APPENDIX H – CALCULATING LOCATIONAL MARGINAL PRICE

In order to understand the relevance of various measures of locational marginal price (LMP), it is important to understand how average LMPs are calculated across time and across buses. This appendix explains how PJM calculates average LMP and load-weighted, average LMP for the system, for a zone and, by extension, for any aggregation of buses, for an hour, for a day and for a year.[1] This appendix also explains how the Market Monitoring Unit (MMU) calculates average LMP for states, consistent with the PJM method for other aggregates.

Real-Time Hourly Integrated LMP and Real-Time Hourly Integrated Load

In PJM a real-time LMP is calculated at every bus for every five-minute interval.

The system real-time, five-minute, average LMP is the load-weighted, average LMP for that five-minute interval, calculated using the five-minute LMP at each load bus and the corresponding five-minute load at each load bus in the system. The sum of the product of the five-minute LMP and the five-minute load at each bus, divided by the sum of the five-minute loads across the buses equals the system load-weighted, average LMP for that five-minute interval.

In PJM, the real-time hourly LMP at a bus is equal to the simple average of each hour's 12 five-minute interval LMPs at that bus. This is termed the hourly integrated LMP at the bus. The hourly load at a bus is also calculated as the simple average of each hour's 12 five-minute interval loads at that bus. This is termed the hourly integrated load at the bus. The hourly values for LMP and load are the basis of PJM's settlement calculations.

Day-Ahead Hourly LMP and Day-Ahead Hourly Load

The day-ahead LMP is calculated at every bus for every hour from the day-ahead dispatch required to meet estimated nodal loads derived from the distribution factors plus nodal load from decrement bids (DECs) and price-sensitive load and nodal supply from generation offers and increment offers (INCs). The result is a full set of day-ahead nodal LMPs and cleared, nodal loads.

This measure of nodal, day-ahead load is used in system load-weighted, average LMP calculations. This is termed nodal, total day-ahead load here. Zonal, day-ahead hourly aggregate load is assigned to buses in the relevant zone using zonal distribution factors.

Day-ahead zonal distribution factors are calculated from historical real-time, bus-level load distributions that were in effect at 8 AM seven days prior. The use of load data from a period seven days prior to the DA price calculations provides a week day match but the lack of adjustment for other factors that affect bus-specific loads, including temperature, introduces a potentially significant inaccuracy in the load data used to clear the day-ahead market. This would be an issue to the extent that weather or other factors changes the relative size of nodal loads.

1 The unweighted, average LMP is also referred to as the simple average LMP.

Zonal, day-ahead, load-weighted LMP is calculated from nodal day-ahead LMP using zonal distribution factors as the load weights. This measure of load weights excludes bus specific loads, such as DECs, that clear in the day-ahead market. The exclusion of bus specific loads from the calculation of day ahead load weighted LMP means that the zonal day-ahead load weighted prices reported by PJM do not reflect the load weighted price paid by all load in a zone, but instead reflect only the price paid by the load that settles at the day ahead hourly zonal price.

Factor distributed load, used in the calculation of state load weighted average LMP, is calculated by multiplying day-ahead zonal hourly load (fixed plus price-sensitive load only) by day-ahead distribution factors. The factor distributed load calculation provides bus specific load weights, derived directly from the day ahead zonal distribution factors, which are used to calculate day-ahead load and load weighted average LMP for states with load buses in multiple zones or parts of zones. This methodology is used because it results in weighted LMPs that are consistent with how zonal factor weighted prices are determined by PJM. This means that where the zone buses are the same as state buses, the result will be the same. For example, the state of Maryland contains buses from the AP, BGE, DPL and Pepco zones, but the areas encompassed by these aggregates, with the exception of BGE, extend beyond the borders of the state. AP, for example, extends past the western portion of Maryland into Pennsylvania, Ohio, West Virginia and Virginia. To provide Maryland specific results for load and LMP, a Maryland aggregate is calculated using only those AP, BGE, DPL and Pepco load buses that are physically within the geographic boundaries of the state of Maryland.

Load-Weighted, Average LMP

Real Time

The system real-time, load-weighted, average LMP for an hour is equal to the sum of the product of the hourly integrated bus LMPs for each load bus and the hourly integrated load for each load bus, for the hour, divided by the sum of the hourly integrated bus loads for the hour.

The zonal real-time, load-weighted, average LMP for an hour is equal to the sum of the product of the hourly integrated bus LMPs for each load bus in a zone and the hourly integrated load for each load bus in that zone, divided by the sum of the real-time hourly integrated loads for each load bus in that same zone.

The real-time, load-weighted, average LMP for an hour for a state is equal to the sum of the product of the hourly integrated bus LMPs for each load bus in a state and the hourly integrated load for each load bus in that state, divided by the sum of the real-time hourly integrated loads for each load bus in that state.

The system real-time, load-weighted, average LMP for a day is equal to the product of the hourly integrated LMPs for each load bus and the hourly integrated load for each load bus, for each hour, summed over every hour of the day, divided by the sum of the hourly integrated bus loads for the system for the day.

The zonal real-time, load-weighted, average LMP for a day is equal to the product of each of the hourly integrated LMPs for each load bus in a zone and the hourly integrated load for each load bus in that zone, for each hour, summed over every hour of the day, divided by the sum of the hourly integrated bus loads at each load bus in that zone for the day.

The real-time, load-weighted, average LMP for a day for a state is equal to the product of each of the hourly integrated LMPs for each load bus in a state and the hourly integrated load for each load bus in that state, for each hour, summed over every hour of the day, divided by the sum of the hourly integrated bus loads at each load bus in that state for the day.

The system real-time, load-weighted, average LMP for a year is equal to the product of the hourly integrated LMPs and hourly integrated load for each load bus, summed across every hour of the year, divided by the sum of the hourly integrated bus loads at each load bus in the system for each hour in the year.

The zonal real-time load-weighted, average LMP for a year is equal to the product of each of the hourly integrated bus LMPs and hourly integrated load for each load bus in a zone, summed across every hour of the year, divided by the sum of the hourly integrated bus loads at each load bus in that zone for each hour in the year.

The real-time load-weighted, average LMP for a year for a state is equal to the product of each of the hourly integrated bus LMPs and hourly integrated load for each load bus in a state, summed across every hour of the year, divided by the sum of the hourly integrated bus loads at each load bus in that state for each hour in the year.

Day Ahead

The system day-ahead, load-weighted, average LMP for an hour is equal to the sum of the product of the hourly LMP at each load bus and the corresponding nodal, total day-ahead hourly load at each load bus in the system, divided by the sum of the nodal, total day-ahead hourly loads across the buses.

The zonal day-ahead, load-weighted, average LMP for an hour is equal to the sum of the product of the hourly bus LMPs for each load bus in a zone and the hourly estimated load distribution factors for each load bus in that zone. The zonal day-ahead, load-weighted, average LMP does not use the full nodal, total day-ahead hourly loads used in the other calculations of day-ahead average LMP.

The day-ahead, load-weighted, average LMP for an hour for a state is equal to the sum of the product of the hourly bus LMPs for each load bus in a state and the hourly factor distributed load, from each contributing zone, for each load bus in that state. The state specific day-ahead, load-weighted, average LMP does not use the full nodal, total day-ahead hourly loads used in the other calculations of day-ahead average LMP.

The system day-ahead, load-weighted, average LMP for a day is equal to the product of the hourly day-ahead LMPs for each load bus and the nodal, total hourly day-ahead load for each load bus, for each hour, summed over every hour of the day, divided by the sum of the nodal, total hourly day-ahead loads for the system for the day.

The zonal day-ahead, load-weighted, average LMP for a day is equal to the product of each of the hourly day-ahead LMPs for each load bus in a zone and the hourly estimated load distribution factors for each load bus in that zone and the hourly day-ahead load for the zone, summed over every hour of the day, and divided by the corresponding estimated total zonal load for the day. The zonal day-ahead, load-weighted, average LMP does not use the full nodal, total day-ahead hourly loads used in the other calculations of day-ahead average LMP.

The day-ahead, load-weighted, average LMP for a day for a state is equal to the product of each of the hourly day-ahead LMPs for each load bus in a state and the hourly factor distributed load, from each contributing zone, for each load bus in that state, summed over every hour of the day, and divided by the corresponding estimated total hourly factor distributed load for the day. The zonal day-ahead, load-weighted, average LMP does not use the full nodal, total day-ahead hourly loads used in the other calculations of day-ahead average LMP.

The system day-ahead, load-weighted, average LMP for a year is equal to the product of the hourly LMPs and nodal, total hourly load for each load bus, summed across every hour of the year, divided by the sum of the nodal, total hourly bus loads at each load bus in the system for each hour in the year.

The zonal day-ahead, load-weighted, average LMP for a year is equal to the product of each of the hourly LMPs for each load bus in a zone and the hourly estimated load distribution factors for each load bus in that zone and the hourly day-ahead load for the zone, summed over every hour of the year, and divided by the total estimated zonal load for the year. The zonal day-ahead, load-weighted, average LMP does not use the full nodal, total day-ahead hourly loads used in the other calculations of day-ahead average LMP.

The day-ahead, load-weighted, average LMP for a year for a state is equal to the product of each of the hourly LMPs for each load bus in a zone and the hourly factor distributed load, from each contributing zone, for each load bus in that state, summed over every hour of the year, and divided by the corresponding estimated total hourly factor distributed load for the year. The zonal day-ahead, load-weighted, average LMP does not use the full nodal, total day-ahead hourly loads used in the other calculations of day-ahead average LMP.

Equation H-1 LMP calculations

	i = 5-minute interval	h = 12 intervals = hour i = 1..12	d = 24 hours = day h = 1..24	y = 365 days = 8,760 hours = year d = 1..365
Bus average	LMP_{bi}	$LMP_{bh} = \frac{\sum_{i=1}^{12} LMP_{bi}}{12}$	$LMP_{bd} = \frac{\sum_{h=1}^{24} LMP_{bh}}{24}$	$LMP_{by} = \frac{\sum_{h=1}^{8760} LMP_{bh}}{8760}$
Bus load-weighted average			$lwLMP_{bd} = \frac{\sum_{h=1}^{24} (LMP_{bh} \bullet Load_{bh})}{\sum_{h=1}^{24} Load_{bh}}$	$lwLMP_{by} = \frac{\sum_{h=1}^{8760} (LMP_{bh} \bullet Load_{bh})}{\sum_{h=1}^{8760} Load_{bh}}$
System average	$LMP_{si} = \frac{\sum_{b=1}^{B} LMP_{bi}}{B}$	$LMP_{sh} = \frac{\sum_{b=1}^{B} LMP_{bh}}{B}$	$LMP_{sd} = \frac{\sum_{h=1}^{24} \frac{\sum_{b=1}^{B} (LMP_{bh} \bullet Load_{bh})}{\sum_{b=1}^{B} Load_{bh}}}{24}$	$LMP_{sy} = \frac{\sum_{h=1}^{8760} \frac{\sum_{b=1}^{B} (LMP_{bh} \bullet Load_{bh})}{\sum_{b=1}^{B} Load_{bh}}}{8760}$
System load-weighted average	$lwLMP_{si} = \frac{\sum_{b=1}^{B} (LMP_{bi} \bullet Load_{bi})}{\sum_{b=1}^{B} Load_{bi}}$	$lwLMP_{sh} = \frac{\sum_{b=1}^{B} (LMP_{bh} \bullet Load_{bh})}{\sum_{b=1}^{B} Load_{bh}}$	$lwLMP_{sd} = \frac{\sum_{h=1}^{24} \sum_{b=1}^{B} (LMP_{bh} \bullet Load_{bh})}{\sum_{h=1}^{24} \sum_{b=1}^{B} Load_{bh}}$	$lwLMP_{sy} = \frac{\sum_{h=1}^{8760} \sum_{b=1}^{B} (LMP_{bh} \bullet Load_{bh})}{\sum_{h=1}^{8760} \sum_{b=1}^{B} Load_{bh}}$

APPENDIX I – LOAD DEFINITIONS

PJM measures load in a number of ways. The Market Monitoring Unit (MMU) makes use of two basic measures of load in its analysis of the PJM market: peak load and accounting load. In the *2009 State of the Market Report for PJM*, both measures of load are used, as appropriate for the specific analysis. The measures of load and their applications changed after PJM's June 1, 2007, implementation of marginal losses.

Peak Load

PJM uses eMTR data for both peak loads and as the basis for accounting loads. eMTR data is supplied by PJM electricity distribution companies (EDCs) and generators and is based on the metered MWh values of tie lines and the metered values of generation MWh. For PJM Western Region and Southern Region EDCs (ComEd, AEP, DAY, DLCO, AP and Dominion), eMTR load values implicitly include local, EHV (extra-high-voltage) and non-EHV losses. eMTR load values for PJM Mid-Atlantic Region EDCs implicitly include local and non-EHV losses plus an explicit allocation of metered Mid-Atlantic Region EHV losses. PJM uses this eMTR load data to measure peak loads. This measure of load provides the total amount of generation output and net energy imports required to meet the peak demand on the system. It is not strictly a measure of load, but rather a measure of the output and imports necessary to meet load.

Accounting Load

PJM uses eMTR load data, excluding losses, as accounting load in the settlement process. Prior to June 1, 2007, accounting load for all EDCs was equal to eMTR load and thus included losses. Since the implementation of marginal losses on June 1, 2007, accounting load without losses is calculated by subtracting State Estimator losses from eMTR load and allocating the net amount to load buses based on State Estimator loads. Since June 1, 2007, accounting load without losses has represented the actual retail customer load and is referred to here as accounting load.

Accounting load is used in the *2009 State of the Market Report for PJM* to measure daily, monthly and annual load. Accounting load is also used in the *2009 State of the Market Report for PJM* to weight LMP in load-weighted LMP calculations. Prior to June 1, 2007, accounting load included losses and after June 1 accounting load excludes losses. Prior to June 1, 2007, LMP did not include losses. After June 1, 2007, LMP includes losses.

APPENDIX J – MARGINAL LOSSES

On June 1, 2007, PJM revised its methodology for determining transmission losses from average losses to nodal, marginal losses. Marginal loss pricing is based on the incremental losses that result from an increase in output. Marginal loss pricing is designed to permit more efficient system dispatch and decreased total production cost.

Under the new methodology, PJM's locational marginal price (LMP) at a bus *i* is comprised of three distinct components: system marginal price (SMP), marginal losses component of LMP at bus *i* (L_i) and the congestion component of LMP at bus *i* ($CLMP_i$).

Equation J-1 shows the components of LMP at bus *i*.

Equation J-1 LMP components

$$LMP_i = SMP + L_i + CLMP_i$$

SMP is calculated at the distributed load reference bus, where the loss and CLMP contribution to LMP are zero. The LMP at bus *i* is comprised of losses and congestion effects, either positive or negative, that are determined by the bus's location on the system relative to the SMP at the load weighted reference bus.

Total, Average and Marginal Losses

Total transmission losses are equal the product of the square of the current flowing across the line (*I*) and the resistance of the line (*R*). The materials constituting the conductors and other elements of the transmission system exhibit a characteristic impedance to the flow of power. Total transmission losses over a line can also be expressed as the product of the resistance of the line (*R*) times the square of the power consumed by the load (*P*), divided by the square of the voltage (*V*).[1] While this relationship differs somewhat in an alternating current (AC) as compared to a direct current (DC) system, the magnitude of losses can be approximated by the equation:

Equation J-2 Total transmission losses

Total Losses = $I^2 \cdot R = (P^2 \cdot R) / V^2$,

Defining $a = R / V^2$ and substituting into Equation J-2 results in:

Equation J-3 Total transmission losses

Total Losses = $a \cdot P^2$.

Average transmission losses per MW from a given power flow *P* across a transmission element are:

1 Equation J-2 incorporates the substitution of the relationship *I=P/V*, derived from Ohm's Law, for the variable *I*.

Equation J-4 Average transmission losses

$$\text{Average Losses} = \left(a \cdot P^2 / P\right) = a \cdot P \,.$$

Marginal transmission losses are the incremental losses resulting from an increase in power flow P across the transmission element and are equal to the first derivative of total losses with respect to power flow P:

Equation J-5 Marginal losses

$$\text{Marginal Losses} = \frac{d}{dP}\left(a \cdot P^2\right) = 2 \cdot a \cdot P \,.$$

For a given power flow P, the marginal losses for an increase in P are, therefore, equal to twice the average losses for the associated total flow P.

Effect of Marginal Losses on LMP

The following equations illustrate the effect of marginal losses on least cost dispatch. In this simple example, the least cost dispatch problem involves meeting system load and the losses associated with serving that load.

Equation J-6 defines the total cost of generation (C_T), which is a function of generator output (P) of units i though N.

Equation J-6 Total cost of generation

$$C_T = \sum_{i=1}^{N} \left[C_i(P_i)\right]$$

Equation J-7 is the power balance constraint, where total injections ($\sum_i^N P_i$) must equal total withdrawals (P_{load}) plus total losses (P_{loss}), where losses are a function of ($\sum_i^N P_i$).

Equation J-7 Power Balance Constraint

$$P_{load} + P_{loss}\left(\sum_{i=1}^{N} P_i\right) = \sum_{i=1}^{N} P_i$$

Together, equation Equation J-6 and Equation J-7 form a system of equations which can be represented by a Lagrangian (ζ), as defined in Equation J-8.

Equation J-8 System

$$\zeta(P_i) = \sum_{i=1}^{N} C_i(P_i) + \lambda_i \bullet (P_{load} + P_{loss}(\sum_i^N P_i) - \sum_{i=1}^{N} P_i)$$

Optimizing Equation J-8 for $P_{i...n}$ results in Equation J-9 and Equation J-7:

Equation J-9 Lambda

$$\frac{dC}{dP_i} \bullet \frac{1}{(1-\frac{dP_{loss}}{dP_i})} = \lambda_i$$

Equation J-10 Power Balance Constraint (from above)

$$P_{load} + P_{loss}\left(\sum_{i=1}^{N} P_i\right) = \sum_{i=1}^{N} P_i$$

Note, that Equation J-9 shows that the optimal dispatch of each generator *i* must account for losses associated with using that unit to meet load. This measure of losses is the marginal loss penalty factor (Pf_f) for incremental power from generator *i* to serve system load:

Equation J-11 Penalty factor

$$Pf_i = \frac{1}{\left(1-\frac{\partial P_{loss}}{\partial P_i}\right)}.$$

The incremental cost of using output from generator *i* to meet load includes incremental losses.[2]

The term $\frac{\partial P_{loss}}{\partial P_i}$ is called the loss factor and represents the change in system losses for a change in output from generator *i* to meet load.

If an increase in power from generator *i* results in an incremental increase in losses, then the loss factor is positive:

$$0 < \frac{\partial P_{loss}}{\partial P_i} < 1,$$

and the resultant penalty factor at bus_i would be greater than one:

$$Pf_i = \frac{1}{\left(1-\frac{\partial P_{loss}}{\partial P_i}\right)} > 1.$$

Conversely, if an increase in power results in a decrease in losses, then the loss factor is negative:

$$-1 < \frac{\partial P_{loss}}{\partial P_i} < 0,$$

and the resultant penalty factor at bus *i* would be less than one: $Pf_i = \frac{1}{\left(1-\frac{\partial P_{loss}}{\partial P_i}\right)} < 1$.

2 Note, as presented here, the marginal effect is on total losses, not losses at any particular load bus.

The unit offer curve of a generator is multiplied by the respective penalty factor for serving the load. (See Equation J-11) To the system operator, seeking to minimize the costs of serving a given level of load, the existence of losses modifies the relative costs of output from the unit relative to the case where losses are not accounted for. If the relevant penalty factor is greater than one, system losses would be made greater by increasing the output of that generator to serve load, and the unit offer curve, from the system operator perspective, would be shifted upward relative to the case where losses were not accounted for. Similarly, if the penalty factor associated with generator i delivering power to load is less than one, system losses associated with serving system load would be reduced by increasing the output of generator *i* , and the unit offer curve would shift downward relative to the case where losses are not accounted for.

These marginal loss related adjustments in relative costs will affect the optimal dispatch, and the resulting LMPs, for any given level of load relative to the case where marginal losses are not accounted for. LMPs at specific load buses will reflect the fact that marginal generators must produce more (or less) energy due to losses to serve that bus than is needed to serve the load weighted reference bus. The LMP at any bus is a function of the SMP, losses and congestion. Relative to the system marginal price (SMP) at the load weighted reference bus, the loss factor can be either positive or negative.

Loss Revenue Surplus

As demonstrated in Equation J-5, revenues resulting from marginal losses are approximately twice those collected from average losses. As demonstrated in Equation J-2, losses are equal to the square of the power, *P.* As such, two loads of equal size at the same location, served simultaneously, result in losses four times greater than the losses incurred in serving either of them separately. By utilizing the penalty factor in the dispatch, losses are paid based on marginal losses rather than based on average losses. Other than the effect on the optimal dispatch point, LMP at the marginal generator bus, and therefore the payment to the generator, is not affected. By paying for losses based on marginal instead of average losses at the load bus, a revenue over collection occurs. Using the example of two loads, of equal size at the same location, being served simultaneously, the marginal losses associated with the combined effect of the loads are greater than the sum of the losses incurred by each load separately, thus resulting in an over collection.

Properly accounting for marginal losses allows for an optimal, least cost solution to the system of equations that make up the market to serve load. Over collection is a direct outcome of marginal cost pricing and not a cause for concern. Prices set on this basis reflect the true incremental cost of serving load at any bus, and provide efficient incremental resource signals. Of concern under these circumstances is what is done with the over collection and how it is distributed among the market participants. These disbursements should be provided to the market participants that pay for the marginal losses in their energy charges, in this case the loads. To maintain an efficient price signal, any reallocation of the excess revenues must not interfere with the price signal at the margin. The solution to this problem generally takes the form of lump sum payments to market participants. The next issue is how to distribute the payments among the loads. To the extent that the causality of total marginal losses related costs are not generally directly attributable to specific load serving entities, the actual allocation methodology used to distribute the lump sum payments, while important from a policy perspective, is more a question of equity than market outcome efficiency. Under these circumstances, where there are common costs attributable to providing a service to a number of parties, it is general accepted practice to allocate the common costs, or benefits, to participants in proportion to their contribution to total load. This is the approach adopted by PJM. Under PJM's tariff, excess total loss related revenues are allocated to transmission users based on load plus export ratio shares:

Equation J-12 Excess loss revenue allocation

$$\text{Loss Credit} = (\text{Total Loss Surplus}) + \left(\frac{\text{Customer total MWh delivered to load } + \text{ exports}}{\text{Total PJM MWh delivered to load } + \text{ exports}}\right).$$

APPENDIX K – CALCULATION AND USE OF GENERATOR SENSITIVITY/ UNIT PARTICIPATION FACTORS

Sensitivity factors define the impact of each marginal unit on locational marginal price (LMP) at every bus on the system. The availability of sensitivity factor data permits the refinement of analyses in areas where the goal is to calculate the impact of unit characteristics or behavior on LMP.[1] These factors include the impact on LMP of the cost of fuel by type, the cost of emissions allowances by type, frequently mitigated unit adders and unit markup by unit characteristics.[2]

Generator sensitivity factors, or unit participation factors (UPFs), are calculated within the least-cost, security-constrained optimization program. For every five-minute system solution, UPFs describe the incremental amount of output that would have to be provided by each of the current set of marginal units to meet the next increment of load at a specified bus while maintaining total system energy balance. A UPF is calculated from each marginal unit to each load bus for every five-minute interval. In the absence of marginal losses, the UPFs associated with the set of marginal units in any given interval, for a particular load bus, always sum to 1.0. UPFs can be either positive or negative. A negative UPF for a unit with respect to a specific load bus indicates that the unit would have to be backed down for the system to meet the incremental load at the load bus.

Within the security-constrained, least-cost dispatch solution for an interval, during which the LMP at the marginal unit's bus equals the marginal unit's offer, consistent with its output level, LMP at each load bus is equal to each marginal unit's offer price, multiplied by its UPF, relative to that load bus. In some cases, the bus price for the marginal unit may not equal the calculated price based on the offer curve of the marginal unit. These differences are the result of the LPA marginal unit offer being overridden with its UDS LMP or ex-ante dispatch rate. When overridden, the LPA marginal unit's current offer is replaced by the UDS LMP and this sets the price. The UDS LMP does not reflect the LPA marginal unit's offer curve and does not represent the offer behavior of the marginal units in the LPA whose offers are overridden. The UDS LMP is a result of the marginal units in UDS and reflects the offer curve and behavior of these units. Any difference between the price based on the offer curve and the actual bus price when no override occurs is categorized as "dispatch differential." When an override occurs and the price difference cannot be explained with the UDS solution, the difference is categorized as "UDS override differential." In addition, final LMPs calculated using UPFs may differ slightly from PJM's posted LMPs as a result of rounding and missing data. Such differentials are identified as not available (NA).

Table K-1 shows the relationship between marginal generator offers and the LMP at a specific load bus X in a given five-minute interval.

Table K-1 LMP at bus X

Generator	UPF Bus X	Offer	Generator Contribution to LMP at X	Generator Contribution to LMP at X (Percentage)
A	0.5	$200.00	$100.00	85%
B	0.4	$40.00	$16.00	14%
C	0.1	$10.00	$1.00	1%
			LMP at X	
			$117.00	100%

1 The PJM Market Monitoring Unit (MMU) identified applications for sensitivity factors and began to save sensitivity factors in 2006.

2 Before the *2006 State of the Market Report*, state of the market reports had shown the impact of each marginal unit on load and on LMP based on engineering estimates whenever there were multiple marginal units.

Table K-1 shows three hypothetical, marginal generators at three different buses (A, B and C); each affects LMP at load bus X. Each generator's effect on LMP at X is measured by the UPF of that unit with respect to X. The UPF for generator A is 0.5 relative to load bus X, meaning that 50 percent of marginal Unit A's offer price contributes directly to the LMP at X. Since A has an offer price of $200, generator A contributes $100, or UPF times the offer, to the LMP at load bus X. The UPFs from all the marginal units to the load bus must sum to 1.0, so that the marginal units explain 100 percent of the load bus LMP. Generators B and C have UPFs of 0.4 and 0.1, respectively, and offer prices of $40 and $10, respectively, and therefore contribute $16 and $1, respectively, to the LMP at X. Together, the marginal units' offers multiplied by their UPFs with respect to load bus X explain the interval LMP at the load bus.

Hourly Integrated LMP Using UPF

Table K-1 describes the relationship between LMP and UPFs for a five-minute interval. Since PJM charges loads and credits generators on the basis of hourly integrated LMP, the relationship among marginal unit offers, UPFs and the hourly integrated LMP must be specified.

The relevant variables and notation are defined as follows:

h = hour,

i = five-minute interval,

t = year, where *t* designates the current year and *t*-1 designates the previous year,

b = a specified load bus, where *b* ranges from 1 to *B*,

g = a specified marginal generator, where *g* ranges from 1 to *G*, and

L = interval-specific load.

The hourly integrated load at a bus is the simple average of the 12 interval loads at a bus in a given hour:

Equation K-1 Hourly integrated load at a bus

$$Load_{bh} = \frac{\sum_{i=1}^{12} L_{bi}}{12}.$$

Load bus *LMP* is determined on a five-minute basis and is a function of marginal unit offers and *UPF*s in that interval:

Equation K-2 Load bus LMP

$$LMP_{bi} = \sum_{g=1}^{G} \left(Offer_{gi} \bullet UPF_{gbi} \right).$$

The hourly integrated *LMP* at a bus is the simple average of the 12 interval LMPs at a bus in a given hour:

Equation K-3 Hourly integrated LMP at a bus

$$LMP_{bh} = \frac{\sum_{i=1}^{12} LMP_{bi}}{12}.$$

Total cost (*TC*) of the system in the hour is equal to the product of the hourly integrated LMP and the hourly integrated load at each bus summed across all buses in the hour:

Equation K-4 Hourly total system cost

$$TC_h = \sum_{b=1}^{B} \left(LMP_{bh} \bullet Load_{bh}\right).$$

System load-weighted LMP for the hour ($LMPSYS_h$) is equal to the total hourly system cost (*TC*) divided by the sum of a bus's simple 12 interval average loads in the hour:

Equation K-5 Hourly load-weighted LMP

$$LMPSYS_h = \frac{TC_h}{\sum_{b=1}^{B} Load_{bh}}.$$

The system annual, load-weighted, average (S*LW*) LMP for the year is:

Equation K-6 System annual, load-weighted, average LMP

$$Annual\_SLW\_LMP = \sum_{h=1}^{8760} \frac{TC_h}{\sum_{b=1}^{B} Load_{bh}}.$$

Hourly Integrated Markup Using UPFs

Markup is defined as the difference between the price from the price-based offer curve and the cost from the cost-based offer curve at the operating point of a specific marginal unit. UPFs can be used to calculate the impact of marginal unit markup behavior on the LMP at any individual load bus and of the LMP at any aggregation of load buses including the system LMP. The resultant markup component of LMP is a measure of market power, a market performance metric. The markup component of LMP is based on the markup of the actual marginal units and is not based on a redispatch of the system using cost-based offers.

To determine the impact of marginal unit markup behavior on system LMP on an hourly integrated basis, the following steps are required.

Total cost (*TC*) of the system in the hour is equal to the product of the average LMP and the average load at each bus summed across all buses in the hour which, using the definitions above, can be expressed in terms of marginal unit offers and UPFs:

Equation K-7 UPF-based system hourly total cost

$$TC_h = \sum_{b=1}^{B}\left(LMP_{bh} \bullet Load_{bh}\right) = \sum_{b=1}^{B}\left[Load_{bh} \bullet \frac{\sum_{i=1}^{12}\sum_{g=1}^{G}\left(Offer_{gi} \bullet UPF_{gbi}\right)}{12}\right].$$

System load-weighted LMP for the hour is equal to total hourly system cost divided by the sum of the bus's simple 12 interval average loads in the hour:

Equation K-8 System load-weighted LMP

$$LMPSYS_h = \frac{TC_h}{\sum_{b=1}^{B} Load_{bh}} = \frac{\sum_{b=1}^{B}\left[Load_{bh} \bullet \frac{\sum_{i=1}^{12}\sum_{g=1}^{G}\left(Offer_{gi} \bullet UPF_{gbi}\right)}{12}\right]}{\sum_{b=1}^{B} Load_{bh}}.$$

Holding dispatch and marginal units constant, the system, hourly load-weighted LMP based on cost offers of the marginal units, shown in Equation K-9, is found by substituting the marginal unit cost offers into Equation K-8**:**

Equation K-9 Cost-based offer system, hourly load-weighted LMP

$$LMPSYSCost_h = \frac{TC_h}{\sum_{b=1}^{B} Load_{bh}} = \frac{\sum_{b=1}^{B}\left[Load_{bh} \bullet \frac{\sum_{i=1}^{12}\sum_{g=1}^{G}\left(CostOffer_{gi} \bullet UPF_{gbi}\right)}{12}\right]}{\sum_{b=1}^{B} Load_{bh}}.$$

The contribution of the markup by marginal units to system LMP for the hour is shown in Equation K-10 below:

Equation K-10 Impact of marginal unit markup on LMP

$$MarkUp_h = LMPSYS_h - LMPSYSCost_h.$$

UPF–Weighted, Marginal Unit Markup

The price-cost markup index for a marginal unit provides a measure of market power based on the behavior of a single unit of an individual generator:

Equation K-11 Price-cost markup index

$$MarkUp_{gi} = \frac{Offer_{gi} - CostOffer_{gi}}{Offer_{gi}}.$$

The UPF load-weighted, marginal unit markup (measure of unit behavior) provides a measure of market power for a given hour for the system or any aggregation of load buses. This measure of system performance equals the weighted-average markup index for all marginal units, which is a measure of unit behavior:

Equation K-12 UPF load-weighted, marginal unit markup

$$lwMarkUp_h = \frac{\sum_{b=1}^{B}\left[\frac{\sum_{i=1}^{12}\sum_{g=1}^{G}\left(MarkUp_{gi} \bullet UPF_{gbi}\right)}{12} \bullet Load_{bh}\right]}{\sum_{b=1}^{B} Load_{bh}}.$$

Hourly Integrated Historical, Cost-Adjusted, Load-Weighted LMP Using UPFs

UPFs can be used to calculate historical, cost-adjusted, load-weighted LMP for a specific time period. This method is used to disaggregate the various components of LMP, including all the separate components of unit marginal cost and unit markup, and to calculate the contributions of each component to system LMP.

The extent to which fuel cost, emission allowance cost, variable operation and maintenance cost (VOM) and markup affect the offers of marginal units depends on the share of the offer that each component represents. The percentage of a unit's offer that is based on each of the components is given as the following:

Fuel:	$\%Fuel_{gi}$
SO_2:	$\%SO_{2\,gi}$
NO_x:	$\%NO_{x\,gi}$
VOM:	$\%VOM_{gi}$
Markup:	$\%MarkUp_{gi}$

The proportion of specific components of unit offers is calculated on an interval and on a unit-specific basis. Cost components are determined for each marginal unit for the relevant time periods:

Delivered fuel cost per MWh: FC_{gt}.

Sulfur dioxide, emission-related cost per MWh: $SO_{2\,gt}$.

Nitrogen oxide, emission-related cost per MWh: $NO_{x\,gt}$.

Fuel costs (*FC)* are specific to the unit's location, the unit's fuel type and the time period in question. For example:

FC_{gt} = Avg *FC* in specified "Current Year's Period" (e.g., April 1, 2008); and

FC_{gt-1} = Avg *FC* in specified "Previous Year's Period" (e.g., April 1, 2007).

Fuel-Cost-Adjusted LMP

The portion of a marginal generator's offer that is related to fuel costs for a specified period is adjusted to reflect the previous period's fuel costs. Subtracting the proportional fuel-cost adjustment from the marginal generator's interval-specific offer provides the fuel-cost-adjusted offer (*FCA)*:

Equation K-13 Fuel-cost-adjusted offer

$$FCAOffer_{gi} = Offer_{gi} \bullet \left[1 - \%Fuel_{gi} \bullet \left(\frac{FC_{gt} - FC_{gt-1}}{FC_{gt}} \right) \right].$$

Using $FCAOffer_{gi}$ for all marginal units in place of the unadjusted offers ($offer_{gi}$) in Equation K-8 (i.e., the system load-weighted LMP equation), results in the hourly fuel-cost-adjusted, load-weighted LMP:

Equation K-14 Fuel-cost-adjusted, load-weighted LMP

$$LWFCAsysLMP_h = \frac{TCFCA_h}{\sum_{b=1}^{B} Load_{bh}} = \frac{\sum_{b=1}^{B} \left[Load_{bh} \bullet \frac{\sum_{i=1}^{12} \sum_{g=1}^{G} \left(FCAOffer_{gi} \bullet UPF_{gbi} \right)}{12} \right]}{\sum_{b=1}^{B} Load_{bh}}.$$

The systemwide annual, fuel-cost-adjusted, load-weighted (*SFCALW*) LMP for the year is given by the following equation:

Equation K-15 Systemwide annual, fuel-cost-adjusted, load-weighted LMP

$$Annual\_SFCALW\_LMP = \sum_{h=1}^{8760} \frac{TCFCA_h}{\sum_{b=1}^{B} Load_{bh}}.$$

Cost-Adjusted LMP

Summing the unit's specific historical, cost-adjusted component effects and subtracting that sum from the unit's unadjusted offer provides the historical, cost-adjusted offer of the unit (*HCAOffer*):

Equation K-16 Unit historical, cost-adjusted offer

$$HCAOffer_{gi} = Offer_{gi} \bullet \left[1 - \%Fuel_{gi} \bullet \left(\frac{FC_{gt} - FC_{gt-1}}{FC_{gt}}\right) - \%NOx_{gi} \bullet \left(\frac{NOx_{gt} - NOx_{gt-1}}{NOx_{gt}}\right) - \%SO2_{gi} \bullet \left(\frac{SO2_{gt} - SO2_{gt-1}}{SO2_{gt}}\right)\right].$$

Using each unit's $HCAOffer_{gi}$ in place of its unadjusted offers ($offer_{gi}$) in Equation K-8 (i.e., the system load-weighted LMP equation) results in the following historical, cost-adjusted, load-weighted LMP for the hour in question:

Equation K-17 Unit historical, cost-adjusted, load-weighted LMP

$$LWHCAsysLMP_h = \frac{TCHCA_h}{\sum_{b=1}^{B} Load_{bh}} = \frac{\sum_{b=1}^{B}\left[Load_{bh} \bullet \frac{\sum_{i=1}^{12}\sum_{g=1}^{G}\left(HCAOffer_{gi} \bullet UPF_{gbi}\right)}{12}\right]}{\sum_{b=1}^{B} Load_{bh}}.$$

The annual systemwide, historical, cost-adjusted, load-weighted (*annual SHCALW*) LMP for the year is given by the following equation:

Equation K-18 Systemwide, historical, cost-adjusted, load-weighted LMP

$$Annual\_SHCALW\_LMP = \sum_{h=1}^{8760} \frac{TCHCA_h}{\sum_{b=1}^{B} Load_{bh}}.$$

Components of LMP

Table K-2 Components of PJM annual, load-weighted, average LMP: Calendar year 2009

Element	Contribution to LMP	Percent
Coal	$20.53	52.6%
Natural Gas	$12.10	31.0%
10% Cost Adder	$3.73	9.6%
VOM	$2.50	6.4%
Oil	$0.88	2.3%
NO_x	$0.80	2.1%
SO_2	$0.76	1.9%
CO_2	$0.61	1.6%
FMU Adder	$0.17	0.4%
Offline CT Adder	$0.03	0.1%
Municipal Waste	$0.02	0.0%
NA	$0.01	0.0%
Unit LMP Differential	$0.00	0.0%
Shadow Price Limit Adder	($0.01)	(0.0%)
M2M Adder	($0.14)	(0.3%)
Dispatch Differential	($0.15)	(0.4%)
UDS Override Differential	($0.43)	(1.1%)
Markup	($2.38)	(6.1%)
LMP	$39.05	100.0%

There are several components of LMP that are not directly a function of individual unit characteristics:

- **Offline CT Adder.** Offline CTs that are marginal in the UDS solution have $3 added to their operational offer. This is reflected at the CT unit bus and is propagated through the UDS system solution to the LPA marginal unit buses whose offers have been overridden with their respective UDS LMP. The purpose of this adder was to impose a penalty for selecting offline CTs in UDS in order to avoid UDS switching between online CTs and offline CTs. The implementation of Look Ahead UDS (LA UDS) in February 2009 eliminated the occurrence of offline CTs on the margin in UDS and therefore the offline CT adder.[3]

  The offline CT adder is the contribution of this adder to the annual average, load weighted LMP.

- **UDS Override Differential.** The LPA preprocessor determines the set of units eligible to set price in the LPA solution every five minutes. In order to determine eligible units, the preprocessor takes input from UDS in the form of desired MW, unit specific dispatch rates (UDS LMP), zonal dispatch rates, and unit operating limits. The UDS LMP is the dispatch rate calculated based on where units are being dispatched to 15 minutes from the present. The UDS LMP is

3 In January 2009, there were 1,355 intervals where an offline CT was marginal in UDS and a UDS override set the LPA marginal unit bus LMP. In February 2009, there were 5 intervals where an offline CT was marginal in UDS and a UDS override set the LPA marginal unit bus LMP. In April 2009, there was 1 interval where an offline CT was marginal in UDS and a UDS override set the LPA marginal unit bus LMP. There were no offline CTs marginal in the remaining months of 2009.

calculated respecting all transmission and operating constraints and is calculated based on a set of marginal units in the UDS solution. These marginal units set the UDS LMP in UDS in the same way that the LPA marginal units set the LMP.

The LPA preprocessor evaluates each unit against several thresholds designed to measure the extent to which units are currently following the dispatch signals provided by UDS. Units are eligible to set price in the LPA if they meet all the criteria in the preprocessor. A unit's current offer is calculated based on the unit's offer curve and the current state estimated solution. If a unit is following dispatch and its offer is less than or equal to the UDS LMP, the unit is eligible to set price based on its current offer. If a unit's current offer is greater than the UDS LMP and the unit is not a CT, the unit's current offer is automatically overridden with the UDS LMP. When overridden, the unit's current offer becomes the UDS LMP and the unit is again eligible to set price, but it sets price based on the UDS LMP and the characteristics of the UDS marginal units rather than based on the characteristics of the LPA unit. The UDS LMP does not reflect the LPA unit's offer curve and does not represent the offer behavior of the LPA units whose offers are overridden. The LMPs resulting from the LPA calculations do reflect the network characteristics of the LPA marginal unit, including the UPF and DFAX. However, when a UDS override occurs and the overridden unit is marginal in the LPA, the UDS solution marginal units have a direct effect on the LPA marginal prices.

In addition to the automatic overrides, another type of override occurs when the PJM LMP Operator manually overrides the LPA marginal unit bus LMP with its respective UDS LMP. This type of override occurs less frequently and is generally used to ensure that LMPs reflect how the UDS redispatches units for a transmission constraint. For example, if the LPA is selecting a raise help unit to relieve a constraint and the UDS is selecting a lower help unit to relieve the same constraint, the PJM LMP Operator will place the raise help unit on its UDS LMP. This action will either cause the lower help unit to be marginal in the LPA or the raise help unit to be marginal on its UDS LMP. Either of these actions will result in the same LMPs in the LPA and be consistent with the controlling action used in the UDS.

Table K-3 shows the percentage of five minute intervals and the percentage of all marginal units where a UDS override occurred during calendar year 2009. In 2009, 91 percent of all five minute intervals had at least one marginal unit whose offer was automatically overridden with its respective UDS LMP. Two percent of all five minute intervals had at least one marginal unit whose offer was manually overridden with its respective UDS LMP. In 2009, 81 percent of all marginal units had their offer automatically overridden with its respective UDS LMP. One percent of all marginal units had their offer manually overridden with its respective UDS LMP.

Table K-3 Percentage of five minute intervals and marginal units having a UDS LMP override: Calendar year 2009

Type	Percent of 5 Minute Intervals Overriden with UDS LMP	Percent of Marginal Units Overriden with UDS LMP
Automatic	91%	81%
Manual	2%	1%
Total	93%	82%

When an override occurs and the price difference cannot be explained with the UDS solution as a result of missing data, the difference is categorized as "UDS override differential." The UDS override differential is calculated as the difference between the UDS LMP at the LPA marginal unit bus and the actual offer of the LPA marginal unit. The UDS override differential is the contribution of these differentials to annual average, load weighted LMP.

- **Dispatch Differential.** Measures any difference between the bus LMP and the LPA operational offer or the UDS LMP at the UDS marginal unit and its operational offer based on desired MW. The dispatch differential is the contribution of this difference to the annual average, load weighted LMP.

- **M2M Adder.** The M2M adder occurs when PJM uses the shadow price calculated by the Midwest ISO as stated in the Joint Operating Agreement between PJM and the Midwest ISO.[4] When PJM uses the Midwest ISO shadow price, a marginal unit inside PJM is not identified for the M2M constraint. In order to reflect the cost of the M2M constraint in the ex ante LMP at each generator, the shadow price is multiplied by the DFAX of each generator to the M2M constraint. The result of this multiplication is also equal to the congestion component of the ex ante LMP at each generator bus relative to the M2M constraint. When a UDS override occurs and the LPA marginal unit offer is set equal to the ex ante LMP, the M2M adder reflects the contribution of the M2M constraint, rather than the UDS marginal unit, to the annual average, load weighted LMP.

- **Shadow Price Limit Adder.** PJM uses shadow price limits for constraints and the RT UDS economic dispatch algorithm enforces these limits. The procedures for setting the shadow price limits are flexible and the exact rationale for setting the limits is not clearly stated. When a shadow price limit is enforced on a constraint a marginal unit is not identified for the constraint and the transmission constraint is treated as the marginal resource in the least cost dispatch solution. The marginal cost of using this resource is equal to the shadow price limit for the constraint. In order to reflect the cost of the constraint in the ex ante LMP at each generator, the shadow price is multiplied by the DFAX of each generator to the constraint. The result of this multiplication is also equal to the congestion component of the ex ante LMP at each generator bus. When a UDS override occurs and the LPA marginal unit offer is set equal to the ex ante LMP, the shadow price limit adder reflects the contribution of the constraint at its shadow price limit, rather than the UDS marginal unit, to the annual average, load weigUnit LMP differential. Where the product of the UDS UPFs and UDS marginal unit operational offers does not equal the LPA marginal unit bus LMP, this component measures that difference. The unit LMP differential is the contribution of this difference to the annual average, load weighted LMP.

- **NA.** NA is the net difference between the UPF load weighted LMP calculation and the accounting load weighted LMP. NA is the contribution of this difference to the annual average, load weighted LMP.

4 See PJM. "Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C." (December 11, 2008) (Accessed January 15, 2010) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/joa-complete.ashx> (1,534 KB).

APPENDIX L – THREE PIVOTAL SUPPLIER TEST

PJM markets are designed to promote competitive outcomes. Market design is the primary means of achieving and promoting competitive outcomes in the PJM markets. One of the Market Monitoring Unit's (MMU's) primary goals is to identify actual or potential market design flaws.[1] PJM's market power mitigation goals have focused on market designs that promote competition (i.e., a structural basis for competitive outcomes) and on limiting market power mitigation to instances where market structure is not competitive and thus where market design alone cannot mitigate market power. In the PJM Energy Market, this occurs only in the case of local market power. When a transmission constraint creates the potential for local market power, PJM applies a structural test to determine if the local market is competitive, applies a behavioral test to determine if generator offers exceed competitive levels and applies a market performance test to determine if such generator offers would affect the market price.

The structural test for implementing offer capping set forth in the PJM Amended and Restated Operating Agreement (OA) Schedule 1, Sections 6.4.1(e) and (f) is the three pivotal supplier test. The three pivotal supplier test is applied by PJM on an ongoing basis in order to determine whether offer capping is required for any transmission constraint. The three pivotal supplier test defined in the OA represents a significant evolution in accuracy because the test is applied in real time using the actual data used by the dispatchers to dispatch the system including transmission constraints and the real-time details of incremental generator availability.

As a result of PJM's implementation of the three pivotal supplier test in real time, the actual competitive conditions associated with each binding constraint are analyzed in real time as they arise. The three pivotal supplier test replaced the prior approach which was to offer cap all units required to resolve a binding constraint. The application of the three pivotal supplier test has meant a reduction in the application of offer capping. As a result of the application of the three pivotal supplier test, offer capping is applied only at times when the local market structure is not competitive and only to those participants with structural market power.

Three Pivotal Supplier Test: Background

By order issued April 18, 2005, the United States Federal Energy Regulatory Commission (FERC) set for hearing, in Docket No. EL04-121-000, PJM's proposal: a) to exempt the AP South Interface from PJM's offer-capping rules; and b) to conduct annual competitive analyses to determine whether additional exemptions from offer capping are warranted. By order issued July 5, 2005, the FERC also set for hearing, in Docket No. EL03-236-006, PJM's three pivotal supplier test. The Commission further set for hearing issues related to the appropriateness of implementing scarcity pricing in PJM. In the July order, the Commission consolidated Docket No. EL04-121-000 and Docket No. EL03-236-006.

On November 16, 2005, PJM filed a "Settlement Agreement" resolving all issues set for hearing in Dockets Nos. EL04-121-000 and ER03-236-006, which included the application of the three pivotal supplier ("TPS") test, provisions for scarcity pricing, offer caps for frequently mitigated units and

1 PJM. "Open Access Transmission Tariff (OATT)," "Attachment M: Market Monitoring Plan," Third Revised Sheet No. 452 (Effective July 17, 2006).

competitive issues associated with certain of PJM's internal interfaces. The Commission approved this settlement on January 27, 2006, and the TPS test was implemented shortly thereafter.[2]

On January 15, 2008 the Maryland Public Service Commission filed a complaint against PJM requesting that the Commission remove PJM's market rule provisions that exempt certain generation resources from energy offer price mitigation and that the Commission initiate an investigation to determine whether generators exempt from mitigation have exercised market power and provide retroactive relief where appropriate. By order issued May 16, 2008, the Commission granted the request to remove the mitigation exemptions, but also established a Section 206 investigation and paper hearing in Docket No. EL08-47-000 to consider the justness and reasonableness of PJM's the mitigation program adopted in settlement ("May 16th Order").[3] The hearing was held in abeyance pending the earlier of either the conclusion of the ongoing stakeholder process conducted primarily in the Three Pivotal Supplier Task Force convened to evaluate the performance of the TPS test and its potential application to the Regulation Market.

PJM filed a report on the status of stakeholder progress on the issue on September 5, 2008, explaining that no consensus had been reached, but that the process had provided stakeholders a greater understanding of the theory behind and the implementation of the TPS test. PJM declined to propose any revisions to the TPS test.

On October 6, 2008, numerous parties including the MMU filed comments on the merits of the TPS test and alternatives. A smaller group filed reply comments on November 5, 2008. The MMU filed on November 25, 2008 a supplemental response.

On February 2, 2009, the Commission issued an initial order in its investigation finding that "there is not sufficient evidence to meet the Federal Power Act section 206 burden to show that the three-pivotal-supplier test … is unjust and unreasonable as it relates to assessing the structural competitiveness of the PJM energy market."[4] The Commission, however, found that "because default bids do not clearly and explicitly provide for the inclusion of opportunity costs, especially for energy and environmentally-limited resources, the mitigation measures related to determining default bids are unjust and unreasonable."[5] The Commission, therefore, required PJM "to make a compliance filing that proposes an approach for addressing the incorporation of opportunity costs in mitigated offers" on or before July 31, 2009.[6] The Commission also provided that "within 30 days after that filing, other parties may provide comments on the PJM proposal or submit their own specific proposals for resolving this issue." [7]

Several parties requested rehearing of the May 16th Order, which the Commission denied on December 19, 2008.[8]

On October 1, 2008, in Docket No. ER09-13-000, PJM filed to add the TPS test to the Regulation Market. On October 20, 2008, numerous parties filed comments or protest, including the MMU, which supported PJM's proposal but indicated reservations about certain aspects of its implementation.

2 114 FERC ¶61,076 (2006).
3 123 FERC ¶ 61,169 (2008).
4 *PJM Interconnection, L.L.C.*, 126 FERC ¶ 61,145 at P 1.
5 *Id.* at P 42.
6 *Id.* at P 48.
7 *Id.*
8 125 FERC ¶ 61,340 (2008).

The MMU requested that the Commission direct the MMU to report on those aspects of PJM's proposal. On November 26, 2008, the Commission approved the application of the TPS test to the Regulation Market, directing the MMU to file the requested report by November 26, 2009.[9]

Market Structure Tests and Market Power Mitigation: Core Concepts

A test for local market power based on the number of pivotal suppliers has a solid basis in economics and is clear and unambiguous to apply in practice. There is no perfect test, but the three pivotal supplier test for local market power strikes a reasonable balance between the requirement to limit extreme structural market power and the goal of limiting intervention in markets when competitive forces are adequate. The three pivotal supplier test for local market power is also a reasonable application of the logic contained in the Commission's market power tests.

The Commission adopted market power screens and tests in the AEP Order.[10] The AEP Order defined two indicative screens and the more dispositive delivered price test. The Commission's delivered price test for market power defines the relevant market as all suppliers who offer at or below the clearing price times 1.05 and, using that definition, applies pivotal supplier, market share and market concentration analyses. These tests are failed if, in the relevant market, the supplier in question is pivotal, has a market share in excess of 20 percent or if the Herfindahl-Hirschman Index (HHI) exceeds 2500. The Commission also recognized that there are interactions among the results of each screen under the delivered price test and that some interpretation is required and, in fact, is encouraged.[11]

The three pivotal supplier test, as implemented, is consistent with the Commission's market power tests, encompassed under the delivered price test. The three pivotal supplier test is an application of the delivered price test to the Real-Time Energy Market, the Day-Ahead Energy Market and the Reliability Pricing Model (RPM) Capacity Market. The three pivotal supplier test explicitly incorporates the impact of excess supply and implicitly accounts for the impact of the price elasticity of demand in the market power tests. The three pivotal supplier test includes more competitors in its definition of the relevant market than the Commission's delivered price test. While the Commission's delivered price test defines the relevant market to include all offers with costs less than, or equal to, 1.05 times the market price, the three pivotal supplier test includes all offers with costs less than, or equal to, 1.50 times the clearing price for the local market.

The three pivotal supplier test is also consistent with the Commission's delivered price test in that it tests for the interaction between individual participant attributes and features of the relevant market structure. The three pivotal supplier test is an explicit test for the ability to exercise unilateral market power as well as market power via coordinated action, based on economic theory, which accounts simultaneously for market shares and the supply-demand balance in the market.

The results of the three pivotal supplier test can differ from the results of the HHI and market share tests. The three pivotal supplier test can show the existence of structural market power when the HHI is less than 2500 and the maximum market share is less than 20 percent. The three pivotal

9 125 FERC ¶ 61,231(2008).
10 107 FERC ¶ 61,018 (2004) (AEP Order).
11 107 FERC ¶ 61,018 (2004).

supplier test can also show the absence of market power when the HHI is greater than 2500 and the maximum market share is greater than 20 percent. The three pivotal supplier test is more accurate than the HHI and market share tests because it focuses on the relationship between demand and the most significant aspect of the ownership structure of supply available to meet it. A market share in excess of 20 percent does not matter if the holder of that market share is not jointly pivotal and is unlikely to be able to affect the market price. A market share less than 20 percent does not matter if the holder of that market share is jointly pivotal and is likely to be able to affect the market price. Similarly, an HHI in excess of 2500 does not matter if the relevant owners are not jointly pivotal and are unlikely to be able to affect the market price. An HHI less than 2500 does not matter if the relevant owners are jointly pivotal and are likely to be able to affect the market price.[12]

The three pivotal supplier test was designed in light of actual elasticity conditions in load pockets in wholesale power markets in PJM. The price elasticity of demand is a critical variable in determining whether a particular market structure is likely to result in a competitive outcome. A market with a specific set of market structure features is likely to have a competitive outcome under one range of demand elasticity conditions and a noncompetitive outcome under another set of elasticity conditions. It is essential that market power tests account for actual elasticity conditions and that evaluation of market power tests neither ignore elasticity nor make counterfactual elasticity assumptions. As the Commission stated, "In markets with very little demand elasticity, a pivotal supplier could extract significant monopoly rents during peak periods because customers have few, if any, alternatives."[13] The Commission also stated:

> In both of these models, the lower the demand elasticity, the higher the mark-up over marginal costs. It must be recognized that demand elasticity is extremely small in electricity markets; in other words, because electricity is considered an essential service, the demand for it is not very responsive to price increases. These models illustrate the need for a conservative approach in order to ensure competitive outcomes for customers because many customers lack one of the key protections against market power: demand response.[14]

The Commission defines the relevant market under the delivered price test "by identifying potential suppliers based on market prices, input costs, and transmission availability, and calculates each supplier's economic capacity for each season/load condition." The Commission defines the relevant market to include suppliers with "costs less than or equal to 1.05 times the market price," i.e. those "suppliers that could sell into the destination market at a price less than or equal to 5 percent over the market price."[15] Thus, the relevant market includes all supply that is potentially competitive with the supplier and excludes supply that is not potentially competitive with the supplier.

The Commission's market based rates analysis then applies the components of the delivered price test to the relevant market. A supplier fails if the supplier is pivotal (one pivotal supplier test), if it has a market share greater than or equal to 20 percent, or if the HHI in the relevant market is greater than or equal to 2500.[16] A supplier is pivotal under the market power test if demand in the relevant market cannot be met without its supply (one pivotal supplier test).

12 For detailed examples, see Joseph E. Bowring, PJM market monitor. "MMU Analysis of Combined Regulation Market," PJM Market Implementation Committee Meeting (December 20, 2006).
13 107 FERC ¶ 61,018 (2004).
14 107 FERC ¶ 61,018 (2004).
15 AEP Order at App. F; *see also Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act: Policy Statement*, Order No. 592, FERC Stats. & Regs. ¶ 31,044, *mimeo* at 6 (1996), reconsideration denied, Order No. 592-A, 79 FERC ¶ 61,321 (1997) ("Merger Policy Statement"); Revised Filing Requirements Under Part 33 of the Commission's Regulations, Order No. 642, FERC Stats. & Regs. ¶ 31,111 (2000), *order on reh'g*, Order No. 642-A, 94 FERC ¶ 61,289 (2001); Order No. 697 at P 108.
16 Order No. 697 at P 111.

The Commission recognizes the interactions among the multiple analyses under the delivered price test and "encourages the most complete analysis of competitive conditions in the market as the data allow."[17]

For example, passing a single-pivotal supplier test does not demonstrate the absence of structural market power because market participants can coordinate their behavior with other suppliers and can do so without overt interaction. The Commission stated:

> Concentration statistics can indicate the likelihood of coordinated interaction in a market. All else being equal, the higher the HHI, the more firms can extract excess profits from the market. Likewise a low HHI can indicate a lower likelihood of coordinated interactions among suppliers and could be used to support a claim of a lack of market power by a seller that is pivotal or does have a 20 percent or greater market share in some or all season/load conditions. For example, a seller with a market share of 20 percent or greater could argue that … it would be unlikely to possess market power in an unconcentrated market (HHI less than 1000).[18]

In a market with an inelastic demand curve, the existence of two jointly pivotal suppliers, regardless of the amount of excess capacity available, does not provide a market structure that will result in a competitive outcome. The 20 percent market share and the HHI screen are also weak screens for structural market power on a stand-alone basis. A market share in excess of 20 percent does not demonstrate market power if the holder of that market share is not jointly pivotal and is unlikely to be able to affect the market price. A market share less than 20 percent does not demonstrate the absence of market power if the holder of that market share is jointly pivotal and is likely to be able to affect the market price. An HHI in excess of 2500 does not demonstrate market power if the relevant owners are not jointly pivotal and are unlikely to be able to affect the market price. An HHI less than 2500 does not demonstrate the absence of market power if the relevant owners are jointly pivotal and are likely to be able to affect the market price.[19]

The three pivotal supplier test is a reasonable application of the Commission's delivered price test to the case of load pockets that arise in a market based on security-constrained, economic dispatch with locational market pricing and extremely inelastic demand. The three pivotal supplier test also exists in the context of a local market power mitigation rule that relies on a structure test, a participant behavior test and a market impact test. The three pivotal supplier test explicitly incorporates the relationship between supply and demand in the definition of pivotal, and it provides a clear test for whether excess supply is adequate to offset other structural features of the market and results in an adequately competitive market structure. The greater the supply relative to demand, the less likely that three suppliers will be jointly pivotal, all else equal.

The three pivotal supplier test represents a significant modification of the previously existing PJM local market power rule, which did not include an explicit market structure test. The goal of applying a market structure test is to continue to limit the exercise of market power by generation owners in load pockets but to lift offer capping when the market structure makes the exercise of market power less likely. The goal of the three pivotal supplier test, proposed by PJM, was not to weaken

17 *See* Order No. 697 at PP 111–117; AEP Order at PP 111–12.
18 Order No. 697 at P 111.
19 For detailed examples, see Joseph E. Bowring, PJM market monitor. "MMU Analysis of Combined Regulation Market," PJM Market Implementation Committee Meeting (December 20, 2006).

the local market power rules but to make them more flexible by adding an explicit market structure test. As recognized by PJM when the local market power rule was proposed in 1997 and has continued to be the case, the local markets created by transmission constraints are generally not structurally competitive. Nonetheless, it is appropriate to have a clear test as to when a local market is adequately competitive to permit the relaxation of local market power mitigation. The three pivotal supplier test proposed by PJM is not a guarantee that suppliers will behave in a competitive manner in load pockets. The three pivotal supplier test is a structural test that is not a perfect predictor of actual behavior. The existence of this risk is the reason that the PJM Tariff language also includes the ability of the MMU to request that the Commission reinstate offer caps in cases where there is not a competitive outcome.

Three Pivotal Supplier Test: Mechanics

The three pivotal supplier test measures the degree to which the supply from three generation suppliers is required in order to meet the demand to relieve a constraint. Two key variables in the analysis are the demand and the supply. The demand consists of the incremental, effective MW required to relieve the constraint. The supply consists of the incremental, effective MW of supply available to relieve the constraint at a distribution factor (DFAX) greater than, or equal to, the DFAX used by PJM in operations.[20] For purposes of the test, incremental effective MW are attributed to specific suppliers on the basis of their control of the assets in question. Generation capacity controlled directly or indirectly through affiliates or through contracts with third parties are attributed to a single supplier.

The supply directly included as relevant to the market in the three pivotal supplier test consists of the incremental, effective MW of supply that are available at a price less than, or equal to, 1.5 times the clearing price (P_c) that would result from the intersection of demand (constraint relief required) and the incremental supply available to resolve the constraint. This measure of supply is termed the relevant effective supply (S) in the market for the relief of the constraint in question. In every case, incrementally available supply is measured as incremental effective MW of supply, as shown in Equation L-1, and the clearing price (P_c) is defined as shown in Equation L-2:

Equation L-1 Incremental effective MW of supply

$MW \bullet DFAX$; and

Equation L-2 Price of clearing offer

$$P_c = \frac{Offer_c - SMP}{DFAX_c} .$$

To be part of the relevant market, the effective offer of incremental supplier *i* must be less than, or equal to, 1.5 times P_c:

20 A unit's contribution toward effective, incrementally available supply is based on the DFAX of the unit relative to the constraint and the unit's incrementally available capacity over current load levels, to the extent that the capacity in question can be made available within an hour of the time the relief will be needed. Effective, incrementally available MW from an unloaded 100 MW 15-minute start combustion turbine (CT) with a DFAX of 0.05 to a constraint would be 5 MW relative to the constraint in question. Effective, incrementally available MW from a 200 MW steam unit, with 100 MW loaded, a 50 MW ramp rate and a DFAX of 0.5 to the constraint would be 25 MW.

Equation L-3 Relevant and effective offer

$$P_{ie} = \frac{Offer_i - SMP}{DFAX_i} \leq 1.5 \bullet P_c .$$

Where the effective incremental supply of supplier *i* is a function of price:

Equation L-4 Relevant and effective supply of supplier i

$$S_i = MW\left(P_{ie}\right) \bullet DFAX_i .$$

Where S_i is the relevant, incremental and effective supply of supplier *i*, total relevant, incremental and effective supply for suppliers *i*=1 to n is shown in Equation L-5:

Equation L-5 Total relevant, effective supply

$$S = \sum_{i=1}^{n} S_i .$$

Each effective supplier, from 1 to n, is ranked, from the largest to the smallest relevant effective supply, relative to the constraint for which it is being tested. In the first iteration of the test, the two largest suppliers are combined with the third largest supplier, and this combined supply is subtracted from total relevant effective supply. The resulting net amount of relevant effective supply is divided by the total relief required (*D*). Where *j* defines the supplier being tested in combination with the two largest suppliers (initially the third largest supplier with *j*=3), Equation L-6 shows the formula for the three pivotal supplier metric, i.e., the residual supply index for three pivotal suppliers (RSI3):

Equation L-6 Calculating the three pivotal supplier test

$$RSI3_j = \frac{\sum_{i=1}^{n} S_i - \sum_{i=1}^{2} S_i - S_j}{D} .$$

Where *j*=3, if $RSI3_j$ is less than, or equal to, 1.0, then the three largest suppliers in the market for the relief of the constraint fail the three pivotal supplier test. That is, the three largest suppliers are jointly pivotal for the local market created by the need to relieve the constraint using local, out-of-merit units. If $RSI3_j$ is greater than 1.0, then the three largest potential suppliers of relief MW pass the test and the remaining suppliers (*j*=4..n) pass the test. In the event of a failure of the three largest suppliers, further iterations of the test are needed, with each subsequent iteration testing a subsequently smaller supplier (*j*=4..n) in combination with the two largest suppliers. In each iteration, if $RSI3_j$ is less than 1.0, it indicates that the tested supplier, in combination with the two largest suppliers, has failed the test. Iterations of the test continue until the combination of the two largest suppliers and a supplier *j* result in $RSI3_j$ greater than 1.0. When the result of this process is that $RSI3_j$ is greater than 1.0, the remaining suppliers pass the test.

If a supplier fails the test for a constraint, units that are part of a supplier's relevant effective supply with respect to a constraint can have their offers capped at cost plus 10 percent, or cost plus relevant adders for frequently mitigated units and associated units. Offer capping only occurs to the extent that the units of this supplier's relevant, effective supply are offered at greater than cost plus 10 percent and are actually dispatched to contribute to the relief of the constraint in question.

Defining the market

The goal of defining the relevant market is to include those producers that actually compete to determine the market price or could actually compete to determine the market price. Conversely, the goal of defining the relevant market is to exclude those units that are not meaningful competitors and therefore do not have an impact on the clearing price. The existence of market power within that defined market depends on the ability of the firm to raise price while continuing to sell its output. A firm cannot successfully increase the market price above the competitive level if competitors would replace its output when it did so.

The Commission definition of the relevant market includes all suppliers which have costs less than or equal to 1.05 times the clearing price. The Commission definition means that, if the marginal unit sets the clearing price based on an offer of $200 per MWh, all units with costs less than, or equal to, $210 per MWh have a competitive effect on the offer of the marginal unit. These units are all defined to be meaningful competitors in the sense that it is assumed that their behavior constrains the behavior of the marginal and inframarginal units. The three pivotal supplier definition means that, if the marginal unit sets the clearing price based on an offer of $200 per MWh, all units with costs less than, or equal to, $300 per MWh have a competitive effect on the offer of the marginal unit. These units are all defined to be meaningful competitors in the sense that it is assumed that their behavior constrains the behavior of the marginal and inframarginal units. The three pivotal supplier test incorporates a definition of meaningful competitors that is at the extremely high end of inclusive. It is questionable whether a unit with a competitive offer price of $300 meaningfully constrains the offer of a $200 unit. This broad market definition is combined with the recognition that multiple owners can be jointly pivotal. The three pivotal supplier test includes three pivotal suppliers while the Commission test includes only one pivotal supplier.

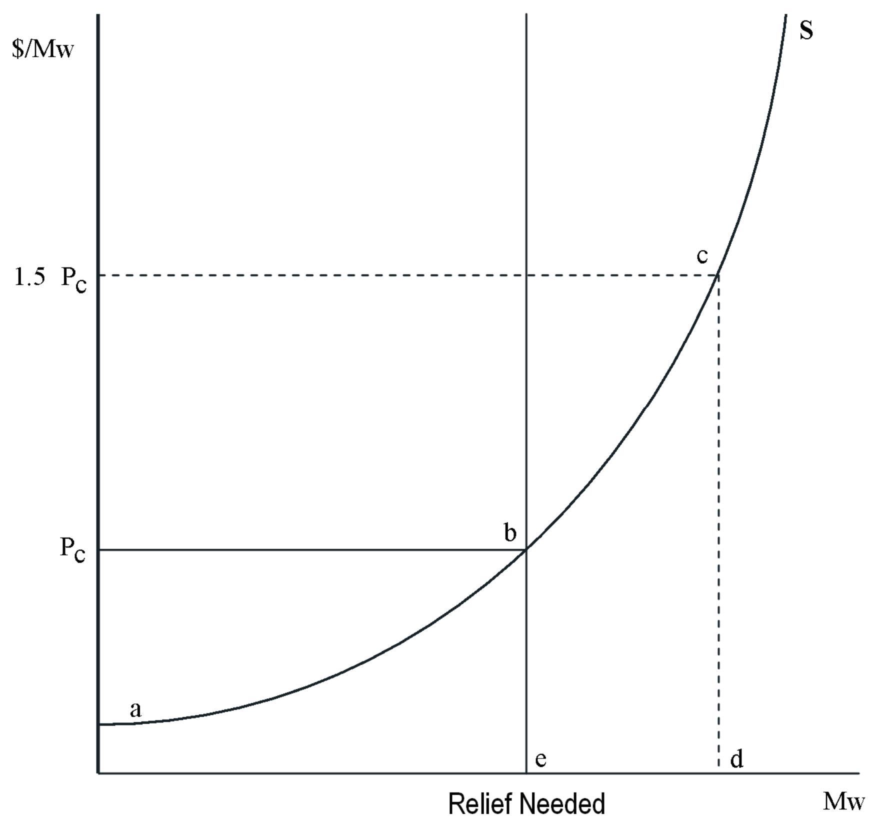
The three pivotal supplier test is designed to test the relevant market. For example, in the case of the market for out of merit generation needed to relieve a constraint in real time, the three pivotal supplier test examines the market specifically available to provide that relief. Under these conditions, the three pivotal supplier test measures the degree to which the supply from three generation suppliers, as defined by PJM's market solution software, is required in order to meet the demand to relieve a constraint. The market demand consists of the incremental, effective MW required to relieve the constraint. The market supply consists of the incremental, effective MW of supply available to relieve the constraint.[21] For purposes of the test, incremental effective MW are attributed to specific suppliers on the basis of their control of the assets in question. Generation capacity controlled directly or indirectly through affiliates or through contracts with third parties are attributed to a single supplier.

21 A unit's contribution toward effective, incrementally available supply is based on the DFAX of the unit relative to the constraint and the unit's incrementally available capacity over current load levels, if the capacity in question is available within an hour of the time the relief will be needed. Effective, incrementally available MW from an unloaded 100 MW 15-minute start combustion turbine (CT) with a DFAX of 0.05 to a constraint would be 5 MW relative to the constraint in question. Effective, incrementally available MW from a 200 MW steam unit, with 100 MW loaded, a 50 MW ramp rate and a DFAX of 0.5 to the constraint would be 25 MW.

The supply directly included as relevant to the market in the three pivotal supplier test consists of the incremental, effective MW of supply that are available at a price less than, or equal to, 1.5 times the clearing price (P_c) that would result from the intersection of demand (constraint relief required) and the incremental supply available to resolve the constraint. This measure of supply is termed the relevant effective supply (S) in the market for the relief of the constraint in question. In every case, incrementally available supply is measured as incremental effective MW of supply, as shown in Equation L-1, and the clearing price (P_c) is defined as shown in Equation L-1 above.

Figure L-1 illustrates the interaction between the relief requirement and the effective supply available, as recognized by PJM's solution software. The clearing price (P_c) is generated at the point of intersection of the relief required (D) and relevant effective supply (S). The effective cost and MW pairs from a particular participant are based on the lesser of the participant's cost or price schedule, if the unit is offline, or the current operational (price or cost) schedule if the unit is already being dispatched by PJM. The relief requirement can be fully met at the point of intersection (b) of (D) and (S) by the effective MW available at P_c (e). However, as indicated above, the market defined for the test also includes potentially effective MW in excess of what is needed to clear the market (d), defined as the effective MW available at a price less than, or equal to, 1.5 times the clearing price (P_c).

Figure L-1 Definition of relevant market



Unlike structural tests that define markets by geographic proximity, TPS makes explicit and direct use of the incremental, effective MW of supply available to relieve the constraint at a distribution factor (DFAX) greater than, or equal to, the DFAX used by PJM in operations. Only the supply that is part of the market as defined by the reality of the electric network as measured by unit characteristics and distribution factors is included in the three pivotal supplier test, to the extent that it is incremental, effective MW of supply that is available at a price less than, or equal to, 1.5 times the clearing price (P_c) that would result from the intersection of demand (constraint relief required) and the incremental supply available to resolve the constraint.

APPENDIX M – STANDARD MARKET METRICS

The Market Monitoring Unit (MMU) uses a number of measures of market structure, participant behavior and market performance. These metrics include, but are not limited to the residual supply index, markup, net revenue, market share and the Herfindahl-Hirschman Index.[1]

Residual Supply Index (RSI)

PJM utilizes the Three Pivotal Supplier (TPS) Test in the Regulation Market, the Capacity Market and the Energy Market to detect structural market power. The residual supply index is the metric used to determine the outcome of the TPS. Each supplier, from 1 to n, is ranked from the largest to the smallest offered MW of eligible regulation supply in each hour. Suppliers are then tested in order, starting with the three largest suppliers. In each iteration of the test, the two largest suppliers are combined with a third supplier, and the combined supply is subtracted from total effective supply. The resulting net amount of eligible supply is divided by the demand for the hour (*D*).

Where *j* defines the supplier being tested in combination with the two largest suppliers (initially the third largest supplier with *j*=3), Equation M-1 shows the formula for the residual supply index for three pivotal suppliers (RSI3):

Equation M-1 Calculating the three pivotal supplier test

$$RSI3_j = \frac{\sum_{i=1}^{n} S_i - \sum_{i=1}^{2} S_i - S_j}{D}$$

Where *j*=3, if $RSI3_j$ is less than or equal to 1.0, then the three suppliers are jointly pivotal and the suppliers being tested fail the three pivotal supplier test. Iterations of the test continue until the combination of the two largest suppliers and a supplier *j* result in $RSI3_j$ greater than 1.0. When the result of this process is that $RSI3_j$ is greater than 1.0, the remaining suppliers pass the test.

Markup

The price-cost markup index is a measure of conduct or behavior by the owners of generating units and not a measure of market impact. For marginal units, the markup index is a measure of market power. For units not on the margin, the markup index is a measure of the intent to exercise market power or, in cases where the markup results in higher-priced units replacing lower-priced units in the dispatch, also a measure of market power. A positive markup by marginal units results in a difference between the observed market price and the competitive market price. The goal of the markup analysis is both to calculate the actual markups by marginal units (market conduct) and to estimate the impact of those markups on the difference between the observed market price and the competitive market price (market impact or market performance). The results must be interpreted carefully, however, because the impact is not based on a full redispatch of the system. The markup index for each marginal unit is normalized and can vary from -1.00 when the offer price is less than

1 For a list of indices used by the MMU, see the Monitoring Analytics website: http://www.monitoringanalytics.com/reports/Market_Messages/Messages/MA_Market_Monitoring_Indices_20091214.pdf

marginal cost, to 1.00 when the offer price is higher than marginal cost. In the energy market, in order to normalize the index results (i.e., bound the results between +1.00 and -1.00), the index is calculated as (Price – Cost)/Price when price is greater than cost, and (Price – Cost)/Cost when price is less than cost. This index calculation method weights the impact of individual unit markups using sensitivity factors.[2]

Net Revenue

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

Market Share

Market share is calculated based on participant specific volumes cleared in each iteration of the relevant market. For example, in the day-ahead energy market, the market clears every hour. Market shares are calculated in each hour based on each participant’s cleared volumes in that hour.

A participant’s market share is only calculated for those iterations of the market in which the participant cleared volume. For example, if Participant A delivered power only in hours 14 and 15 of a given day, Participant A’s market share would be calculated only for hours 14 and 15. When calculating average market share for the day, Participant A’s average market share would take the average of the market iterations within the day where Participant A cleared market volumes: hours 14 and 15. When calculating average market share for the year, Participant A’s average market share would take the average of the market iterations within the year where Participant A cleared market volumes: hours 14 and 15. This ensures that participant specific market shares are examined within their relevant market space.

Herfindahl-Hirschman Index (HHI)

Concentration ratios are a summary measure of market share, a key element of market structure. High concentration ratios indicate that comparatively small numbers of sellers dominate a market; low concentration ratios mean larger numbers of sellers split market sales more equally. The best tests of market competitiveness are direct tests of the conduct of individual participants and their

2 Sensitivity factors define the impact of each marginal unit on LMP at every bus on the system. See the *2009 State of the Market Report for PJM*, Volume II, Appendix K, “Calculation and Use of Generator Sensitivity/Unit Participation Factors.”

impact on price. The price-cost markup index is one such test and direct examination of offer behavior by individual market participants is another. Low aggregate market concentration ratios establish neither that a market is competitive nor that participants are unable to exercise market power. High concentration ratios do, however, indicate an increased potential for participants to exercise market power.

Despite their significant limitations, concentration ratios provide useful information on market structure. The concentration ratio used here is the Herfindahl-Hirschman Index (HHI), calculated by summing the squares of the market shares of all firms in a market.

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

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

APPENDIX N – GLOSSARY

Aggregate	Combination of buses or bus prices.
Ancillary Services	Those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Provider's Transmission System in accordance with Good Utility Practice..
Area Control Error (ACE)	Area Control Error of the PJM RTO is the actual net interchange minus the biased scheduling net interchange, including time error. It is the sum of tie-in errors and frequency errors.
Associated unit (AU)	A unit that is located at the same site as a frequently mitigated unit (FMU) and which has identical electrical and economic impacts on the transmission system as an FMU but which does not qualify for FMU status.
Auction Revenue Right (ARR)	A financial instrument entitling its holder to auction revenue from Financial Transmission Rights (FTRs) based on locational marginal price (LMP) differences across a specific path in the Annual FTR Auction.
Automatic Generation Control (AGC)	An automatic control system comprised of hardware and software. Hardware is installed on generators allowing their output to be automatically adjusted and monitored by an external signal and software is installed facilitating that output adjustment.
Average hourly LMP	An LMP calculated by averaging hourly LMP with equal hourly weights; also referred to as a simple average hourly LMP.
Avoidable cost rate (ACR)	The costs that a generation owner would not incur if the generating unit did not operate for one year, in particular the delivery year. The ACR calculation is based on the categories of cost that are specified in Section 6.8 of Attachment DD of the PJM Tariff.
Avoidable Project Investment Recovery Rate (APIR)	A component of the avoidable cost rate (ACR) calculation. Project investment is the capital reasonably required to enable a capacity resource to continue operating or improve availability during peak-hour periods during the delivery year.

Balancing energy market	Energy that is generated and financially settled during real time.
Base Residual Auction (BRA)	Reliability Pricing Model (RPM) auction held in May three years prior to the start of the delivery year. Allows for the procurement of resource commitments to satisfy the region's unforced capacity obligation and allocates the cost of those commitments among the LSEs through the Locational Reliability Charge.
Bilateral agreement	An agreement between two parties for the sale and delivery of a service.
Black Start Unit	A generating unit with the ability to go from a shutdown condition to an operating condition and start delivering power without any outside assistance from the transmission system or interconnection.
Bottled generation	Economic generation that cannot be dispatched because of local operating constraints.
Burner tip fuel price	The cost of fuel delivered to the generator site equaling the fuel commodity price plus all transportation costs.
Bus	An interconnection point.
Capacity deficiency rate (CDR)	The CDR was designed to reflect the annual fixed costs of a new combustion turbine (CT) in PJM and the annual fixed costs of the associated transmission investment, including a return on investment, depreciation and fixed operation and maintenance expense, net of associated energy revenues. The CDR is used in applying penalties for capacity deficiencies. To express the CDR in terms of unforced capacity, it must be further divided by the quantity 1 minus the EFORd.
Capacity Emergency Transfer Limit (CETL)	The capability of the transmission system to support deliveries of electric energy to a given area experiencing a localized capacity emergency as determined in accordance with the PJM Manuals.
Capacity queue	A collection of Regional Transmission Expansion Planning (RTEP) capacity resource project requests received during a particular timeframe and designating an expected in-service date.

Combined Cycle (CC)	An electric generating technology in which electricity and process steam are produced from otherwise lost waste heat exiting from one or more combustion turbines. The exiting heat is routed to a conventional boiler or to a heat recovery steam generator for use by a conventional steam turbine in the production of electricity. This process increases the efficiency of the electric generating facility.
Combustion Turbine (CT)	A generating unit in which a combustion turbine engine is the prime mover for an electrical generator.
Congestion Management Process (CMP)	A process used between neighboring balancing authorities to coordinate the re-dispatch of resources to relieve transmission constraints.
Control Zone	An area within the PJM Control Area, as set forth in the PJM Open Access Transmission Tariff and the RAA. Schedule 16 of the RAA defines the distinct zones that comprise the PJM Control Area.
Decrement Bids (DEC)	An hourly bid, expressed in MWh, to purchase energy in the PJM Day-Ahead Energy Market if the Day-Ahead LMP is less than or equal to the specified bid price. This bid must specify hourly quantity, bid price and location (transmission zone, hub, aggregate or single bus).
Demand deviations	Hourly deviations in the demand category, equal to the difference between the sum of cleared decrement bids, day-ahead load, day-ahead sales, and day-ahead-exports, to the sum of real-time load, real-time sales, and real-time exports.
Demand Resource	A capacity resource with a demonstrated capability to provide a reduction in demand or otherwise control load. A Demand Resource may be an existing or planned resource.
Dispatch Rate	The control signal, expressed in dollars per MWh, calculated and transmitted continuously and dynamically to direct the output level of all generation resources dispatched by PJM in accordance with the Offer Data.
Disturbance Control Standard	A NERC-defined metric measuring the ability of a control area to return area control error (ACE) either to zero or to its predisturbance level after a disturbance such as a generator or transmission loss.

Eastern Prevailing Time (EPT)	Eastern Prevailing Time (EPT) is equivalent to Eastern Standard Time (EST) or Eastern Daylight Time (EDT) as is in effect from time to time.
Eastern Region	Defined region for purposes of allocating balancing operating reserve charges. Includes the BGE, Dominion, PENELEC, Pepco, Met-Ed, PPL, JCPL, PECO, DPL, PSEG, and RECO transmission zones.
Economic generation	Units producing energy at an offer price less than or equal to LMP.
End-use customer	Any customer purchasing electricity at retail.
Equivalent availability factor (EAF)	The proportion of hours in a year that a unit is available to generate at full capacity.
Equivalent demand forced outage rate (EFORd)	A measure of the probability that a generating unit will not be available due to forced outages or forced deratings when there is a demand on the unit to generate.
Equivalent forced outage factor (EFOF)	The proportion of hours in a year that a unit is unavailable because of forced outages.
Equivalent maintenance outage factor (EMOF)	The proportion of hours in a year that a unit is unavailable because of maintenance outages.
Equivalent planned outage factor (EPOF)	The proportion of hours in a year that a unit is unavailable because of planned outages.
External resource	A generation resource located outside metered boundaries of the PJM RTO.
Financial Transmission Right (FTR)	A financial instrument entitling the holder to receive revenues based on transmission congestion measured as hourly energy LMP differences in the PJM Day-Ahead Energy Market across a specific path.
Firm Point-to-Point Transmission Service	Transmission Service that is reserved and/or scheduled between specified Points of Receipt and Delivery.
Firm Transmission Service	Transmission service that is intended to be available at all times to the maximum extent practicable, subject to an emergency, and unanticipated failure of a facility, or other event beyond the control of the owner or operator of the facility, or the Office of the Interconnection.

Fixed Demand Bid	Bid to purchase a defined MW level of energy, regardless of LMP.
Fixed Resource Requirement (FRR)	An alternative method for a party to satisfy its obligation to provide Unforced Capacity. Allows an LSE to avoid direct participation in the RPM Auctions by meeting their fixed capacity resource requirement using internally owned capacity resources
Flowgate	A transmission facility or group of facilities that consist of the total interface between control areas, a partial interface, or an interface within a control area.
Frequently mitigated unit (FMU)	A unit that was offer-capped for more than a defined proportion of its real-time run hours in the most recent 12-month period. FMU thresholds are 60 percent, 70 percent and 80 percent of run hours. Such units are permitted a defined adder to their cost-based offers in place of the usual 10 percent adder.
Generation Control Area (GCA) and Load Control Area (LCA)	Designations used on a NERC Tag to describe the balancing authority where the energy is generated (GCA) and the balancing authority where the load is served (LCA). Note: the terms "Control Area" in these acronyms are legacy terms for balancing authority, and are expected to be changed in the future.
Generator deviations	Hourly deviations in the generator category, equal to the difference between a unit's cleared day-ahead generation, and a unit's hourly, integrated real-time generation.
Generation Offers	Schedules of MW offered and the corresponding offer price.
Generation owner	A PJM member that owns or leases, with rights equivalent to ownership, facilities for generation of electric energy that are located within PJM.
Gross export volume (energy)	The sum of all export transaction volume (MWh).
Gross import volume (energy)	The sum of all import transaction volume (MWh).
Gigawatt (GW)	A unit of power equal to 1,000 megawatts.
Gigawatt-day	One GW of energy flow or capacity for one day.
Gigawatt-hour (GWh)	One GWh is a gigawatt produced or consumed for one hour.

Herfindahl-Hirschman Index (HHI)	HHI is calculated as the sum of the squares of the market share percentages of all firms in a market.
Hertz (Hz)	Electricity system frequency is measured in hertz.
HRSG	Heat recovery steam generator. An air-to-steam heat exchanger.
Increment offers (INC)	Financial offers in the Day-Ahead Energy Market to supply specified amounts of MW at, or above, a given price.
Incremental Auction	Reliability Pricing Model (RPM) auction to allow for an incremental procurement of resource commitments to satisfy an increase in the region's unforced capacity obligation due to a load forecast increase or a decrease in the amount of resource commitments due to a resource cancellation, delay, derating, EFORd increase, or decrease in the nominated value of a Planned Demand Resource.
Inframarginal unit	A unit that is operating, with an accepted offer that is less than the clearing price.
Installed capacity	Installed capacity is the as-tested maximum net dependable capability of the generator, measured in MW.
Load	Demand for electricity at a given time.
Load Management	Previously known as ALM (Active Load Management). ALM was a term that PJM used prior to the implementation of RPM where end use customer load could be reduced at the request of PJM. The ability to reduce metered load, either manually by the customer, after a request from the resource provider which holds the Load management rights or its agent (for Contractually Interruptible), or automatically in response to a communication signal from the resource provider which holds the Load management rights or its agent (for Direct Load Control).
Load-serving entity (LSE)	Load-serving entities provide electricity to retail customers. Load-serving entities include traditional distribution utilities and new entrants into the competitive power market.
Locational Deliverability Area (LDA)	Sub-regions used to evaluate locational constraints. LDAs include EDC zones, sub-zones, and combination of zones.

Marginal unit	The last, highest cost, generation unit to supply power under a merit order dispatch system.
Market-clearing price	The price that is paid by all load and paid to all suppliers.
Market participant	A PJM market participant can be a market supplier, a market buyer or both. Market buyers and market sellers are members that have met creditworthiness standards as established by the PJM Office of the Interconnection.
Market user interface	A thin client application allowing generation sellers to provide and to view generation data, including bids, unit status and market results.
Maximum daily starts	The maximum number of times a unit can start in a day. An operating parameter incorporated in a unit's schedule.
Maximum weekly starts	The maximum number of times a unit can start in a week. An operating parameter incorporated in a unit's schedule.
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.
Minimum down time	The minimum amount of time that a unit has to stay off, or "down," before starting again. An operating parameter incorporated in a unit's schedule.
Minimum run time	The minimum amount of time that a unit has to stay on before shutting down. An operating parameter incorporated in a unit's schedule.
Monthly CCM	The capacity credits cleared each month through the PJM Monthly Capacity Credit Market (CCM).
Multimonthly CCM	The capacity credits cleared through PJM Multimonthly Capacity Credit Market (CCM).

Net excess (capacity)	The net of gross excess and gross deficiency, therefore the total PJM capacity resources in excess of the sum of load-serving entities' obligations.
Net exchange (capacity)	Capacity imports less exports.
Net interchange (energy)	Gross import volume less gross export volume in MWh.
Network Transmission Service	Transmission service that is for the sole purpose of serving network load. Network transmission service is only available to network customers.
Noneconomic generation	Units producing energy at an offer price greater than the LMP.
Non-Firm Transmission Service	Point-to-point transmission service under the PJM tariff that is reserved and scheduled on an as available basis and is subject to curtailment or interruption. Non-firm point to point transmission service is available on a stand-alone basis for periods ranging from one hour to one month.
North American Electric Reliability Council (NERC)	A voluntary organization of U.S. and Canadian utilities and power pools established to assure coordinated operation of the interconnected transmission systems.
Off peak	For the PJM Energy Market, off-peak periods are all NERC holidays (i.e., New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, Christmas Day) and weekend hours plus weekdays from the hour ending at midnight until the hour ending at 0700.
On peak	For the PJM Energy Market, on-peak periods are weekdays, except NERC holidays (i.e., New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, Christmas Day) from the hour ending at 0800 until the hour ending at 2300.
Opportunity cost	In general, the value of the opportunity foregone when a specific action is taken. In the ancillary services markets, the difference in compensation from the Energy Market between what a unit receives when providing regulation or synchronized reserve and what it would have received had it provided energy instead.

Parameter-limited schedule	A schedule for a unit that has parameters that are used when the unit fails the three pivotal supplier test, or in a maximum generation emergency event. These parameters are pre-determined by the MMU based on unit class, unless an exception is otherwise granted.
PJM member	Any entity that has completed an application and satisfies the requirements of the PJM Board of Managers to conduct business with PJM, including transmission owners, generating entities, load-serving entities and marketers.
PJM planning year	The calendar period from June 1 through May 31.
Point of Receipt (POR) and Point of Delivery (POD)	Designations used on a transmission reservation. The designations, when combined, determine the transmission reservations' market path.
Pool-scheduled resource	A generating resource that the seller has turned over to PJM for scheduling and control.
Price duration curve	graphic representation of the percent of hours that a system's price was at or below a given level during the year.
Price-sensitive bid	Purchases of a defined MW level of energy only up to a specified LMP. Above that LMP, the load bid is zero.
Primary operating interfaces	Primary operating interfaces are typically defined by a cross section of transmission paths or single facilities which affect a wide geographic area. These interfaces are modeled as constraints whose operating limits are respected in performing dispatch operations.
Ramp-limited desired (MW)	The achievable MW based on the UDS requested ramp rate.
Regional Transmission Expansion Planning (RTEP) Protocol	The process by which PJM recommends specific transmission facility enhancements and expansions based on reliability and economic criteria.

Reliability*First* Corporation	Reliability*First* Corporation (RFC) began operation January 1, 2006, as the successor to three other reliability organizations: the Mid-Atlantic Area Council (MAAC), the East Central Area Coordination Agreement (ECAR), and the Mid-American Interconnected Network (MAIN). PJM is registered with RFC to comply with its reliability standards for balancing authority (BA), planning coordinator (PC), reliability coordinator (RC), resource planner (RP), transmission operator (TOP), transmission planner (TP) and transmission service provider (TSP).
Reliability Pricing Model (RPM)	PJM's resource adequacy construct. The purpose of RPM is to develop a long term pricing signal for capacity resources and LSE obligations that is consistent with the PJM Regional Transmission Expansion Planning Process (RTEPP). RPM adds stability and a locational nature to the pricing signal for capacity.
Selective catalytic reduction (SCR)	NO_x 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.
Short-Term Resource Procurement Target	The Short-Term Resource Procurement Target is equal to 2.5% of the PJM Region Reliability Requirement determined for such Base Residual Auction, 2% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction for purposes of the First Incremental Auction, and 1.5% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction for purposes of the Second Incremental Auction. The stated rationale for this administrative reduction in demand is to permit short lead time resource procurement in later auctions for the delivery year.
Sources and sinks	Sources are the origins or the injection end of a transmission transaction. Sinks are the destinations or the withdrawal end of a transaction.

Spot Import Transmission Service	Transmission service introduced as an option for non-load serving entities to offer into the PJM spot market at the border/interface as price takers.Spot market Transactions made in the Real-Time and Day-Ahead Energy Market at hourly LMP.
Static Var compensator	A static Var compensator (SVC) is an electrical device for providing fast-acting, reactive power compensation on high-voltage electricity transmission networks.
Summer Net Capability	The Summer Net Capability of each unit or station shall be based on summer conditions and on the power factor level normally expected for that unit or station at the time of the PJM summer peak load. Summer conditions shall reflect the 50% probability of occurrence (approximated by the mean) of temperature and humidity conditions of the time of the PJM summer peak load. Conditions shall be based on local weather bureau records of the past 15 years, updated at 5 year intervals. When local weather records are not available, the values shall be estimated from the best data available. For steam units, summer conditions shall mean, where applicable, the probable intake water temperature of once-through or open cooling systems experienced in June, July, and August at the time of the PJM peak each weekday. For combustion turbine units, summer conditions shall mean, where applicable, the probable ambient air temperature and humidity condition experienced at the unit location at the time of the annual summer PJM peak. The determination of the Summer Net Capability of hydro and pumped storage units shall be based on operational data or test results taken once each year at any time during the year. The same operational data or test results can be used for the determination of the Winter Net Capability. For combined-cycle units, summer conditions shall mean where applicable, the probable intake water temperature of once-through or open cooling systems experienced in June, July, and August at the time of the PJM peak each weekday, and the probable ambient air temperature and humidity condition experienced at the unit location at the time of the annual summer PJM peak.

Supply deviations	Hourly deviations in the supply category, equal to the difference between the sum of cleared increment offers, day-ahead purchases, and day-ahead imports, to the sum of real-time purchases and real-time imports.
Synchronized reserve	Reserve capability which is required in order to enable an area to restore its tie lines to the pre-contingency state within 10 minutes of a contingency that causes an imbalance between load and generation. During normal operation, these reserves must be provided by increasing energy output on electrically synchronized equipment, by reducing load on pumped storage hydroelectric facilities or by reducing the demand by demand-side resources. During system restoration, customer load may be classified as synchronized reserve.
System installed capacity	System total installed capacity measures the sum of the installed capacity (in installed, not unforced, terms) from all internal and qualified external resources designated as PJM capacity resources.
System lambda	The cost to the PJM system of generating the next unit of output.
Temperature-humidity index (THI)	A temperature-humidity index (THI) gives a single, numerical value reflecting the outdoor atmospheric conditions of temperature and humidity as a measure of comfort (or discomfort) during warm weather. THI is defined as: THI = $T_d - (0.55 - 0.55RH) * (T_d - 58)$ if T_d is > 58; else THI= T_d (where T_d is the dry-bulb temperature and RH is the percentage of relative humidity.)
Transmission Adequacy and Reliability Assessment (TARA)	An analysis tool that can calculate generation to load impacts. This tool is used to facilitate loop flow analysis across the Eastern Interconnection.
Turn down ratio	The ratio of dispatchable megawatts on a unit's schedule. Calculated by a unit's economic maximum MW divided by its economic minimum MW. An operating parameter of a unit's schedule.
Unforced capacity	Installed capacity adjusted by forced outage rates.
Western region	Defined region for purposes of allocating balancing operating reserve charges. Includes the AEP, AP, ComEd, DLCO, and DAY transmission zones.

Wheel-through	An energy transaction flowing through a transmission grid whose origination and destination are outside of the transmission grid.
Winter Weather Parameter (WWP)	WWP is wind speed adjusted temperature. WWP is defined as: WWP = T_d - (0.5 * (WIND -10) if WIND > 10 mph; WWP = T_d if WIND <= 10 mph (where T_d is the dry-bulb temperature and WIND is the wind speed.)
Zone	See “Control zone” (above).

APPENDIX O – LIST OF ACRONYMS

ACE	Area control error
ACR	Avoidable cost rate
AECI	Associated Electric Cooperative Inc.
AECO	Atlantic City Electric Company
AEG	Alliant Energy Corporation
AEP	American Electric Power Company, Inc.
AGC	Automatic generation control
ALM	Active load management
ALTE	Eastern Alliant Energy Corporation
ALTW	Western Alliant Energy Corporation
AMIL	Ameren - Illinois
AMRN	Ameren
AP	Allegheny Power Company
APIR	Avoidable Project Investment Recovery
ARR	Auction Revenue Right
ARS	Automatic reserve sharing
ATC	Available transfer capability
AU	Associated unit
BA	Balancing authority
BAAL	Balancing authority ACE limit
BGE	Baltimore Gas and Electric Company
BGS	Basic generation service
BME	Balancing market evaluation

BRA	Base Residual Auction
Btu	British thermal unit
C&I	Commercial and industrial customers
CAIR	Clean Air Interstate Rule
CAISO	California Independent System Operator
CBL	Customer base line
CC	Combined cycle
CCM	Capacity Credit Market
CDR	Capacity deficiency rate
CDTF	Cost Development Task Force
CETL	Capacity emergency transfer limit
CETO	Capacity emergency transfer objective
CF	Coordinated flowgate under the Joint Operating Agreement between PJM and the Midwest Independent Transmission System Operator, Inc.
CILC	Central Illinois Light Company Interface
CILCO	Central Illinois Light Company
CIN	Cinergy Corporation
CLMP	Congestion component of LMP
CMP	Congestion management process
CMR	Congestion Management Report
ComEd	The Commonwealth Edison Company
Con Edison	The Consolidated Edison Company
CONE	Cost of new entry
CP	Pulverized coal-fired generator

CPL	Carolina Power & Light Company
CPS	Control performance standard
CRC	Central Repository for Curtailments
CSP	Curtailment service provider
CT	Combustion turbine
CTR	Capacity transfer right
DASR	Day-Ahead Scheduling Reserve
DAY	The Dayton Power & Light Company
DC	Direct current
DCS	Disturbance control standard
DEC	Decrement bid
DFAX	Distribution factor
DL	Diesel
DLCO	Duquesne Light Company
DPL	Delmarva Power & Light Company
DPLN	Delmarva Peninsula north
DPLS	Delmarva Peninsula south
DR	Demand response
DSR	Demand-side response
DUK	Duke Energy Corporation
EAF	Equivalent availability factor
ECAR	East Central Area Reliability Council
EDC	Electricity distribution company
EDT	Eastern Daylight Time

EE	Energy Efficiency
EEA	Emergency energy alert
EES	Enhanced Energy Scheduler
EFOF	Equivalent forced outage factor
EFORd	Equivalent demand forced outage rate
EHV	Extra-high-voltage
EKPC	East Kentucky Power Cooperative, Inc.
EMAAC	Eastern Mid-Atlantic Area Council
EMOF	Equivalent maintenance outage factor
EMS	Energy management system
EPOF	Equivalent planned outage factor
EPT	Eastern Prevailing Time
EST	Eastern Standard Time
ExGen	Exelon Generation Company, L.L.C.
FE	FirstEnergy Corp.
FERC	The United States Federal Energy Regulatory Commission
FFE	Firm flow entitlement
FMU	Frequently mitigated unit
FPA	Federal Power Act
FPR	Forecast pool requirement
FRR	Fixed resource requirement
FTR	Financial Transmission Right
GCA	Generation control area
GE	General Electric Company

GW	Gigawatt
GWh	Gigawatt-hour
HHI	Herfindahl-Hirschman Index
HRSG	Heat recovery steam generator
HVDC	High-voltage direct current
Hz	Hertz
IA	RPM Incremental Auction
ICAP	Installed capacity
ICCP	Inter-Control Center Protocol
IDC	Interchange distribution calculator
IESO	Ontario Independent Electricity System Operator
ILR	Interruptible load for reliability
INC	Increment offer
IP	Illinois Power Company
IPL	Indianapolis Power & Light Company
IPP	Independent power producer
IRM	Installed reserve margin
IRR	Internal rate of return
ISA	Interconnection service agreement
ISO	Independent system operator
JCPL	Jersey Central Power & Light Company
JOA	Joint operating agreement
JOU	Jointly owned units
JRCA	Joint Reliability Coordination Agreement

LAS	PJM Load Analysis Subcommittee
LCA	Load control area
LDA	Locational deliverability area
LGEE	LG&E Energy, L.L.C.
LIND	Linden Variable Frequency Transformer (VFT)
LM	Load management
LMP	Locational marginal price
LOC	Lost opportunity cost
LSE	Load-serving entity
MAAC	Mid-Atlantic Area Council
MAAC+APS	Mid-Atlantic Area Council plus the Allegheny Power System
MACRS	Modified accelerated cost recovery schedule
MAIN	Mid-America Interconnected Network, Inc.
MAPP	Mid-Continent Area Power Pool
MCP	Market-clearing price
MDS	Maximum daily starts
MDT	Minimum down time
MEC	MidAmerican Energy Company
MECS	Michigan Electric Coordinated System
Met-Ed	Metropolitan Edison Company
MICHFE	The pricing point for the Michigan Electric Coordinated System and FirstEnergy control areas
MIL	Mandatory interruptible load
MIS	Market information system

MISO	Midwest Independent Transmission System Operator, Inc.
MMU	PJM Market Monitoring Unit
Mon Power	Monongahela Power
MP	Market participant
MRC	Markets and reliability committee
MRT	Minimum run time
MUI	Market user interface
MW	Megawatt
MWh	Megawatt-hour
MWS	Maximum weekly starts
NAESB	North American Energy Standards Board
NCMPA	North Carolina Municipal Power Agency
NEPT	Neptune DC line
NERC	North American Electric Reliability Council
NICA	Northern Illinois Control Area
NIPSCO	Northern Indiana Public Service Company
NNL	Network and native load
NO_x	Nitrogen oxides
NUG	Non-utility generator
NYISO	New York Independent System Operator
OA	Amended and Restated Operating Agreement of PJM Interconnection, L.L.C.
OASIS	Open Access Same-Time Information System
OATI	Open Access Technology International, Inc.
OATT	PJM Open Access Transmission Tariff

ODEC	Old Dominion Electric Cooperative
OEM	Original equipment manufacturer
OI	PJM Office of the Interconnection
Ontario IESO	Ontario Independent Electricity System Operator
OVEC	Ohio Valley Electric Corporation
PAR	Phase angle regulator
PE	PECO zone
PEC	Progress Energy Carolinas, Inc.
PECO	PECO Energy Company
PENELEC	Pennsylvania Electric Company
Pepco	Formerly Potomac Electric Power Company or PEPCO
PJM	PJM Interconnection, L.L.C.
PJM/AEPNI	The interface between the American Electric Power Control Zone and Northern Illinois
PJM/AEPPJM	The interface between the American Electric Power Control Zone and PJM
PJM/AEPVP	The single interface pricing point formed in March 2003 from the combination of two previous interface pricing points: PJM/American Electric Power Company, Inc. and PJM/Dominion Resources, Inc.
PJM/AEPVPEXP	The export direction of the PJM/AEPVP interface pricing point
PJM/AEPVPIMP	The import direction of the PJM/AEPVP interface pricing point
PJM/ALTE	The interface between PJM and the eastern portion of the Alliant Energy Corporation’s control area
PJM/ALTW	The interface between PJM and the western portion of the Alliant Energy Corporation’s control area

PJM/AMRN	The interface between PJM and the Ameren Corporation's control area
PJM/CILC	The interface between PJM and the Central Illinois Light Company's control area
PJM/CIN	The interface between PJM and the Cinergy Corporation's control area
PJM/CPLE	The interface between PJM and the eastern portion of the Carolina Power & Light Company's control area
PJM/CPLW	The interface between PJM and the western portion of the Carolina Power & Light Company's control area
PJM/CWPL	The interface between PJM and the City Water, Light & Power's (City of Springfield, IL) control area
PJM/DLCO	The interface between PJM and the Duquesne Light Company's control area
PJM/DUK	The interface between PJM and the Duke Energy Corp.'s control area
PJM/EKPC	The interface between PJM and the Eastern Kentucky Power Corporation's control area
PJM/FE	The interface between PJM and the FirstEnergy Corp.'s control area
PJMICC	PJM Industrial Customer Coalition
PJM/IP	The interface between PJM and the Illinois Power Company's control area
PJM/IPL	The interface between PJM and the Indianapolis Power & Light Company's control area
PJM/LGEE	The interface between PJM and the Louisville Gas and Electric Company's control area
PJM/LIND	The interface between PJM and the New York System Operator over the Linden VFT line
PJM/MEC	The interface between PJM and MidAmerican Energy Company's control area

PJM/MECS	The interface between PJM and the Michigan Electric Coordinated System's control area
PJM/MISO	The interface between PJM and the Midwest Independent System Operator
PJM/NEPT	The interface between PJM and the New York Independent System Operator over the Neptune DC line
PJM/NIPS	The interface between PJM and the Northern Indiana Public Service Company's control area
PJM/NYIS	The interface between PJM and the New York Independent System Operator
PJM/Ontario IESO	PJM/Ontario IESO pricing point
PJM/OVEC	The interface between PJM and the Ohio Valley Electric Corporation's control area
PJM/TVA	The interface between PJM and the Tennessee Valley Authority's control area
PJM/VAP	The interface between PJM and the Dominion Virginia Power's control area
PJM/WEC	The interface between PJM and the Wisconsin Energy Corporation's control area
PLS	Parameter limited schedule
PMSS	Preliminary market structure screen
PNNE	PENELEC's northeastern subarea
PNNW	PENELEC's northwestern subarea
POD	Point of delivery
POR	Point of receipt
PPL	PPL Electric Utilities Corporation
PSE&G	Public Service Electric and Gas Company (a wholly owned subsidiary of PSEG)
PSEG	Public Service Enterprise Group

PSN	PSEG north
PSNC	PSEG northcentral
RAA	Reliability Assurance Agreement among Load-Serving Entities
RCIS	Reliability Coordinator Information System
RECO	Rockland Electric Company zone
RFC	Reliability*First* Corporation
RLD (MW)	Ramp-limited desired (Megawatts)
RLR	Retail load responsibility
RMCP	Regulation market-clearing price
RMR	Reliability Must Run
RPM	Reliability Pricing Model
RSI	Residual supply index
RSI_x	Residual supply index, using “x” pivotal suppliers
RTC	Real-time commitment
RTEP	Regional Transmission Expansion Plan
RTO	Regional transmission organization
SCE&G	South Carolina Energy and Gas
SCPA	Southcentral Pennsylvania subarea
SCR	Selective catalytic reduction
SEPA	Southeast Power Administration
SEPJM	Southeastern PJM subarea
SERC	Southeastern Electric Reliability Council
SFT	Simultaneous feasibility test
SMECO	Southern Maryland Electric Cooperative

SMP	System marginal price
SNJ	Southern New Jersey
SO_2	Sulfur dioxide
SOUTHEXP	South Export pricing point
SOUTHIMP	South Import pricing point
SPP	Southwest Power Pool, Inc.
SPREGO	Synchronized reserve and regulation optimizer (market-clearing software)
SRMCP	Synchronized reserve market-clearing price
STD	Standard deviation
SVC	Static Var compensator
SWMAAC	Southwestern Mid-Atlantic Area Council
TARA	Transmission adequacy and reliability assessment
TDR	Turn down ratio
TEAC	Transmission Expansion Advisory Committee
THI	Temperature-humidity index
TLR	Transmission loading relief
TPS	Three pivotal supplier
TPSTF	Three Pivotal Supplier Task Force
TVA	Tennessee Valley Authority
UCAP	Unforced capacity
UDS	Unit dispatch system
UGI	UGI Utilities, Inc.
UPF	Unit participation factor
VACAR	Virginia and Carolinas Area

VAP	Dominion Virginia Power
VFT	Variable frequency transformer
VOM	Variable operation and maintenance expense
VRR	Variable resource requirement
WEC	Wisconsin Energy Corporation
WLR	Wholesale load responsibility
WPC	Willing to pay congestion