity Market.** The adjusted forecast peak-load value[6] is multiplied by the forecast pool requirement (FPR) to determine the unforced capacity obligation. The FPR is equal to one plus a reserve margin, multiplied by the PJM unforced outage factor. An LSE's unforced capacity obligation is its forecast peak load multiplied by the FPR. The FPR is set for each planning period which commences every June 1.

- **The ComEd Capacity Market.** The adjusted forecast peak-load value is multiplied by an installed reserve margin (IRM) to determine the capacity obligation. The IRM is equal to one plus a reserve margin. The IRM was set for three consecutive intervals: a 1.15 IRM for the summer interval running from June 1, 2004, through September 30, 2004; a 1.4 IRM for the fall interval running from October 1, 2004, through December 31, 2004: and a 1.4 IRM for the winter interval running from January 1, 2005, through May 31, 2005.

  Each individual LSE's capacity obligation is based on its customers' aggregate share of the summer interval's forecasted peak load multiplied by the IRM. The amount is further adjusted for mandatory interruptible load (MIL). This allocation is also used to determine adjusted peak-load values for the fall and winter intervals.

Meeting Capacity Obligations

- **The PJM Capacity Market.** In this Capacity Market, an LSE's load can change on a daily basis as customers switch suppliers. The unforced capacity position of every such LSE is calculated daily when its capacity resources are compared to its capacity obligation to determine if any LSE is short of capacity resources. Deficient entities must contract for capacity resources to satisfy their deficiency. Any LSE that remains deficient must pay an interval penalty equal to the capacity deficiency rate (CDR) times the number of days in an interval.[7] If an LSE is short because of a short-term load increase, it pays only the daily penalty until the end of the month. In no case is a deficient LSE charged more than the CDR multiplied by the number of days in the interval, multiplied by each MW of deficiency.

6 Adjusted for active load-management (ALM) and local diversity.
7 The CDR is a function both of the annual carrying costs of a combustion turbine (CT) and the forced outage rate and thus may change annually. The CDR was changed to $170.96 per MW-day, effective June 1, 2003, and to $170.09 per MW-day, effective June 1, 2004.

- **The ComEd Capacity Market.** By contrast, in this Capacity Market, an LSE's load can only change monthly to reflect load shifts between LSEs as customers switch suppliers. In the ComEd Capacity Market, installed capacity rather than unforced capacity is used to meet capacity obligations. Deficient entities must contract for capacity resources to satisfy their deficiency. Any LSE that remains deficient must pay a deficiency charge equal to the MW of deficiency times the daily deficiency rate,[8] times the number of days in the interval.

Capacity Resources

Capacity resources are defined as MW of net generating capacity meeting PJM-specific criteria. They may be located within or outside of PJM, but they must be committed to serving load within PJM. All capacity resources must pass tests regarding the capability of generation to serve load and to deliver energy. This latter criterion requires adequate transmission service.[9]

Capacity resources may be owned, or they may be bought in three different ways:

- **Bilateral, from an internal PJM source.** Internal, bilateral purchases may be in the form of a sale of all or part of a specific generating unit, or in the form of a capacity credit, measured in MW and defined in terms of unforced capacity for the PJM Capacity Market or in terms of installed capacity for the ComEd Capacity Market.

- **Bilateral, from a generating unit external to PJM.** External, bilateral purchases (capacity imports) must meet PJM criteria, including that imports are from specific generating units and that sellers have firm transmission from the identified units to the metered boundaries of the RTO.

- **Capacity Credit Markets.** For the PJM Capacity Market, market purchases may be made from the Daily, Monthly or Multimonthly Capacity Credit Market Auctions. For the ComEd Capacity Market, market purchases may be made from the ComEd Monthly or Multimonthly Capacity Credit Market Auctions.

The sale of a generating unit as a capacity resource within the PJM Control Area entails obligations for the generation owner. The first four of these requirements as listed below are essential to the definition of a capacity resource and contribute directly to system reliability.

- **Energy Recall Right.** PJM rules specify that when a generation owner sells capacity resources from a unit, the seller is contractually obligated to allow PJM to recall the energy generated by that unit if the energy is sold outside of PJM. This right enables PJM to recall energy exports from capacity resources when it invokes emergency procedures.[10] The recall right establishes a link between capacity and actual delivery of energy when it is needed. Thus, PJM can call upon energy from all capacity resources to serve load within the Control Area. When PJM invokes the recall right, the energy supplier is paid the PJM real-time energy market price.

- **Day-Ahead Energy Market Offer Requirement.** Owners of PJM capacity resources are required to offer their output into PJM's Day-Ahead Energy Market. When LSEs purchase

8 Effective June 1, 2004, the daily deficiency rate is $160.00 per MW-day.
9 See PJM "Reliability Assurance Agreement," "Capacity Resources" (May 17, 2004), p. 2.
10 See PJM "PJM Manual 13, Emergency Operations, Revision 19" (October 1, 2004) <http://www.pjm.com/ contributions/pjm-manuals/pdf/m13v19.pdf> (461 KB).

capacity, they ensure that resources are available to provide energy on a daily basis, not just in emergencies. Since day-ahead offers are financially binding, PJM capacity resource owners must provide the offered energy at the offered price if the offer is accepted in the Day-Ahead Energy Market. This energy can be provided by the specific unit offered, by a bilateral energy purchase, or by an energy purchase from the Real-Time Energy Market.

- **Deliverability.** To qualify as a PJM capacity resource, energy from the generating unit must be deliverable to load in the PJM Control Area. Capacity resources must be deliverable,[11] consistent with a loss of load expectation as specified by the reliability principles and standards, to the total system load, including portion(s) of the system that may have a capacity deficiency. In addition, for external capacity resources used to meet an accounted-for obligation within PJM, capacity and energy must be delivered to the metered boundaries of the RTO through firm transmission service.

- **Generator Outage Reporting Requirement.** Owners of PJM capacity resources are required to submit historical outage data to PJM pursuant to Schedule 12 of the RAA.[12]

- **Financial Transmission Right.** Until the Auction Revenue Right (ARR) allocation rules were implemented on June 1, 2003, a Financial Transmission Right (FTR) was available to load only if a specific capacity resource was identified as the source of the delivered energy.[13] Since a capacity credit is not unit-specific, it could not be the basis for an FTR. Under ARR allocation rules in effect before June 1, 2004, an ARR was available to load only if a specific capacity resource was identified as the source of the delivered energy. The most recent modification of the ARR allocation rules, which became effective June 1, 2004, severed the link between capacity resources and ARRs. After June 1, 2004, customers may request ARRs from the resources that were historically designated to serve load in a transmission zone or a load aggregate.

Market Dynamics

RAA procedures determine the total capacity obligation for both the PJM and the ComEd Capacity Markets and thus the total demand for capacity in each market. The RAA includes rules for allocating total capacity obligation to individual LSEs in each market. An LSE's deficiency, in either market, is equivalent to its allocated capacity obligation, net of bilateral contracts, self-supply and the applicable active load management (ALM in the PJM Capacity Market) or mandatory interruptible load (MIL in the ComEd Capacity Market). LSEs bid this deficiency into the appropriate Capacity Credit Market Auctions.

The supply of capacity credits in either Capacity Credit Market is a function of:

- Physical capacity in the control area;

- Prices of energy and capacity in external markets;

- Prices in the PJM Energy and Capacity Markets;

11 Deliverable per Schedule 10, PJM "Reliability Assurance Agreement" (May 17, 2004), p. 52 <http: //www.pjm.com/documents/downloads/agreements/raa.pdf> (344 KB).
12 See Schedule 12, PJM "Reliability Assurance Agreement" (May 17, 2004), p. 57 <http: //www.pjm.com/documents/downloads/agreements/raa.pdf> (344 KB).
13 See Section 7, "Financial Transmission and Auction Revenue Rights."

- Capacity resource imports and exports; and

- Transmission service availability and price.

While physical generating units in PJM are the primary source of capacity resources, capacity resources can be exported from PJM and imported into PJM, subject to transmission limitations. It is the ability to export and to import capacity resources that makes capacity supply in PJM a function of price in both internal and external capacity and energy markets.

In capacity markets, as in other markets, market power is the ability of a market participant to increase market price above the competitive level. The competitive market price is the marginal cost of producing the last unit of output, assuming no scarcity and including opportunity costs. For capacity, the opportunity cost of selling into both Capacity Markets operated by the RTO is the additional revenue foregone by not selling into an external energy and/or capacity market.

Generation owners can be expected to sell capacity into the most profitable market. The competitive price in the capacity markets is a function of the marginal cost of capacity. The marginal cost of capacity is, in turn, determined by the time period over which a choice is made as well as by the alternative opportunities available to the generation owner. If an owner is considering whether to sell a capacity resource for a year, marginal cost would include the incremental cost of maintaining the unit (going forward cost) so that it can qualify as a capacity resource, and any relevant opportunity cost. If an owner is considering whether to sell a capacity resource for a day, the only relevant cost is the opportunity cost. The opportunity cost associated with the sale of a capacity resource is a function of the expected probability that the energy will be recalled and the expected distribution of the difference between external and internal energy prices.

Generators can be expected to evaluate the opportunities to sell capacity on a continuing basis, over a variety of time frames, depending on the rules of the capacity markets. The existence of interval markets makes the generators' decisions more dependent on assessments of seasonal energy market price differentials and recall probabilities. With longer capacity obligations, the likelihood of the net external price differential exceeding the capacity penalty for the period is lower and, therefore, the incentives to sell the system short are lower.

APPENDIX F - ANCILLARY SERVICE MARKETS

This appendix covers two subject areas: area control error and the details of regulation availability and price determination.

Area Control Error (ACE)

Area control error (ACE) is a real-time metric used by PJM operators to measure the imbalance between load and generation. ACE is the instantaneous MW imbalance between generation and load plus net interchange. PJM dispatchers seek to minimize ACE. A dispatcher's success in doing so is measured by control performance standards (CPS) that are mandated by the North American Electric Reliability Council (NERC).

The primary tool used by dispatchers to minimize ACE is regulation. Regulation is defined as a variable amount of generation energy under automatic control which is independent of economic cost signal and is obtainable within five minutes. Regulation contributes to maintaining the balance between load and generation by moving the output of selected generators up and down via an automatic generation control (AGC) signal.[1]

Generators wishing to participate in the Regulation Market must pass certification and submit to random testing. Certification requires that generators be capable of and responsive to AGC. After receiving certification, all participants in the Regulation Market are tested to ensure that regulation capacity is fully available at all times. Testing occurs at times of minimal load fluctuation. Units are subjected to a regulation test pattern for 40 minutes.[2] Units must reach their regulation levels up and down, within five minutes. Unit response is monitored. Units whose response is less than their offered regulation capacity have their regulating capacity reduced by PJM operators.

Control Performance Standard (CPS)

Two control performance standards are established by NERC for evaluating ACE control. One measure is a statistical measure of ACE variability and its relationship to frequency error. The second measure is a statistical measure of unacceptably large, net unscheduled power flows. These two measures define the NERC Control Performance Standard. The NERC Control Performance Standard is the measure against which all control areas are evaluated.

- **CPS1.** NERC requires that the first measure of the CPS survey provide a measure of the control area's performance. The measure is intended to provide the control area with a frequency-sensitive evaluation of how well it met its demand requirements. A minimum passing score for CPS1 is 100 percent. (The formal definition of CPS1 can be found in "NERC Performance Standards Document," volume 2 (November 21, 2002), Section B.1.1.1.)[3]

- **CPS2.** NERC also requires that the second measure of the CPS survey be designed to bound ACE 10-minute averages. CPS2 provides a control measure of excessive, unscheduled power flows that could result from large ACEs. (The formal definition of CPS2 can be found in "NERC Performance Standards Reference Document," volume 2 (November 21, 2002), Section

1 Regulation market business rules are defined in "PJM Manual 11: Scheduling Operations," Revision 23 (December 7, 2004), pp 47-55.
2 See "PJM Dispatching Operations Manual, M-12," Revision 10, Section 4 (March 3, 2004), p. 44.
3 For more information about the definition and calculation of CPS, refer to "M12: Dispatching Operations," revision 11 (January 01, 2005), pp. 19-21.

B.1.1.2.) CPS2 is measured by counting the number of 10-minute periods during a month when the 10-minute average of the PJM Control Area's ACE is within certain defined limits known as "L10." The specific, 10-minute periods of each hour are those ending at 10, 20, 30, 40, 50 and 60 minutes after the hour. A passing score for CPS2 is achieved when 90 percent of these 10-minute periods during a single month are within "L10." During Phases 1 and 2 of 2004, the PJM Control Area's "L10" standard was 194 MW. During Phase 3, PJM's "L10" standard was 254 MW.

PJM's CPS Performance

As Figure F-1 and Figure F-2 show, PJM generally performed well in 2004 against the CPS1 and CPS2 metrics. Nonetheless, the Phase 2 integration of the Commonwealth Edison Company (ComEd) Control Area and the Phase 3 integration of the AEP and DAY Control Zones into the PJM Control Area created two especially difficult problems. First, the establishment of the ComEd Control Area left that region without enough available regulation to meet the regulation requirement. The subsequent incorporation of the ComEd, AP, AEP and DAY Control Zones into a single PJM Control Area during Phase 3 required PJM to adapt its frequency management to a new frequency bias constant and new interchange transaction characteristics.

Figure F-1 - PJM CPS1 and CPS2 performance: Calendar years 2001 to 2004

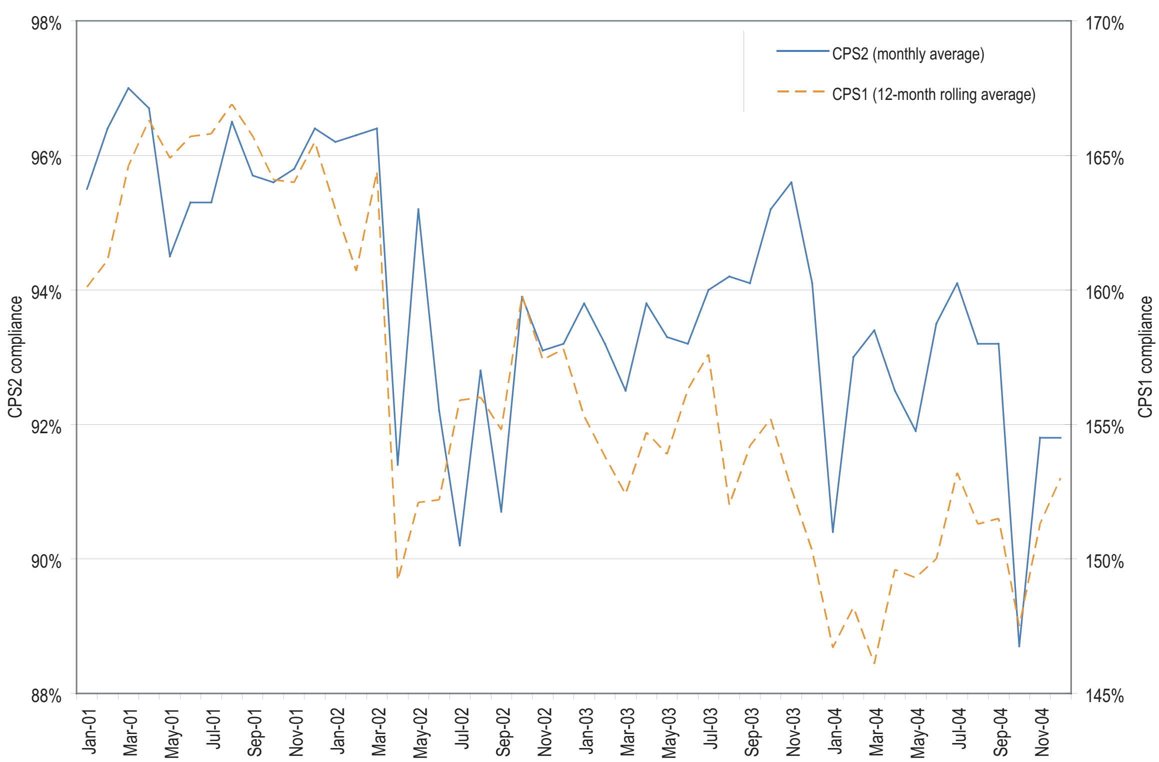
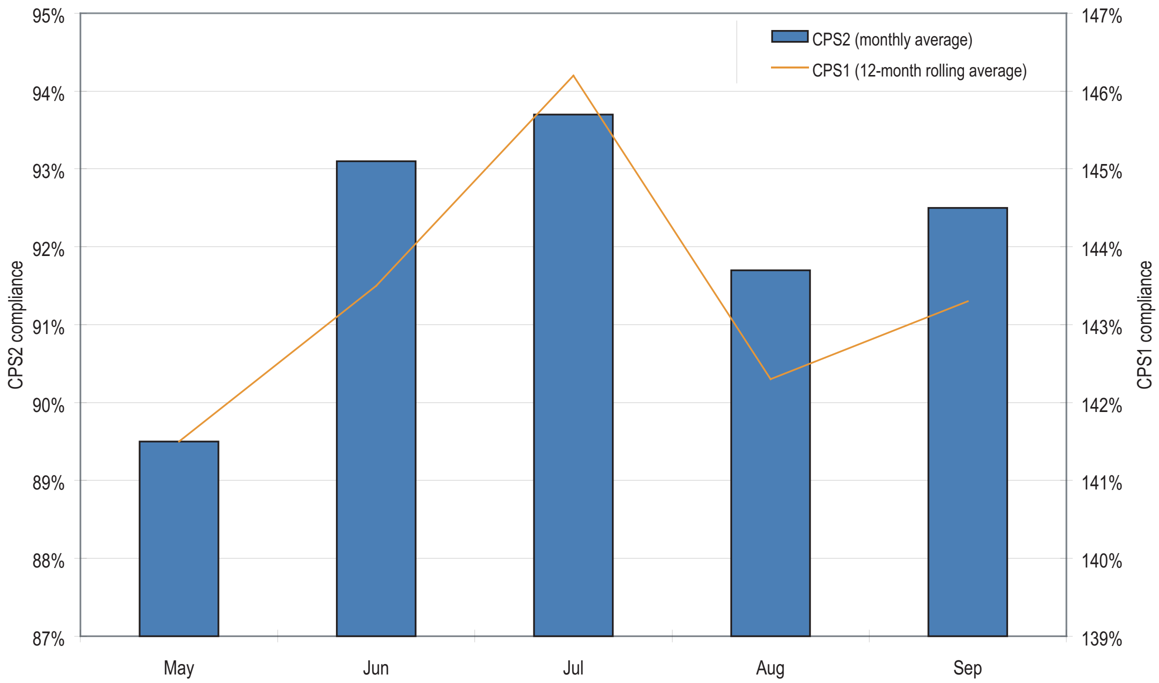
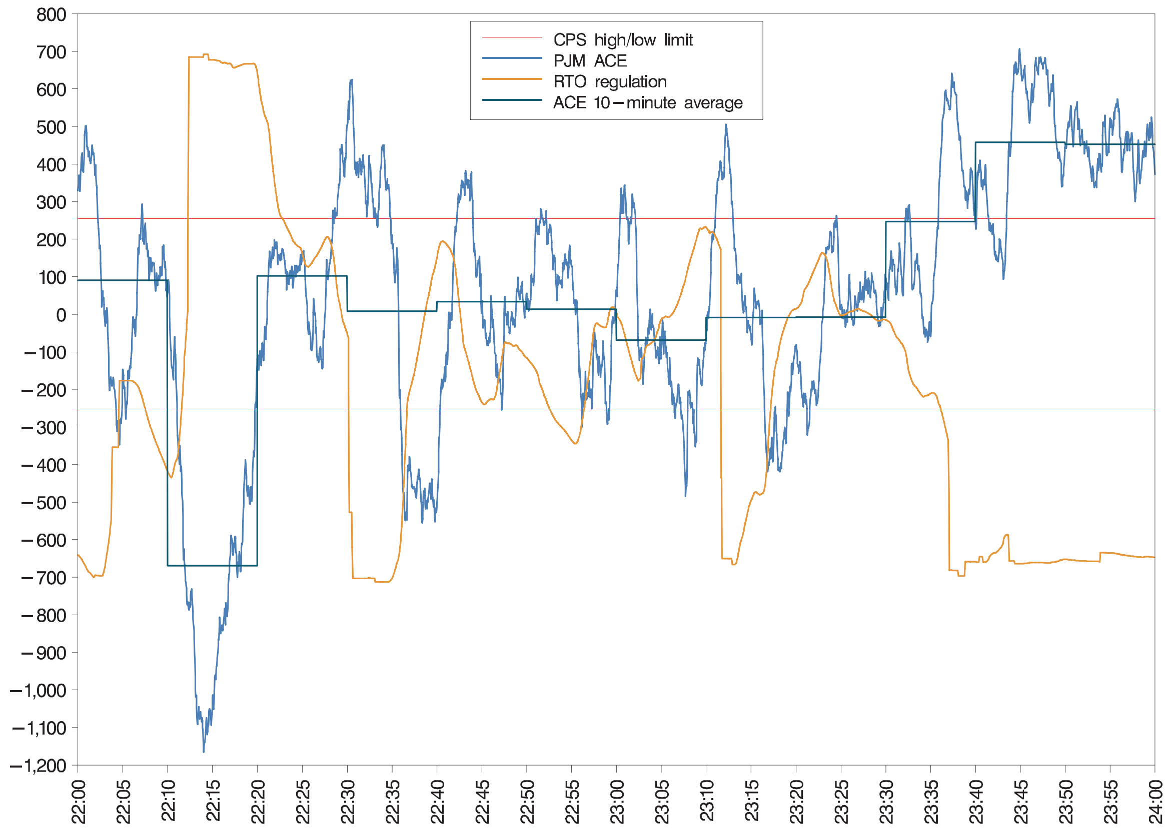


Figure F-2 - ComEd Control Area CPS1 and CPS2 performance: Phase 2, 2004



ACE is controlled by PJM's regulation AGC signal, which is updated every four seconds. ACE is particularly difficult to control during times of rapid change in load. Figure F-3 shows PJM ACE plotted against the regulation AGC signal during a period of rapid load change on October 12, 2004, in the hours ending 2300 and 2400 Eastern Prevailing Time (EPT).

Figure F-3 - PJM ACE vs. regulation signal sample: October 12, 2004



As PJM has learned, ACE has a complex relationship with the structure of the grid. Its control parameters can change in unexpected ways when the grid is expanded or altered significantly. Figure F-3 shows the regulation AGC signal (gold line), the ACE (blue line), the pass or fail CPS2 "L10" limits (red lines) and the 10-minute ACE average forming the basis for CPS2 (gray line). This two-hour segment includes three CPS2 violations at 2210 to 2220 (low ACE), at 2340 to 2350 (high ACE) and at 2350 to 2400 EPT (high ACE) on October 12, 2004. By comparing the ACE response (blue line) to the regulation signal (gold line), one can see that ACE generally reacted well to the regulation signal. Under the circumstance, regulation was adequate.

It is especially difficult to control ACE during periods of rapid change in control area load. Hours ending 2300 and 2400 EPT are normally times when load ramps down quickly. Figure F-3 shows that during these hours on October 12, 2004, ACE remained above the "L10" CPS2 limit despite a maximum corrective regulation signal. The result was two consecutive CPS2 violations at 23:40 and 23:50. Other factors affect ACE, including external transactions, system disturbances created by a unit or transmission line outage, and insufficient regulation available. The latter can be alleviated by spinning reserve, but it responds more slowly than regulation. In these cases, ACE can exceed acceptable limits for a short time even though regulation levels are adequate for short-term ACE control.

ACE is related not just to load and generation imbalance, but also to frequency bias and to discrepancies between scheduled and actual tie line flows.

Monthly CPS2 Violations for 2004

PJM had two monthly CPS violations during 2004. The first occurred in May 2004 and involved a violation of the CPS2 criterion in the ComEd Control Area. The second occurred in October 2004 and involved a violation of the CPS2 criterion for the PJM Control Area.

ComEd Control Area in May

PJM's May 2004 performance in the ComEd Control Area reached 89.5 percent, 0.5 percent below a passing 90 percent CPS2 performance standard. That CPS2 violation had two root causes. Initially, an adequate supply of regulation was unavailable. This situation improved during the five-month period of Phase 2 when ComEd was a separate Control Area. The percentage of hours during each month when there was a deficit of assigned regulation was: May with 36 percent, June with 22 percent, July with 18 percent, August with 16 percent and September with 2.4 percent. It should be noted that despite these deficits in assigned regulation, the actual regulation in the ComEd Control Area (150 MW off peak and 300 MW on peak) was more than adequate to control ACE.

The second root cause for the May 2004 CPS2 violation was a 94 percent load forecasting performance (97 percent is PJM's goal).[4] The load forecasting performance was the result of an initial inability to anticipate interchange ramp changes into the ComEd Control Area and local load behavior. The problem abated as PJM operators gained more experience in ComEd operations.

PJM Control Area in October

PJM Mid-Atlantic's October 2004 CPS2 score was 88.7, which is 1.3 percent below the passing score of 90 percent. Satisfaction of NERC CPS standards involves more than an adequate supply of regulation. Since the Phase 3 consolidation of the ComEd, AP, AEP and DAY Control Zones into the PJM Control Area, regulation supply has been adequate. Nonetheless, PJM failed CPS2 in October because PJM had to adapt its frequency management to a new frequency bias constant and new interchange transaction characteristics.

The frequency bias constant increased after October 1, 2004, rising to 1,131 MW per 0.1 hertz from 655 MW per 0.1 hertz. This required PJM to respond to frequency deviation much more quickly than any other control area in the Eastern Interconnection because the same deviation in frequency results in a significantly greater deviation in ACE for PJM. The higher frequency bias caused PJM's AGC to respond too quickly to the frequency component of ACE, increasing its momentary corrective response at the expense of exacerbating ACE oscillations longer term.

This problem was mitigated by adjusting AGC tuning parameters on October 20, 2004, to increase the responsiveness of the regulation control signal. Additional adjustments to the AGC tuning parameters were implemented on November 5, 2004. Further mitigation was accomplished by

4 See "PJM Manual 11: Scheduling Operations," Revision 23 (December 7, 2004), pp.72-73, for a full description of the load forecasting procedure.

temporarily increasing the amount of required regulation in the PJM Mid-Atlantic Region to 1.1 percent of forecast load plus 175 MW on November 19, 2004, and in ComEd to 1 percent of forecast peak load plus 175 MW. This increase was lessened on December 16, 2004, to 1.1 percent of forecast load plus 125 MW for the PJM Mid-Atlantic Region and 1 percent of forecast peak load plus 125 MW for ComEd.

Regulation Capacity, Daily Availability, Hourly Supply and Price

Regulation market-clearing price (RMCP) is determined algorithmically by the PJM Market Operations Group by first creating a supply curve of available units and their associated regulation prices, then assigning regulation to units in increasing order of price until the regulation MW requirement is satisfied. The price of the most expensive unit required to satisfy the regulation requirement is the RMCP.

The process by which available regulation is defined and assigned is complicated, but important to understanding regulation price and Regulation Market competitiveness.

- **Regulation Capacity.** A database of all generating units in a control zone is maintained by PJM's generation group. Generating units which have qualified to participate in the Regulation Market are identified. The sum of the regulation MW capability of these units is the theoretical maximum regulation capacity in that control zone. Actual regulation capacity varies over time because units that become certified for regulation may then be decommissioned, taken offline, fail regulation testing or be removed from the Regulation Market by their owners.

- **Regulation Daily Availability.** All owners of generating units in the regulation capacity pool as defined above have the right to offer their regulation capacity daily into the Regulation Market using the PJM Market User Interface. Daily regulation availability is the sum of all regulation-capable units that offer regulation into the market. Units that have entered bids into the PJM Market User Interface system have the right to set themselves to "unavailable" for regulation for the day, or for a specific hour or set of hours. They also have the right to change the amount of regulation MW offered. They do not have the right to change their regulation offer price during a day. All regulation bids are summed to calculate the total daily regulation available, a figure that changes each day.

- **Regulation Hourly Supply, Assignment and RMCP.** Sixty minutes before the market hour, PJM runs spinning and regulation market-clearing software (SPREGO) to determine the amount of regulation required, generate the regulation supply curve, assign regulation to specific units and determine the RMCP. This actual process is complicated but spinning and regulation are cooptimized for a solution that minimizes the total cost of both products. During this process, PJM dispatchers can deselect units from SPREGO for any of several reasons including: 1) to control transmission constraints; 2) to avoid overgeneration during periods of minimum generation alert; 3) to remove a unit temporarily unable to regulate; or 4) to remove a unit with a malfunctioning unit-to-PJM data link.

The spinning and regulation requirements are:

- **For regulation:**

  PJM Mid-Atlantic Region. For on-peak hours (0500 through 2359 EPT) 1.1 percent of the forecast peak load, and for off-peak hours (0000 through 0459 EPT) 1.1 percent; and

  PJM Western Regulation Market. Regardless of hour, 1.0 percent of the forecast peak load.

- **For spinning reserve:**

  PJM. Used in calculating a requirement that is 75 percent of the largest contingency, provided that double the remaining 25 percent is available for nonsynchronized, 10-minute reserve.

All regulation resource units which have bid into the daily Regulation Market are evaluated by SPREGO for regulation. SPREGO then excludes units according to the following ordered criteria:

1. The availability status of the unit as listed in the daily bid table and the hourly update table. Any unit which is set to “available” in the hourly update table is included in the list. Any unit which is set to “unavailable” in the hourly update table is excluded from the list. Any unit which has no entry in the hourly update table, but is set to “unavailable” in the daily bid table is excluded from the list.

2. If the unit is a combustion turbine generator or a steam generator and its economic maximum generation MW level is not set higher than its economic minimum generation MW level, then the unit is excluded from regulation consideration.

3. The unit must be on, unless it is a combustion turbine generator.

4. The unit must not have been assigned to spin.

Applying these exclusionary rules further diminishes the available regulation used by SPREGO in assigning regulation and in clearing the market to determine the price. The units that remain are the supply, and they are used by SPREGO to clear the market and to determine price.

For each generating unit in the supply, the regulation offer price is calculated using the sum of the unit’s regulation offer cost and the OC based on the forecast LMP. The OC calculator also needs data such as economic minimum and economic maximum, regulation minimum and regulation maximum, startup costs and cost-schedule data. Finally, the MW offered and the calculated regulation price are used to create a regulation supply curve in which the MW offered are plotted against price. Units are assigned in order of price from the lowest price until the amount of required regulation has been assigned.

APPENDIX G - FTR AND ARR MARKETS

The procedure for prorating ARRs when transmission capability limits the amount of ARRs that can be allocated is illustrated here, as is the establishment of ARR target allocations and credits through the Annual FTR Auction.

ARR Prorating Procedure Illustration

Table G-1 provides an illustration of the prorating procedure for ARRs. If line A-B has a 100 MW rating, but ARR requests from two customers together would impose 175 MW of flow on it, the service request would exceed its capability by 75 MW. The first customer's ARR request (ARR #1) is for a total of 300 MW with a 0.50 impact on the constrained line. It would thus impose 150 MW of flow on the line. The second customer's request (ARR #2) is for a total of 100 MW with a 0.25 impact and would impose an additional 25 MW on the constrained line. An allocation based only on the number of ARRs requested would assign three times as many ARRs to the first customer as to the second (300/100 = 3). An allocation based solely on the per unit MW impact would assign half as many ARRs to the first customer as to the second [(1 / 0.5) / (1 / 0.25) = 0.5]. The actual allocation considers these factors together, resulting in the first customer receiving 1.5 times as many ARRs as the second.

Table G-1 - ARR allocation prorating procedure: Illustration

Line A-B Rating = 100 MW						
ARR #	Path	Per MW Effect on Line A-B	Requested ARRs	Resulting Line A-B Flow	Prorated ARRs	Prorated Line A-B Flow
1	C-D	0.50	300	150	150	75
2	E-F	0.25	100	25	100	25
Sum			400	175	250	100

The *pro rata* equation would be solved for each request as follows:

Individual *pro rata* MW = (Line capability) * (Individual requested MW / Total requested MW) * (1 / per MW effect on line)

ARR #1 *pro rata* MW award = (100 MW) * (300 MW / 400 MW) * (1 / 0.50) = 150 MW

ARR #2 *pro rata* MW award = (100 MW) * (100 MW / 400 MW) * (1 / 0.25) = 100 MW

Together the *pro rata*, awarded ARRs would impose a flow equal to line A-B's capability (150 MW * 0.50 + 100 MW * 0.25 = 100 MW).

ARR Credit Illustration

Table G-2 illustrates how ARR target allocations are established, how FTR auction revenue is generated and how ARR credits are determined. FTRs pay and ARRs are paid based on cleared nodal prices from the Annual FTR Auction. If total revenue from the auction is greater than the sum of ARR target allocations, then the surplus is used to offset any FTR congestion credit deficiencies that occur in the hourly Day-Ahead Energy Market.

Table G-2 - ARR credits: Illustration

Path	Annual FTR Auction Path Price	ARR MW	ARR Target Allocation	FTR MW	FTR Auction Revenue	ARR Credits
A-C	$10	10	$100	10	$100	$100
A-D	$15	10	$150	5	$75	$150
B-D	$10	0	$0	20	$200	$0
B-E	$15	10	$150	5	$75	$150
Total			$400		$450	$400
ARR Payout Ratio = ARR Credits/ARR Target Allocations = $400/$400 = 100%						
Surplus ARR Revenue = FTR Auction Revenue - ARR Credits = $450 - $400 = $50						

APPENDIX H - GLOSSARY

Active load management (ALM)	Retail customer load that can be interrupted at the request of PJM. Such a PJM request is considered an emergency action and is implemented prior to a voltage reduction. ALM derives an ALM credit in the accounted-for-obligation.
Aggregate	Combination of buses or bus prices.
Ancillary service	Those services necessary to support the transmission of capacity and energy from resources to loads while, in accordance with good utility practice, maintaining reliable operation of the transmission provider's transmission system.
Ancillary service area	A defined market service area for ancillary services including regulation and spinning.
Area control error (ACE)	Area control error (ACE) is a real-time metric used by PJM operators to measure the imbalance between load and generation. ACE is the instantaneous MW imbalance between generation and load plus net interchange.
Auction Revenue Right (ARR)	A financial instrument entitling its holder to auction revenue from Financial Transmission Rights (FTRs) based on locational marginal price (LMP) differences across a specific path in the Annual FTR Auction.
Automatic generation control (AGC)	An automatic control system comprised of hardware and software. Hardware is installed on generators allowing their output to be automatically adjusted and monitored by an external signal and software is installed facilitating that output adjustment.
Average hourly unweighted LMP	An LMP calculated by averaging hourly LMP with equal hourly weights.
Basic generation service (BGS)	The default electric generation service provided by the electric public utility to consumers who do not elect to buy electricity from a third-party supplier.
Bilateral agreement	An agreement between two parties for the sale and delivery of a service.

Black start unit	A generating unit with the ability to go from a shutdown condition to an operating condition and start delivering power without assistance from the transmission system.
Bottled generation	Economic generation that cannot be dispatched because of local operating constraints.
Burner tip fuel price	The cost of fuel delivered to the generator site equaling the fuel commodity price plus all transportation costs.
Bus	An interconnection point.
Capacity credit	An entitlement to a specified number of MW of unforced capacity from a capacity resource for the purpose of satisfying capacity obligations imposed under the RAA.
Capacity deficiency rate (CDR)	The capacity deficiency rate is based on the annual carrying charges for a new combustion turbine, installed and connected to the transmission system. To express the CDR in terms of unforced capacity, it must be further divided by the quantity 1 minus the EFORd.
Capacity Markets	All markets where PJM members can trade capacity.
Capacity queue	A collection of RTEPP capacity resource project requests received during a particular timeframe and designating an expected in-service date.
Combined cycle (CC)	A generating unit generally consisting of a gas-fired turbine and a heat recovery steam generator. Electricity is produced by a gas turbine whose exhaust is recovered to heat water, yielding steam for a steam turbine that produces still more electricity.
Combustion turbine (CT)	A generating unit in which a combustion turbine engine is the prime mover.
Control zone	An area within the PJM Control Area, as set forth in the PJM Open Access Tariff and the Reliability Assurance Agreement (RAA). Schedule 16 of the RAA defines the distinct zones that comprise the PJM Control Area.
Decrement bids	Financial offers to purchase specified amounts of MW in the Day-Ahead Energy Market at, or above, a given price.

1 New York Independent System Operator, "Definitions/Glossary" (February 23, 2004) < http://www.nyiso.com/services/training/glossary/index.html >.

Dispatch rate	Control signal, expressed in dollars per MWh, calculated by PJM and transmitted continuously and dynamically to generating units to direct the output level of all generation resources dispatched by the PJM Office of the Interconnection.
Disturbance control standard	A NERC-defined metric measuring the ability of a control area to return area control error (ACE) either to zero or to its predisturbance level after a disturbance such as a generator or transmission loss.
Eastern Prevailing Time	Eastern Prevailing Time (EPT) is equivalent to Eastern Standard Time (EST) or Eastern Daylight Time (EDT) as is in effect from time to time.
End-use customer	Any customer purchasing electricity at retail.
External resource	A resource located outside metered PJM boundaries.
Financial Transmission Right (FTR)	A financial instrument entitling the holder to receive revenues based on transmission congestion measured as hourly energy LMP differences in the PJM Day-Ahead Energy Market across a specific path.
Firm point-to-point transmission	Firm transmission service that is reserved and/or scheduled between specified points of receipt and delivery.
Firm transmission	Transmission service that is intended to be available at all times to the maximum extent practicable. Service availability is, however, subject to an emergency, an unanticipated failure of a facility or other event.
Fixed-demand bid	Bid to purchase a defined MW level of energy, regardless of LMP.
Generation offers	Schedules of MW offered and the corresponding offer price.
Generator owner	A PJM member that owns or leases, with rights equivalent to ownership, facilities for generation of electric energy that are located within PJM.

Gross deficiency	The sum of all companies' individual capacity deficiency, or the shortfall of unforced capacity below unforced capacity obligation. The term is also referred to as accounted-for deficiency.
Gross excess	The sum of all LSE's individual excess capacity, or the excess of unforced capacity above unforced capacity obligation. The term is referred to as "Accounted-for Excess" in the "PJM Accounted-For Obligation Manual" (Manual 17).
Gross export volume (energy)	The sum of all export transaction volume (MWh).
Gross import volume (energy)	The sum of all import transaction volume (MWh).
Herfindahl-Hirschman Index (HHI)	HHI is calculated as the sum of the squares of the market share percentages of all firms in a market.
Hertz	Electricity system frequency is measured in hertz.
HRSG	Heat recovery steam generator. An air-to-steam heat exchanger installed on combined-cycle generators.
Increment offers	Financial offers in the Day-Ahead Energy Market to supply specified amounts of MW at, or above, a given price.
Initial threshold	In the context of the PJM economic planning process, when the cumulative gross congestion cost of a constraint exceeds the applicable initial threshold, PJM begins determining the extent to which the load affected by that constraint is unhedgeable. Initial threshold values are specific to the transmission level voltage of the affected facility.
Installed capacity	System total installed capacity measures the sum of the installed capacity (in installed, not unforced, terms) from all internal and qualified external resources designated as PJM capacity resources.
Interval Market	The Capacity Market rules provide for three Interval Markets, covering the months from January through May, June through September and October through December.

Load	Demand for electricity at a given time.
Load aggregator	An entity licensed to sell energy to retail customers located within the service territory of a local distribution company.
Load-serving entity (LSE)	Load-serving entities provide electricity to retail customers. Load-serving entities include traditional distribution utilities and new entrants into the competitive power markets.
Lost opportunity cost	The difference in net compensation from the energy market between what a unit receives when providing regulation or spinning reserve and what it would have received for providing energy output.
Mandatory interruptible load (MIL)	MIL is retail customer load in ComEd that can be interrupted at the request of PJM. PJM members commit to reduce load by a fixed MW amount or to a certain MW load or to initiate cycling of end-use equipment when called upon by PJM. The account of the LSE which nominated the customer's load drop is credited the MW amount committed. The credit can either be traded or used to meet the member's capacity obligation. Performance is measured, and penalties are charged for under compliance and payments are made for over compliance.
Marginal unit	The last generation unit to supply power under a merit order dispatch system.
Market-clearing price	The price that is paid by all load and paid to all suppliers.
Market participant	A PJM market participant can be a market supplier, a market buyer or both. Market buyers and market sellers are members that have met reasonable creditworthiness standards as established by the PJM Office of the Interconnection. Market buyers are otherwise able to make purchases and market sellers are otherwise able to make sales in the PJM Energy or Capacity Credit Markets.
Market threshold	In the context of the PJM economic planning process, each market threshold represents the level of unhedgeable congestion costs that triggers the start of a one-year "market window" for the development of market solutions to unhedgeable congestion. Market threshold values are specific to the transmission voltage of the affected facility.

Market user interface	A thin client application allowing generation marketers to provide and to view generation data, including bids, unit status and market results.
Market window	In the context of the PJM economic planning process, the period of time during which PJM allows for the development of market solutions to unhedgeable congestion associated with an affected facility.
Merchant solution	In the context of the PJM economic planning process, a solution proposed to reduce or to eliminate unhedgeable congestion on an affected facility.
Mean	The arithmetic average.
Median	The midpoint of data values. Half the values are above and half below the median.
Megawatt (MW)	A unit of power equal to 1,000 kilowatts.
Megawatt-day	One MW of energy flow or capacity for one day.
Megawatt hour (MWh)	One MWh is a megawatt produced or consumed for one hour.
Megawatt-year	One MW of energy flow or capacity for one calendar year.
Min gen	An emergency declaration for periods of light load.[1]
Monthly CCMs	The capacity credits cleared each month through the PJM Monthly Capacity Credit Markets (CCMs).
Multimonthly CCMs	The capacity credits cleared through PJM Multimonthly Capacity Credit Markets (CCMs).
Net excess (capacity)	The net of gross excess and gross deficiency, therefore the total PJM capacity resources in excess of the sum of load-serving entities' obligations.
Net exchange (capacity)	Capacity imports less exports.
Net interchange (energy)	Gross import volume less gross export volume in MWh.

2 See PJM Emergency Operations Manual, Section M13, Section 2, pp. 22-27.

North American Electric Reliability Council (NERC)	A voluntary organization of U.S. and Canadian utilities and power pools established to assure coordinated operation of the interconnected transmission systems.
Obligation	The sum of all load-serving entities' unforced capacity obligations as determined by summing the weather-adjusted summer coincident peak demands for the prior summer, netting out ALM credits, adding a reserve margin and adjusting for the system average forced outage rate.
Off peak	For the PJM Energy Market, off-peak periods are all NERC holidays (i.e., New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, Christmas Day) and weekend hours plus weekdays from the hour ending at midnight until the hour ending at 7:00 a.m.
On peak	For the PJM Energy Market, on-peak periods are weekdays, except NERC holidays (i.e., New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, Christmas Day) from the hour ending at 8:00 a.m. until the hour ending at 11:00 p.m.
Phase-in FTRs	FTRs directly allocated to eligible customers outside of the regularly scheduled FTR allocations when new control zones are integrated into PJM after the start of the current planning period. Phase-in FTRs remain in effect until the start of the next regularly scheduled FTR allocation.
PJM member	Any entity that has completed an application and satisfies the requirements of PJM to conduct business with the PJM Office of the Interconnection, including transmission owners, generating entities, load-serving entities and marketers.
PJM planning year	The calendar period from June 1 through May 31.
Price duration curve	A graphic representation of the percent of hours that a system's price was at or below a given level during the year.
Price-sensitive bid	Purchases of a defined MW level of energy only up to a specified LMP. Above that LMP, the load bid is zero.
Primary operating interfaces	Primary operating interfaces are typically defined by a

	cross section of transmission paths or single facilities which affect a wide geographic area. These interfaces are modeled as constraints whose operating limits are respected in performing dispatch operations.
Regional Transmission Expansion Planning Protocol	The process by which PJM recommends specific transmission facility enhancements and expansions based on reliability and economic criteria.
Selective catalytic reduction (SCR)	NOx reduction equipment usually installed on combined-cycle generators.
Self-scheduled generation	Units scheduled to run by their owners regardless of system dispatch signal. Self-scheduled units do not follow system dispatch signal and are not eligible to set LMP. Units can be submitted as a fixed block of MW that must be run, or as a minimum amount of MW that must run plus a dispatchable component above the minimum.
Shadow price	The constraint shadow price represents the incremental reduction in congestion cost achieved by relieving a constraint by 1 MW. The shadow price multiplied by the flow (in MW) on the constrained facility during each hour equals the hourly gross congestion cost for the constraint.
Sources and sinks	Sources are the origins or the injection end of a transmission transaction. Sinks are the destinations or the withdrawal end of a transaction.
Special protection scheme (SPS)	A load transfer relaying scheme intended to reduce the adverse post-contingency impact on a protected facility.
Spinning reserve	Reserve capability which is required in order to enable an area to restore its tie lines to the pre-contingency state within 10 minutes of a contingency that causes an imbalance between load and generation. During normal operation, these reserves must be provided by increasing energy output on electrically synchronized equipment or by reducing load on pumped storage hydroelectric facilities. During system restoration, customer load may be classified as spinning reserve.

Standard deviation	A measure of data variability around the mean.
System lambda	The cost to the PJM system of generating the next unit of output.
Temperature-humidity index (THI)	A temperature-humidity index has been developed by the U.S. National Weather Service (NWS). It gives a single, numerical value in the general range of 70 to 80, reflecting the outdoor atmospheric conditions of temperature and humidity as a measure of comfort (or discomfort) during warm weather. The temperature-humidity index, THI, is defined as follows: THI = T_d – (0.55 – 0.55RH) * (T_d - 58) where T_d is the dry-bulb temperature and RH is the percentage of relative humidity.
Unforced capacity	Installed capacity adjusted by forced outage rates.
Wheel-through	An energy transaction flowing through a transmission grid whose origination and destination are outside of the transmission grid.
Zone	See "Control zone" (above).

APPENDIX I - LIST OF ACRONYMS

ACE	Area control error
AECI	Associated Electric Cooperative Inc.
AECO	Atlantic City Electric Company
AEG	Alliant Energy Corporation
AEP	American Electric Power Company, Inc.
AGC	Automatic generation control
ALM	Active load management
AP	Allegheny Power Company
ARR	Auction Revenue Rights
ASA	Ancillary service areas
BGE	Baltimore Gas and Electric Company
BGS	Basic generation service
BME	Balancing market evaluation
C&I	Commercial and industrial customers
CCM	Capacity Credit Market
CC	Combined cycle
CDR	Capacity deficiency rate
CDTF	Cost development task force
CF	Coordinated flowgate under the Joint Operating Agreement between PJM and the Midwest Independent Transmission System Operator, Inc.
CILCO	Central Illinois Light Company
CIN	Cinergy Corporation

ComEd	The Commonwealth Edison Company
CPL	Carolina Power & Light Company
CPS	Control performance standard
CT	Combustion turbine
DAY	The Dayton Power & Light Company
DCS	Disturbance control standard
DLCO	Duquesne Light Company
DPL	Delmarva Power & Light Company
DPLN	Delmarva north
DPLS	Delmarva south
DSR	Demand-side response
DUK	Duke Energy Corp.
EDT	Eastern Daylight Time
ECAR	East Central Area Reliability Council
EDC	Electricity distribution company
EFORd	Equivalent demand forced outage rate
EHV	Extra high voltage
EKPC	East Kentucky Power Cooperative, Inc.
EPT	Eastern Prevailing Time
FE	FirstEnergy Corp.
FERC	The United States Federal Energy Regulatory Commission
FPPL	Forecast period peak load

FPR	Forecast pool requirement
FTR	Financial Transmission Rights
GCA	Generating control area
HHI	Herfindahl-Hirschman Index
HRSG	Heat recovery steam generator
ICAP	Installed capacity
IP	Illinois Power Company
IPL	Indianapolis Power & Light Company
IPP	Independent power producer
IRM	Installed reserve margin
IRR	Internal rate of return
ISO	Independent system operator
JCPL	Jersey Central Power & Light Company
JOA	PJM's Joint Operating Agreement with the Midwest Independent Transmission System Operator, Inc.
LCA	Load control area
LGEE	LG&E Energy, L.L.C.
LMP	Locational marginal price
LOC	Lost opportunity cost
LSE	Load-serving entity
LTE	Long-term emergency
MAIN	Mid-America Interconnected Network, Inc.
MAAC	Mid-Atlantic Area Council

MACRS	Modified accelerated cost recovery schedule
MAPP	Mid-Continent Area Power Pool
MC	The PJM Members Committee
MCP	Market-clearing price
MEC	MidAmerican Energy Company
MECS	Michigan Electric Coordinated System
Met-Ed	Metropolitan Edison Company
MEW	Western subarea of Metropolitan Edison Company
MICHFE	The pricing point for the Michigan Electric Coordinated System and First Energy control areas.
Midwest ISO	Midwest Independent Transmission System Operator, Inc.
MIL	Mandatory interruptible load
MP	Market participant
MMU	PJM Market Monitoring Unit
MUI	Market user interface
MW	Megawatt
MWh	Megawatt-hour
NERC	North American Electric Reliability Council
NICA	Northern Illinois Control Area
NIPSCO	Northern Indiana Public Service Company
NNL	Network and native load
NO_x	Nitrogen oxides
NYISO	New York Independent System Operator

OA	PJM Operating Agreement
OASIS	Open Access Same-Time Information System
OC	Opportunity cost
ODEC	Old Dominion Electric Cooperative
OEM	Original equipment manufacturer
OI	PJM Office of the Interconnection
Ontario IESO	Ontario Independent Electricity System Operator
OPL	Obligation peak load
OVEC	Ohio Valley Electric Corporation
PE	PECO zone
PECO	PECO Energy Company
PENELEC	Pennsylvania Electric Company
PEPCO	Pepco (formerly Potomac Electric Power Company)
PJM	PJM Interconnection
PJM/AEPNI	The interface between the American Electric Power Control Zone and Northern Illinois
PJM/AEPPJM	The interface between the American Electric Power Control Zone and PJM
PJM/AEPVP	The single interface pricing point formed in March 2003 from the combination of two previous interface pricing points: PJM/American Electric Power Company, Inc. and PJM/Dominion Resources, Inc.
PJM/AEPVPEXP	The export direction of the PJM/AEPVP interface pricing point
PJM/AEPVPIMP	The import direction of the PJM/AEPVP interface pricing point

PJM/ALTE	The interface between PJM and the eastern portion of the Alliant Energy Corporation's control area
PJM/ALTW	The interface between PJM and the western portion of the Alliant Energy Corporation's control area
PJM/AMRN	The interface between PJM and the Ameren Corporation's control area
PJM/CILC	The interface between PJM and the Central Illinois Light Company's control area
PJM/CPLE	The interface between PJM and the eastern portion of the Carolina Power & Light Company's control area
PJM/CPLW	The interface between PJM and the western portion of the Carolina Power & Light Company's control area
PJM/DLCO	The interface between PJM and the Duquesne Light Company's control area
PJM/DUK	The interface between PJM and the Duke Energy Corp.'s control area
PJM/FE	The interface between PJM and the FirstEnergy Corp.'s control area
PJM/IP	The interface between PJM and the Illinois Power Company's control area
PJM/Ontario IESO	PJM/Ontario IESO pricing point
PJM/MEC	The interface between PJM and MidAmerican Electric Company's control area
PJM/MECS	The interface between PJM and the Michigan Electric Coordinated System's control area
PJM/NIPS	The interface between PJM and the Northern Indiana Public Service Company's control area
PJM/NYIS	The interface between PJM and the New York Independent System Operator

PJM/OVEC	The interface between PJM and the Ohio Valley Electric Corporation's control area
PJM/TVA	The interface between PJM and the Tennessee Valley Authority's control area
PJM/VAP	The interface between PJM and the Dominion Virginia Power's control area
PJM/WEC	The interface between PJM and the Wisconsin Energy Corporation's control area
PLC	Peak load contributions
PNNE	PENELEC's northeastern subarea
PNNW	PENELEC's northwestern subarea
PPL	PPL Electric Utilities Corporation
PSEG	Public Service Electric and Gas Company
PSN	PSEG north
PSNC	PSEG northcentral
QIL	Qualified interruptible load
RAA	Reliability Assurance Agreement among Load-Serving Entities in the PJM Control Area
RECO	Rockland Electric Company zone
RMCP	Regulation market clearing price
RSI	Residual supply index
RTEPP	Regional Transmission Expansion Planning Protocol
RTO	Regional transmission organization
SCPA	Southcentral Pennsylvania subarea
SCR	Selective catalytic reduction

SEPJM	Southeastern PJM subarea
SFT	Simultaneous feasibility test
SMECO	Southern Maryland Electric Cooperative
SNJ	Southern New Jersey
SO_2	Sulfur dioxide
SPP	Southwest Power Pool, Inc.
SPREGO	Spinning and regulation market-clearing software
SPS	Special protection scheme
SRMCP	Spinning reserve market-clearing price
STE	Short-term emergency
THI	Temperature humidity index
TLR	Transmission loading relief
TVA	Tennessee Valley Authority
UGI	UGI Utilities, Inc.
VAP	Dominion Virginia Power
VOM	Variable operations and maintenance expense
WEC	Wisconsin Energy Corporation

ERRATA

If this sheet is bound with the report and not affixed to the errata page, then relevant changes are reflected in the Report. Otherwise, the corrections described below can be found in the online version currently available at http://www.pjm.com/markets/market-monitor/som.html.

Page 44- Figure 1-6 and associated text has been revised

Please address comments or questions to: bowrij@pjm.com.