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October 17, 2017

The Honorable Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: PJM Interconnection, L.L.C., Docket No. ER18-86-000
Proposed Revisions On Allocating Uplift To Virtual Transactions

Dear Secretary Bose:

PJM Interconnection, L.L.C. ("PJM"), pursuant to section 205 of the Federal Power Act ("FPA"), 16 U.S.C. § 824d, and the Federal Energy Regulatory Commission's ("Commission") Regulations, 18 C.F.R. Part 35, hereby submits proposed revisions to the Amended and Restated Operating Agreement of PJM Interconnection L.L.C. ("Operating Agreement"), Schedule 1, and the identical provisions of PJM Open Access Transmission Tariff ("Tariff"), Attachment K-Appendix[1] to more equitably allocate day-ahead Operating Reserves[2] and balancing Operating Reserves (commonly referred to as "uplift"[3]) to Virtual Transactions[4] and to refine the methodology used to calculate Operating Reserve credits paid to Market Participants.[5] Further,

[1] Because Tariff, Attachment K-Appendix and Operating Agreement, Schedule 1 are identical, for convenience, PJM will reference only the Operating Agreement, Schedule 1 throughout this letter.

[2] While PJM's governing documents generally refer to these Operating Reserves as "Operating Reserves in the Day-ahead Energy Market," PJM will refer to them as "day-ahead Operating Reserves," herein for convenience.

[3] "Uplift" generally refers to any payments from PJM to Market Participants that are not directly attributable to Locational Marginal Price. While under this broad definition there are other forms of uplift payments in PJM, *e.g.* lost opportunity credits and credits paid to Black Start resources, this filing only relates to Operating Reserves credits. Therefore, all references to "uplift" herein relate solely to Operating Reserves credits.

[4] All capitalized terms that are not otherwise defined herein shall have the same meaning as they are defined in the Tariff, Operating Agreement or the Reliability Assurance Agreement among Load Serving Entities in the PJM Region ("RAA").

[5] Operating Reserve credits are the technical term PJM's governing documents use to describe uplift payments.

in accordance with the notice requirement in section 35.3(a)(1) of the Commission's Regulations, PJM respectfully asks the Commission to issue an order accepting these proposed revisions on or before December 18, 2017, with an effective date of April 1, 2018.[6]

I. BACKGROUND

A. Procedural Background

PJM and its stakeholders have been discussing uplift in PJM's energy markets since May 2013 when the Energy Market Uplift Senior Task Force ("EMUSTF") was first formed. This filing, along with PJM's filing related to reducing the number of eligible Virtual Transaction bidding points being submitted concurrently with this filing, represent the culmination of PJM stakeholders' efforts over the past four years to reduce uplift in PJM's energy market, allocate the costs associated with uplift in a more equitable manner, and ensure to better price formation in PJM's energy markets.[7]

After over a year of discussion, the Commission initiated a separate proceeding pursuant to section 206 of the FPA in August 2014 to "examine how uplift is, or should be, allocated to all virtual transactions,"[8] and held a technical conference on January 7, 2015.[9] After participating in the Commission's technical conference, PJM filed post technical conference comments and

[6] While PJM's Members Committee approved the enclosed revisions on February 23, 2017, with a sector-weighted vote of 4.16 out of 5.0 in favor, PJM delayed submitting this filing given the fact the Commission lacked a quorum between February 4, 2017 and August 10, 2017.

[7] In addition to these two filings, in 2015 PJM modified its methodology used to credit Market Sellers of certain types of generating units for lost opportunity costs – a filing which also arose from the EMUSTF. *See PJM Interconnection, L.L.C.*, Docket No. ER15-1966-000 (Jun. 23, 2015) (accepted by the Commission in *PJM Interconnection, L.L.C.*, 152 FERC ¶ 61,165 (2015)).

[8] *See PJM Interconnection, L.L.C.*, 148 FERC ¶ 61,144, at P 13 (2014) ("Order Establishing 206 Proceeding"). The Commission also examined PJM's application of the FTR Forfeiture Rule to Virtual Transactions in the same proceeding, however that issue is not relevant to the subject matter of this filing and will not be discussed herein.

[9] *See e.g. PJM Interconnection, L.L.C.*, Notice of Technical Conference, Docket No. EL14-37-000 (Oct. 31, 2014).

provided an in-depth explanation for why Up-to Congestion Transactions[10] ("UTCs") should be allocated uplift in the same way that uplift is allocated to Increment Offers[11] ("INCs") and Decrement Bids[12] ("DECs").[13]

In its Order Establishing 206 Proceeding the Commission stated that it expected to "render a decision within five months of the submission of post-technical conference pleadings."[14] PJM submitted its post-technical conference comments on May 29, 2015. While awaiting Commission action, PJM staff conducted additional analyses and issued a detailed report on Virtual Transactions in PJM in October 2015, which recommended, among other things, that UTCs should be allocated uplift in the same way uplift is allocated to INCs and DECs.[15]

Still awaiting substantive Commission action following the Order Establishing 206 Proceeding, in February of 2016, PJM and the Independent Market Monitor for PJM ("IMM")

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[10] "Up-to Congestion Transaction" shall mean a type of Virtual Transaction that combines an offer to sell energy at a source, with a bid to buy the same megawatt quantity of energy at a sink where such transaction specifies the maximum difference between the Locational Marginal Prices at the source and sink. Operating Agreement, Schedule 1, section 1.10.1A(c-1).

[11] "Increment Offers" shall mean a type of Virtual Transaction that is an offer to sell energy at a specified location in the Day-ahead Energy Market. A cleared Increment Offer results in scheduled generation at the specified location in the Day-ahead Energy Market. *See* Operating Agreement, section 1 (Definitions). INCs are a "supply side" or "energy-injection" transaction.

[12] "Decrement Bid" shall mean a type of Virtual Transaction that is a bid to purchase energy at a specified location in the Day-ahead Energy Market. A cleared Decrement Bid results in scheduled load at the specified location in the Day-ahead Energy Market. *Id.* DECs are a "demand side" or "energy-withdrawal" transaction.

[13] *See PJM Interconnection, L.L.C.*, Comments of PJM Interconnection, L.L.C., Docket No. EL14-37-000, at 9-11 (May 29, 2015) ("PJM Post-Technical Conference Comments")

[14] *See* Order Establishing 206 Proceeding at P 16.

[15] *See e.g.* PJM Interconnection, L.L.C., *Virtual Transactions in the PJM Energy Markets*, at 48 (Oct. 12, 2015) (available at http://www.pjm.com/~/media/committees-groups/committees/mc/20151019-webinar/20151019-item-02-virtual-transactions-in-the-pjm-energy-markets-whitepaper.ashx) ("Virtual Transactions Whitepaper") (attached hereto as Attachment C).

filed a joint letter requesting prompt Commission action.[16] PJM's EMUSTF nevertheless proceeded to address the issues and endorsed the enclosed Tariff revisions in January, 2017, allocating uplift to UTCs in the same manner as uplift is currently allocated to INCs and DECs.

As the other PJM committees of stakeholders were reviewing the revisions from the EMUSTF, the Commission issued the Uplift NOPR on January 19, 2017.[17] Notwithstanding the pendency of the NOPR, PJM respectfully asks the Commission to accept PJM's proposal herein as it will greatly improve the current allocation of uplift. As will be described below in section II, the revisions proposed in this filing will more equitably allocate uplift to all Virtual Transactions by allocating uplift to UTCs in the same way that uplift is currently allocated to INCs and DECs. While UTCs are not currently allocated uplift, this treatment is no longer just and reasonable, and may be unduly discriminatory. Moreover, as described below in section IV, PJM is proposing to revise the manner in which it calculates Operating Reserve credits because under certain circumstances, the current calculation results in Market Participants not being made whole for following PJM's instructions as intended, but actually losing money. For the reasons described herein, the proposed revisions are just and reasonable and should be accepted by the Commission.

B. Description of Virtual Transactions

Virtual Transactions are sets of bids and offers submitted in the Day-ahead Energy Market that take financial positions in that market without the intent of delivering or consuming

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[16] *See PJM Interconnection, L.L.C.*, Joint PJM/IMM Informational Letter, Docket No. EL14-37-000 (Feb. 11, 2016).

[17] *See Uplift Cost Allocation and Transparency in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 158 FERC ¶ 61,047 (2017) ("Uplift NOPR").

physical power in the Real-time Energy Market. In PJM, Virtual Transactions include INCs, DECs and UTCs.

An INC is an offer to sell electricity in the Day-Ahead market at a stated price at a particular location (*i.e.*, node). A DEC is an offer to buy electricity in the Day-Ahead market at a stated price at a node. A UTC is a bid to purchase transmission congestion and losses in the Day-Ahead market at a stated price spread between two particular nodes.[18]

Such transactions can be a valuable supplement to a two-settlement market like PJM's (*i.e.* an electricity market which has separate Day-ahead and Real-time Energy Market). That is because all cleared schedules in the Day-ahead Energy Market are financial contracts that can be settled at real-time prices rather than through physical delivery of energy. As a result, Market Participants without physical assets (*i.e.*, financial participants) can participate with asset owners and Load Serving Entities in PJM's energy markets using Virtual Transactions.[19] Allowing Virtual Transactions to participate in the Day-ahead Energy Markets provides some market efficiencies including those associated with increased liquidity, improved price formation, market-based redistribution of risk, and mitigation of market power.

However, Virtual Transactions can have negative impacts on the market and certain types of transaction activities, while profitable for traders, do not bring efficiency and can even degrade market operation.[20] When used in certain ways, these transactions profit from the market without adding commensurate benefit, skew transmission flows and congestion patterns

[18] See notes 10-12, supra.

[19] *See e.g.* Virtual Transactions Whitepaper at 2.

[20] *See e.g., Id.*

in a manner inconsistent with real-time operations, and, in large volumes, can significantly degrade the performance of the Day-ahead Energy Market.[21] Therefore, PJM is proposing the enclosed revisions, along with the revisions related to reducing the number of eligible Virtual Transaction bidding points being filed concurrently with this filing, in order to improve market outcomes and operations for all Market Participants.

II. UPLIFT ALLOCATION

A. Description of Uplift and PJM's Current Uplift Allocation Rules for Virtual Transactions

Uplift is paid to Market Participants under specified conditions to ensure that resources do not operate at PJM's direction at a financial loss, and is one of the incentives for Market Participants owning supply resources to offer their energy in PJM's energy markets at marginal cost and to operate their units at the direction of PJM dispatchers. Uplift is allocated to different classes of Market Participants depending on several factors, including whether the uplift is attributable to actions related to the Day-ahead Energy Market or Real-time Energy Market.[22] Relevant to this filing, INCs and DECs are currently allocated uplift in PJM, however UTCs are not. As discussed in more detail herein, this has led to inequitable results that must be corrected. Accordingly, PJM proposes to allocate uplift to UTCs in the same manner in which uplift is allocated in INCs and DECs.

Under PJM's current market rules, uplift is allocated in one of two ways: First, all withdrawals in the Day-ahead Energy Market are allocated an equal share of the uplift incurred

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[21] *See, e.g., Id.*

[22] For a more in depth description of how uplift is allocated in PJM, *see Price Formation in Energy and Ancillary Services Markets Operated by Regional Transmission Organizations and Independent System Operators*, PJM Interconnection, L.L.C. Report on Price Formation Issues, Docket No. AD14-14-000, at 28-32 (Feb. 17, 2016) ("PJM Price Formation Report").

in the Day-ahead Energy Market. Day-ahead withdrawals include fixed Demand Bids, cleared price sensitive Demand Bids and DECs, and Export Transactions.[23] Second, uplift is allocated to transactions which deviate between the day-ahead and real-time positions.[24] Based on the set of rules that are in practice today, a DEC transaction receives a share of the uplift from the Day-ahead Energy Market because it is essentially a load in the Day-ahead Energy Market and it receives an allocation of real-time uplift because it is deviating from its day-ahead position. An INC only receives an allocation of real-time uplift.

B. UTCs Should also Receive an Allocation of Uplift

Currently, in PJM, UTCs are not allocated any uplift. This is because UTCs did not evolve into a purely financial product until after the last major set of uplift allocation reforms in PJM in 2008.[25] Originally these transactions were created so that Market Participants wheeling power through PJM in real-time could hedge against real-time congestion. At that time, submitting a UTC into the Day-ahead Energy Market required a transmission service reservation which added transaction cost. Because the Market Participant submitting the UTC had to incur the cost of procuring that service, the transactions were used as hedges for physical wheel transactions, not as Virtual Transactions. Over time and through a series of market rule changes, including ones that were responsive to an inappropriate use of the product to collect marginal loss over-collection revenues,[26] the transmission service reservation requirement to submit a

[23] OA, Schedule 1, section 3.2.3(d).

[24] For example, a cleared 10 MW INC in the Day-ahead Energy Market that has a 0 megawatt position in the Real-time Energy Market is allocated a share of the real-time uplift charges because it is considered a deviation from the day-ahead position. *See e.g.* OA, Schedule 1, section 3.2.3(h); PJM Post-Technical Conference Comments at 9.

[25] *See, e.g.*, *Id.* at 9-10.

[26] *See, e.g.*, *PJM Interconnection, L.L.C.*, 132 FERC ¶ 61,244 (2010).

UTC was removed and the product evolved into a purely financial one used to arbitrage day-ahead and real-time price spreads.

The EMUSTF is the first time PJM stakeholders have convened to discuss uplift reforms since the fundamental change in the UTC product. Given the fact UTCs are a Virtual Transaction that is not allocated uplift, they cost less per transaction compared to INCs and DECs. Additionally, because a UTC settles purely on congestion and losses and not energy, a UTC is not exposed to the risk associated with the difference in the energy component of Locational Marginal Price ("LMP") from day-ahead to real-time like INCs and DECs are.

As discussed in the PJM Post-Technical Conference Comments,[27] the Virtual Transactions Whitepaper,[28] and PJM's Report on Price Formation Issues,[29] PJM continues to believe that UTCs should be allocated uplift in a comparable manner to how uplift is allocated to INCs and DECs. Simply, there is no rational reason why UTCs should continue to be exempt from uplift allocations. PJM's proposed uplift allocation methodology is based on striking a reasonable balance between cost-causation principles and beneficiary principles, as well as remedying the undue discrimination that currently exists. It is effectively impossible to determine uplift causality at the level of an individual transaction (*e.g.*, load withdrawal, generator injection, Virtual Transaction).[30] Therefore, PJM endeavors to allocate uplift charges to either a broad set of causal relationships and to the beneficiaries of the service with which the uplift is associated.

[27] *See* note 13, *supra*.

[28] *See, e.g.,* Virtual Transactions Whitepaper at 35-36, 41, 48.

[29] *See* PJM Price Formation Report at 33.

[30] *See e.g.* PJM Price Formation Report at 28-29.

UTCs are substantially equivalent to an injection of energy at one node and withdrawal at the other node. From a cost-causation perspective, UTCs, like all other Virtual Transactions in the Day-ahead Energy Market, impact the commitment and dispatch of resources in that market, the flows on transmission lines, LMP, and consequently the revenues that resources collect from the market and thus the level of uplift collected. Accordingly, as a category of transactions, they can cause uplift to occur in much the same way as INCs and DECs. From a beneficiary pays perspective, the withdrawal side of the UTC, like all withdrawal transactions in the Day-ahead Energy Market, benefits from the minimization of bid production cost performed by PJM when it clears the Day-ahead Energy Market. This means that the withdrawal side of the UTC is served with the lowest cost available supply. Accordingly, it would be inappropriate to continue to exclude UTCs from being allocated uplift.

PJM is proposing to treat UTCs as an energy-injection deviation and energy-withdrawal deviation between day-ahead and real-time and to charge UTCs a share of the uplift that basis. This market rule change would treat UTCs in the same manner as INCs and DECs are treated under PJM's current uplift allocation methodology. More specifically, the energy withdrawal side of the UTC would receive an allocation of day-ahead uplift (*i.e.* day-ahead Operating Reserves) and an allocation of real-time uplift (*i.e.* balancing Operating Reserves) identical to that of a DEC (which is an energy-withdrawal transaction), and the energy injection side of the UTC would receive an allocation of real-time uplift identical to that of an INC (which is an energy-injection transaction).

Further, by proposing this treatment, PJM is not allowing a Market Participant to net the deviations attributable to the respective energy-withdrawal and energy-injection sides of the

UTC. Allowing netting in that sense would create an inconsistency between the way a UTC would be allocated uplift compared to an identical position taken by INC and a DEC transactions at the same injection and withdrawal points. From a scheduling, dispatch and impact to uplift perspective, it makes no difference whether the position is taken by a UTC or an INC and a DEC. Allowing netting between the supply-side and demand-side deviations of a UTC would lower the amount of uplift allocated to the UTC, and cause the UTC to have a lower percentage of uplift allocated to it relative to the INC and DEC. Allowing netting would accordingly result in a lower cost-per transaction for UTCs relative to INCs and DECs, and therefore would be inequitable if not unduly discriminatory.

III. TARIFF REVISIONS

In order to align the uplift allocation methodologies for all Virtual Transactions, PJM is proposing several changes to Operating Agreement, Schedule 1, section 3.2.3. First, PJM proposes the following revisions to section 3.2.3(d), which describes the calculation of day-ahead Operating Reserves.

> (d) The cost of Operating Reserves in the Day-ahead Energy Market shall be allocated and charged to each Market Participant in proportion to the sum of its (i) scheduled load (net of Behind The Meter Generation expected to be operating, but not to be less than zero), ~~and~~ accepted Decrement Bids in the Day-ahead Energy Market in megawatt-hours for that Operating Day, <u>and the scheduled megawatt-hours at the specified sink of an accepted Up-to Congestion Transaction;</u> and (ii) scheduled energy sales in the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours for that Operating Day, but not including its bilateral transactions that are Dynamic Transfers to load outside such area pursuant to Section 1.12, except to the extent PJM scheduled resources to provide Black Start service, Reactive Services or transfer interface control.

These proposed revisions ensure that Operating Reserves (i.e. uplift) allocated and charged to Market Participants in the Day-ahead Energy Market will now take into account specified sinks of accepted UTCs. In other words, the revisions provide that the withdrawal portion of UTCs are treated like other similar demand–side transactions (including Decrement Bids) in the Day-ahead Energy Market, and that the uplift costs associated with such demand-side transactions are allocated in a similar manner to all Market Participants in the Day-ahead Energy Market.[31]

Next, PJM is proposing the following revisions to section 3.2.3(h), which describes the calculation of balancing Operating Reserves:

> (h)
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>
> The foregoing notwithstanding, netting deviations shall be allowed in accordance with the following provisions:
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> (i) Generation resources with multiple units located at a single bus shall be able to offset deviations in accordance with the PJM Manuals to determine the net deviation MW at the relevant bus.
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> (ii) Demand deviations will be assessed by comparing all day-ahead demand transactions at a single transmission zone, hub, or interface against the real-time demand transactions at that same transmission zone, hub, or interface; except that the positive values of demand deviations, as set forth in the PJM Manuals, will not be assessed Operating Reserve charges in the event of a Primary Reserve or Synchronized Reserve shortage in real-time or where PJM initiates the request for emergency load reductions in real-time in order to avoid a Primary Reserve or Synchronized Reserve shortage. <u>The scheduled megawatt-hour withdrawal at the specified sink for an accepted Decrement Bid or Up-to Congestion Transaction are included in the determination of demand deviations. Bilateral transactions inside the PJM Region, as defined in section 1.7.10 of this Schedule, will not be included in the determination of demand deviations.</u>
>
> (iii) Supply deviations will be assessed by comparing all day-ahead transactions at a single transmission zone, hub, or interface against the real-time transactions at

[31] Uplift is a function of the bulk power system's total bid production cost in the Day-ahead Energy Market, which is lowered by uplift-causing actions. The sole beneficiary of such actions are load interests, which is why all day-ahead uplift is allocated to demand-side transactions and none is allocated to supply-side transactions.

> that same transmission zone, hub, or interface. The scheduled megawatt-hour injection at the specified source for an accepted Increment Offer or Up-to Congestion Transaction are included in the determination of supply deviations. Bilateral transactions inside the PJM Region, as defined in section 1.7.10 of this Schedule, will not be included in the determination of supply deviations.

PJM's proposed revisions include the source-side of the UTC in the calculation of supply deviations and the demand-side of the UTC in the calculation of demand deviations. This is being done to ensure that UTCs are treated in a consistent manner with INCs (supply deviations) and DECs (demand deviations), given each Virtual Transaction's respective characteristics under today's current rules. Further, PJM is proposing a new but minor modification to the calculation of demand and supply deviations that will apply to all Virtual Transactions. Specifically, PJM is proposing to exclude bilateral transactions, as defined in Operating Agreement, Schedule 1, section 1.7.10, from the calculation of supply and demand deviations. This is due to the fact that these bilateral transactions do not impact day-ahead commitment, and therefore uplift, and accordingly should not be considered in the calculation of deviations. Further, allowing bilateral transactions to impact the calculation of supply and demand deviations would allow Market Participants to artificially decrease the amount of uplift they are allocated by using them in a manner to purposefully accomplish this goal.[32] Accordingly, bilateral transactions should be excluded from the calculation of deviations going forward.

IV. OPERATING RESERVE CREDITS

Next, PJM proposes a minor modification to the methodology used to calculate Operating Reserve credits, which, as discussed, are paid to Market Participants to make them whole for following PJM's dispatch instructions so that they are not economically incentivized to ignore

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[32] *See, e.g., DC Energy, LLC, et al. v. PJM Interconnection, L.L.C.*, 138 FERC ¶ 61,165 at P65, Order Denying Complaint, *reh'g denied*, 144 FERC ¶ 61,024 (2012).

such dispatch instructions. Specifically, PJM proposes the following revisions to Operating Agreement, Schedule 1, section 3.2.3(e):[33]

> (e)
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>
> Credits received pursuant to this section shall be equal to the positive difference between a resource's total offered price for start-up (shutdown costs for Demand Resources) and no-load fees and energy, determined on the basis of the resource's scheduled output, and the total value of the resource's energy for hours in the Day-ahead Energy Market that correspond to five-minute intervals in which the resource is operated in real-time pursuant to the Office of the Interconnection's direction, plus any credit or change for quantity deviations, at PJM dispatch direction, from the Day-ahead Energy Market during the Operating Day at the real-time LMP(s) applicable to the relevant generation bus in the Real-time Energy Market. The foregoing notwithstanding, credits for segment 2 shall exclude start up (shutdown costs for Demand Resources) costs for generation resources.

These revisions are necessary because Balancing Operating Reserve Credits are equal to the amount of a resource's total real-time offer including start-up (shutdown costs for Demand Resources) and no-load costs in excess of the total value of the resource's energy in the Day-ahead Energy Market, the balancing energy market value, and ancillary service revenues in excess of a resource's offer plus opportunity costs. However, this can result in a Market Participant actually losing money when the its resource runs in real time for a subset of the Day-ahead commitment, but all revenue of the day-ahead commitment is included in the Balancing Operating Reserve calculation. The current method of including all day-ahead revenues can result in resources not being completely made whole for real-time operating costs because day-ahead revenues in hours in which they did not operate in real-time offset their make whole

[33] PJM notes this language is slightly different than what was approved by stakeholders to reflect PJM's five-minute settlement rules which will be implemented prior to the requested effective date herein. Specifically, in the proposed text, PJM changed the language from "that correspond to hours in which…" to "that correspond to five-minute intervals in which…"

payment. This accordingly disincentives the Market Participant from following PJM's dispatch instructions during certain circumstances, which is antithetical to the central purpose of Operating Reserve credits.

In order to rectify this situation, PJM is proposing that the positive difference between a resource's total offered price for start-up (shutdown costs for Demand Resources) and no-load costs and energy, determined on the basis of the resource's scheduled output, is netted against the total value of the resource's energy for hours in the Day-ahead Energy Market that correspond to hours in which the resource is operated in real-time pursuant to the Office of the Interconnection's direction. This will in turn result in a Balancing Operating Reserve credit that will continue to incentivize Market Participants to follow PJM dispatch instructions.

V. STAKEHOLDER PROCESS

On January 26, 2017, the PJM Markets and Reliability Committee endorsed the proposed revisions to the Tariff and Operating Agreement described herein by sector-weighted vote with 3.95 out of 5.0 in favor. At its meeting held on February 23, 2017, the PJM Members Committee endorsed and approved the proposed revisions to the Tariff and Operating Agreement by sector-weighted vote with 4.16 out of 5.0 in favor.

VI. PROPOSED EFFECTIVE DATE AND REQUEST FOR WAIVER

PJM respectfully asks the Commission to issue an order accepting these proposed revisions on or before December 18, 2017, with an effective date of April 1, 2018. PJM seeks an order in this time frame to have adequate time to implement the information technology and other PJM system changes necessary in time for its requested effective date. Because PJM's requested effective date is more than one hundred and twenty days from the date of filing, PJM seeks waiver of 18 C.F.R. section 35.3(a)(1).

VII. CORRESPONDENCE AND COMMUNICATIONS

The following individuals are designated for inclusion on the official service list in this proceeding and for receipt of any communications regarding this filing:

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VII. DOCUMENTS ENCLOSED

PJM encloses with this transmittal letter:

Attachment A – redline version of the revised sections to the electronic Tariff and Operating Agreement; and

Attachment B – clean version of the revised sections to the electronic Tariff and Operating Agreement.

Attachment C – PJM Virtual Transactions Whitepaper

VIII. SERVICE

PJM has served a copy of this filing on all PJM Members and on all state utility regulatory commissions in the PJM Region by posting this filing electronically. In accordance with the Commission's regulations,[34] PJM will post a copy of this filing to the FERC filing section of its internet site, located at the following link: http://www.pjm.com/documents/ferc-manuals/ferc-filings.aspx with a specific link to the newly-filed document, and will send an e-mail on the same date as this filing to all PJM Members and all state utility regulatory commissions in the PJM Region[35] alerting them that this filing has been made by PJM and is available by following such link. If the document is not immediately available by using the referenced link, the document will be available through the referenced link within 24 hours of the filing. Also, a copy of this filing will be available on the FERC's eLibrary website located at the following link: http://www.ferc.gov/docs-filing/elibrary.asp in accordance with the Commission's regulations and Order No. 714.

[34] *See* 18 C.F.R §§ 35.2(e) and 385.2010(f)(3).

[35] PJM already maintains, updates, and regularly uses e-mail lists for all PJM Members and affected state commissions.

Respectfully submitted,

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Attachment A

Revisions to the
PJM Open Access Transmission Tariff
and PJM Operating Agreement

(Marked / Redline Format)

Section(s) of the
PJM Open Access Transmission Tariff

(Marked / Redline Format)

3.2 Market *Settlements*.

If a dollar-per-MW-hour value is applied in a calculation under this section 3.2 where the interval of the value produced in that calculation is less than an hour, then for purposes of that calculation the dollar-per-MW hour value is divided by the number of Real-time Settlement Intervals in the hour.

3.2.1 Spot Market Energy.

(a) The Office of the Interconnection shall calculate System Energy Prices in the form of Day-ahead System Energy Prices and Real-time System Energy Prices for the PJM Region, in accordance with Section 2 of this Schedule.

(b) *Each* Market *Participant* shall be charged for all *of its Market Participant Energy Withdrawals* scheduled in the Day-ahead Energy Market at the Day-ahead System Energy Price *to be served in the PJM Interchange Energy Market*.

(c) *Each* Market *Participant* shall be paid for all *of its Market Participant Energy Injections* scheduled in the Day-ahead Energy Market at the Day-ahead System Energy Price *to be delivered to the PJM Interchange Energy Market*.

(d) For each Day-ahead Settlement Interval during an Operating Day, the Office of the Interconnection shall calculate Spot Market Energy charges for each Market Participant as the difference between the sum of its Market Participant Energy Withdrawals scheduled times the Day-ahead System Energy Price and the sum of its Market Participant Energy Injections scheduled times the Day-ahead System Energy Price.

(e) For each Real-time Settlement Interval during an Operating Day, the Office of the Interconnection shall calculate Spot Market Energy charges for each Market Participant as the difference between the sum of its real-time Market Participant Energy Withdrawals less its scheduled Market Participant Energy Withdrawals times the Real-time System Energy Price and the sum of its real-time Market Participant Energy Injections less scheduled Market Participant Energy Injections times the Real-time System Energy Price. The Revenue Data for Settlements determined for each Real-time Settlement Interval in accordance with section 3.1A of this Schedule shall be used in determining the real-time Market Participant Energy Withdrawals and Market Participant Energy Injections used to calculate Spot Market Energy charges under this subsection (e).

(f) For pool External Resources, the Office of the Interconnection shall model, based on an appropriate flow analysis, the megawatts of real-time energy injections to be delivered from each such resource to the corresponding Interface Pricing Point between adjacent Control Areas and the PJM Region.

3.2.2 Regulation.

(a) Each Market *Participant* that is a Load Serving Entity in a Regulation Zone shall have an hourly Regulation objective equal to its pro rata share of the Regulation requirements of such Regulation Zone for the hour, based on the Market *Participant's* total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Regulation Zone for the hour ("Regulation Obligation"). A Market *Participant with an* hourly Regulation *O*bligation shall be charged *the pro rata share of the sum of the quantity of regulation provided in each Real-time Settlement Interval times the clearing price for all Real-time Settlement Intervals in the hour associated with that obligation.*

(b) Each Market *Participant supplying Regulation in a Regulation Zone at the direction of the Office of the Interconnection* shall be credited for each of its resources such that the calculated credit for each increment of Regulation provided by each resource shall be the higher of: (i) the Regulation market-clearing price; or (ii) the sum of the applicable Regulation offers for a resource determined pursuant to Section 3.2.2A.1 of this Schedule, the unit-specific shoulder hour opportunity costs described in subsection (e) of this section, the unit-specific inter-temporal opportunity costs, and the unit-specific opportunity costs discussed in subsection (d) of this section.

(c) The total Regulation market-clearing price in each Regulation Zone shall be determined *for each Real-time Settlement Interval.* The total Regulation market-clearing price shall include: (i) the performance Regulation market-clearing price in a Regulation Zone that shall be calculated in accordance with subsection (g) of this section; (ii) the capability Regulation market-clearing price that shall be calculated in accordance with subsection (h) of this section; and (iii) a Regulation resource's unit-specific opportunity costs during the 5-minute period, determined as described in subsection (d) below, divided by the unit-specific benefits factor described in subsection (j) of this section and divided by the historic accuracy score of the resource from among the resources selected to provide Regulation. A resource's Regulation offer by any Market Seller that fails the three-pivotal supplier test set forth in section 3.2.2A.1 of this Schedule shall not exceed the cost of providing Regulation from such resource, plus twelve dollars, as determined pursuant to the formula in section 1.10.1A(e) of this Schedule.

(d) In determining the Regulation 5-minute clearing price for each Regulation Zone, the estimated unit-specific opportunity costs of a generation resource offering to sell Regulation in each regulating hour, except for hydroelectric resources, shall be equal to the product of (i) the deviation of the set point of the generation resource that is expected to be required in order to provide Regulation from the generation resource's expected output level if it had been dispatched in economic merit order times, (ii) the absolute value of the difference between the expected Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource) in the PJM Interchange Energy Market.

For hydroelectric resources offering to sell Regulation in a regulating hour, the estimated unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the

PJM Manuals will be the full value of the Locational Marginal Price at that generation bus for each megawatt of Regulation capability.

The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and has a day-ahead megawatt commitment greater than zero shall be equal to the product of (i) the deviation of the set point of the hydroelectric resource that is expected to be required in order to provide Regulation from the hydroelectric resource's expected output level if it had been dispatched in economic merit order times (ii) the difference between the expected Locational Marginal Price at the generation bus for the hydroelectric resource and the average of the Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating. Estimated opportunity costs shall be zero for hydroelectric resources for which the average Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period, excluding those *Real-time Settlement Intervals* during which all available units at the hydroelectric resource were operating is higher than the actual Locational Marginal Price at the generator bus for the *Real-time Settlement Interval*.

The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead megawatt commitment greater than zero shall be equal to the product of (i) the deviation of the set point of the hydroelectric resource that is expected to be required in order to provide Regulation from the hydroelectric resource's expected output level if it had been dispatched in economic merit order times (ii) the difference between the average of the Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating and the expected Locational Marginal Price at the generation bus for the hydroelectric resource. Estimated opportunity costs shall be zero for hydroelectric resources for which the actual Locational Marginal Price at the generator bus for the *Real-time Settlement Interval* is higher than the average Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period, excluding those *Real-time Settlement Intervals* during which all available units at the hydroelectric resource were operating.

For the purpose of committing resources and setting Regulation market clearing prices, the Office of the Interconnection shall utilize day-ahead Locational Marginal Prices to calculate opportunity costs for hydroelectric resources. For the purposes of settlements, the Office of the Interconnection shall utilize the real-time Locational Marginal Prices to calculate opportunity costs for hydroelectric resources.

Estimated opportunity costs for Demand Resources to provide Regulation are zero.

(e) In determining the credit under subsection (b) to a Market *Participant* selected to provide Regulation in a Regulation Zone and that actively follows the Office of the Interconnection's Regulation signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for *(1)* each *Real-time Settlement Interval* that the Office of the Interconnection requires a generation resource to provide Regulation, and *(2)* the *last three*

Real-time Settlement Intervals of the preceding shoulder hour and the *first three Real-time Settlement Intervals of the* following shoulder hour *in accordance with the PJM Manuals and below*. The unit-specific opportunity cost incurred during the *Real-time Settlement Interval* in which the Regulation obligation is fulfilled shall be equal to the product of (i) the deviation of the generation resource‘s output necessary to follow the Office of the Interconnection‘s Regulation signals from the generation resource‘s expected output level if it had been dispatched in economic merit order times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the actual megawatt level of the resource when the actual megawatt level is within the tolerance defined in the PJM Manuals for the Regulation set point, or at the Regulation set point for the resource when it is not within the corresponding tolerance) in the PJM Interchange Energy Market. Opportunity costs for Demand Resources to provide Regulation are zero.

The unit-specific opportunity costs associated with uneconomic operation during *each of* the preceding *three Real-time Settlement Intervals of the* shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the initial regulating *Real-time Settlement Interval* in order to provide Regulation and the resource‘s expected output in *each of the* preceding *three Real-time Settlement Intervals of the* shoulder hour times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in *each of* the preceding *three Real-time Settlement Intervals of the* shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in the initial regulating *Real-time Settlement Interval*) in the PJM Interchange Energy Market, all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

The unit-specific opportunity costs associated with uneconomic operation during *each of* the following *three Real-time Settlement Intervals of the* shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the final regulating *Real-time Settlement Interval* in order to provide Regulation and the resource‘s expected output in *each of* the following *three Real-time Settlement Intervals of the* shoulder hour times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in *each of* the following *three Real-time Settlement Intervals of the* shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in final regulating hour) in the PJM Interchange Energy Market all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

(f) Any amounts credited for Regulation in an hour in excess of the Regulation market-clearing price in that hour shall be allocated and charged to each Market *Participant* in a Regulation Zone that does not meet its hourly Regulation obligation in proportion to its purchases of Regulation in such Regulation Zone in megawatt-hours during that hour.

(g) To determine the performance Regulation market-clearing price for each Regulation Zone, the Office of the Interconnection shall adjust the submitted performance offer for each resource in accordance with the historical performance of that resource, the amount of Regulation that resource will be dispatched based on the ratio of control signals calculated by the Office of the Interconnection, and the unit-specific benefits factor described in subsection (j) of this section for which that resource is qualified. The maximum adjusted performance offer of all cleared resources will set the performance Regulation market-clearing price.

The owner of each Regulation resource that actively follows the Office of the Interconnection's Regulation signals and instructions, will be credited for Regulation performance by multiplying the assigned MW(s) by the performance Regulation market-clearing price, by the ratio between the requested mileage for the Regulation dispatch signal assigned to the Regulation resource and the Regulation dispatch signal assigned to traditional resources, and by the Regulation resource's accuracy score calculated in accordance with subsection (k) of this section.

(h) The Office of the Interconnection shall divide each Regulation resource's capability offer by the unit-specific benefits factor described in subsection (j) of this section and divided by the historic accuracy score for the resource for the purposes of committing resources and setting the market clearing prices.

The Office of the Interconnection shall calculate the capability Regulation market-clearing price for each Regulation Zone by subtracting the performance Regulation market-clearing price described in subsection (g) from the total Regulation market clearing price described in subsection (c). This residual sets the capability Regulation market clearing price for that market *Real-time Settlement Interval*.

The owner of each Regulation resource that actively follows the Office of the Interconnection's Regulation signals and instructions will be credited for Regulation capability based on the assigned MW and the capability Regulation market-clearing price multiplied by the Regulation resource's accuracy score calculated in accordance with subsection (k) of this section.

(i) In accordance with the processes described in the PJM Manuals, the Office of the Interconnection shall: (i) calculate inter-temporal opportunity costs for each applicable resource; (ii) include such inter-temporal opportunity costs in each applicable resource's offer to sell frequency Regulation service; and (iii) account for such inter-temporal opportunity costs in the Regulation market-clearing price.

(j) The Office of the Interconnection shall calculate a unit-specific benefits factor for each of the dynamic Regulation signal and traditional Regulation signal in accordance with the PJM Manuals. Each resource shall be assigned a unit-specific benefits factor based on their order in the merit order stack for the applicable Regulation signal. The unit-specific benefits factor is the point on the benefits factor curve that aligns with the last megawatt, adjusted by historical performance, that resource will add to the dynamic resource stack. The unit-specific benefits factor for the traditional Regulation signal shall be equal to one.

(k) The Office of the Interconnection shall calculate each Regulation resource's accuracy score. The accuracy score shall be the average of a delay score, correlation score, and energy score for each ten second interval. For purposes of setting the interval to be used for the correlation score and delay scores, PJM will use the maximum of the correlation score plus the delay score for each interval.

The Office of the Interconnection shall calculate the correlation score using the following statistical correlation function (r) that measures the delay in response between the Regulation signal and the resource change in output:

$$\text{Correlation Score} = r_{\text{Signal,Response}(\delta,\delta+5\text{ Min});\ \delta=0\text{ to }5\text{ Min}}$$

where δ is delay.

The Office of the Interconnection shall calculate the delay score using the following equation:

$$\text{Delay Score} = \text{Abs}\left((\delta - 5\text{ Minutes}) / (5\text{ Minutes})\right).$$

The Office of the Interconnection shall calculate a*n* energy score as a function of the difference in the energy provided versus the energy requested by the Regulation signal while scaling for the number of samples. The energy score is the absolute error (ε) as a function of the resource's Regulation capacity using the following equations:

$$\text{Energy Score} = 1 - 1/n \sum \text{Abs (Error)};$$

Error = Average of Abs ((Response - Regulation Signal) / (Hourly Average Regulation Signal)); and

n = the number of samples in the hour and the energy.

The Office of the Interconnection shall calculate an accuracy score for each Regulation resource that is the average of the delay score, correlation score, and energy score for a five-minute period using the following equation where the energy score, the delay score, and the correlation score are each weighted equally:

Accuracy Score = max ((Delay Score) + (Correlation Score)) + (Energy Score).

The historic accuracy score will be based on a rolling average of the *Real-time Settlement Interval* accuracy scores, with consideration of the qualification score, as defined in the PJM Manuals.

3.2.2A Offer Price Caps.

3.2.2A.1 Applicability.

(a) Each hour, the Office of the Interconnection shall conduct a three-pivotal supplier test as described in this section. Regulation offers from Market Sellers that fail the three-pivotal supplier test shall be capped in the hour in which they failed the test at their cost based offers as determined pursuant to section 1.10.1A(e) of this Schedule. A Regulation supplier fails the three-pivotal supplier test in any hour in which such Regulation supplier and the two largest other Regulation suppliers are jointly pivotal.

(b) For the purposes of conducting the three-pivotal supplier test pursuant to this section, the following applies:

(i) The three-pivotal supplier test will include in the definition of available supply all offers from resources capable of satisfying the Regulation requirement of the PJM Region multiplied by the historic accuracy score of the resource and multiplied by the unit-specific benefits factor for which the capability cost-based offer plus the performance cost-based offer plus any eligible opportunity costs is no greater than 150 percent of the clearing price that would be calculated if all offers were limited to cost (plus eligible opportunity costs).

(ii) The three-pivotal supplier test will apply on a Regulation supplier basis (i.e. not a resource by resource basis) and only the Regulation suppliers that fail the three-pivotal supplier test will have their Regulation offers capped. A Regulation supplier for the purposes of this section includes corporate affiliates. Regulation from resources controlled by a Regulation supplier or its affiliates, whether by contract with unaffiliated third parties or otherwise, will be included as Regulation of that Regulation supplier. Regulation provided by resources owned by a Regulation supplier but controlled by an unaffiliated third party, whether by contract or otherwise, will be included as Regulation of that third party.

(iii) Each supplier shall be ranked from the largest to the smallest offered megawatt of eligible Regulation supply adjusted by the historic performance of each resource and the unit-specific benefits factor. Suppliers are then tested in order, starting with the three largest suppliers. For 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 Regulation requirement for the hour to determine the residual supply index. Where the residual supply index for three pivotal suppliers 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 third supplier result in a residual supply index greater than 1.0, at which point the remaining suppliers pass the test. Any resource owner that fails the three-pivotal supplier test will be offer-capped.

3.2.3 Operating Reserves.

(a) A Market Seller's pool-scheduled resources capable of providing Operating Reserves shall be credited as specified below based on the applicable offer for the operation of such resource, provided that the resource was available for the entire time specified in the Offer Data for such resource. To the extent that Section 3.2.3A.01 of Schedule 1 of this Agreement does not meet the Day-ahead Scheduling Reserves Requirement, the Office of the Interconnection shall schedule additional Operating Reserves pursuant to Section 1.7.17 and 1.10 of Schedule 1 of this Agreement. In addition the Office of the Interconnection shall schedule Operating Reserves pursuant to those sections to satisfy any unforeseen Operating Reserve requirements that are not reflected in the Day-ahead Scheduling Reserves Requirement.

(b) The following determination shall be made for each pool-scheduled resource that is scheduled in the Day-ahead Energy Market: the total offered price for Start-up Costs and No-load Costs and energy, determined on the basis of the resource's scheduled output, shall be compared to the total value of that resource's energy – as determined by the Day-ahead Energy Market and the Day-ahead Prices applicable to the relevant generation bus in the Day-ahead Energy Market. PJM shall also (i) determine whether any resources were scheduled in the Day-ahead Energy Market to provide Black Start service, Reactive Services or transfer interface control during the Operating Day because they are known or expected to be needed to maintain system reliability in a Zone during the Operating Day in order to minimize the total cost of Operating Reserves associated with the provision of such services and reflect the most accurate possible expectation of real-time operating conditions in the day-ahead model, which resources would not have otherwise been committed in the day-ahead security-constrained dispatch and (ii) report on the day following the Operating Day the megawatt quantities scheduled in the Day-ahead Energy Market for the above-enumerated purposes for the entire RTO.

Except as provided in Section 3.2.3(n), if the total offered price for Start-up Costs (shutdown costs for Demand Resources) and No-load Costs and energy summed over all *Day-ahead Settlement Intervals* exceeds the total value summed over all *Day-ahead Settlement Intervals*, the difference shall be credited to the Market Seller.

The Office of the Interconnection shall apply any balancing Operating Reserve credits allocated pursuant to this Section 3.2.3(b) to real-time deviations or real-time load share plus exports, pursuant to Section 3.2.3(p), depending on whether the balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

(i) For resources scheduled by the Office of the Interconnection during the reliability analysis for an Operating Day, the associated balancing Operating Reserve credits shall be allocated based on the reason the resource was scheduled according to the following provisions:

(A) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to operate in real-time to augment the physical resources committed in the Day-ahead Energy Market to meet the forecasted real-time load plus the Operating Reserve requirement, the associated balancing Operating Reserve credits, identified as RA Credits for Deviations, shall be allocated to real-time deviations.

(B) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to maintain system reliability, the associated balancing Operating Reserve credits, identified as RA Credits for Reliability, shall be allocated according to ratio share of real time load plus export transactions.

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing Operating Reserves, the associated balancing Operating Reserve credits shall be segmented and separately allocated pursuant to subsections 3.2.3(b)(i)(A) or 3.2.3(b)(i)(B) hereof. Balancing Operating Reserve credits for such resources will be identified in the same manner as units committed during the reliability analysis pursuant to subsections 3.2.3(b)(i)(A) and 3.2.3(b)(i)(B) hereof.

(ii) For resources scheduled during an Operating Day, the associated balancing Operating Reserve credits shall be allocated according to the following provisions:

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Operating Reserve credits, identified as RT Credits for Reliability, shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, credits will be applied pursuant to this section only if the LMP at the resource's bus does not meet or exceed the applicable offer of the resource for at least four 5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the credits for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category (RT Credits for Reliability or RT Credits for Deviations) as identified for the Operating Reserves for the other discrete clock hours.

(B) If the Office of the Interconnection directs a resource not covered by Section 3.2.3(b)(ii)(A) hereof to operate in real-time during an Operating Day, the associated balancing Operating Reserve credits, identified as RT Credits for Deviations, shall be allocated according to real-time deviations from day-ahead schedules.

(iii) PJM shall post on its Web site the aggregate amount of MWs committed that meet the criteria referenced in subsections (b)(i) and (b)(ii) hereof.

(c) The sum of the foregoing credits calculated in accordance with Section 3.2.3(b) plus any unallocated charges from Section 3.2.3(h) and 5.1.7, and any shortfalls paid pursuant to the Market Settlement provision of the Day-ahead Economic Load Response Program, shall be the cost of Operating Reserves in the Day-ahead Energy Market.

(d) The cost of Operating Reserves in the Day-ahead Energy Market shall be allocated and charged to each Market Participant in proportion to the sum of its (i) scheduled load (net of Behind The Meter Generation expected to be operating, but not to be less than zero), ~~and~~ accepted Decrement Bids in the Day-ahead Energy Market in megawatt-hours for that Operating Day, and the scheduled megawatt-hours at the specified sink of an accepted Up-to Congestion Transaction; and (ii) scheduled energy sales in the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours for that Operating Day, but not including its bilateral transactions that are Dynamic Transfers to load outside such area pursuant to Section 1.12, except to the extent PJM scheduled resources to provide Black Start service, Reactive Services or transfer interface control. The cost of Operating Reserves in the Day-ahead Energy Market for resources scheduled to provide Black Start service for the Operating Day which resources would not have otherwise been committed in the day-ahead security constrained dispatch shall be allocated by ratio share of the monthly transmission use of each Network Customer or Transmission Customer serving Zone Load or Non-Zone Load, as determined in accordance with the formulas contained in Schedule 6A of the PJM Tariff. The cost of Operating Reserves in the Day-ahead Energy Market for resources scheduled to provide Reactive Services or transfer interface control because they are known or expected to be needed to maintain system reliability in a Zone during the Operating Day and would not have otherwise been committed in the day-ahead security constrained dispatch shall be allocated and charged to each Market Participant in proportion to the sum of its real-time deliveries of energy to load (net of operating Behind The Meter Generation) in such Zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such Zone.

(e) At the end of each Operating Day, the following determination shall be made for each synchronized pool-scheduled resource of each Market Seller that operates as requested by the Office of the Interconnection. For each calendar day, pool-scheduled resources in the Real-time Energy Market shall be made whole for each of the following Segments: 1) the greater of their day-ahead schedules *and* minimum run time *specified at the time of commitment* (minimum down time *specified at the time of commitment* for Demand Resources); and 2) any block of *Real-time Settlement Intervals* the resource operates at PJM's direction in excess of the greater of its day-ahead schedule *and* minimum run time *specified at the time of commitment* (minimum down time *specified at the time of commitment* for Demand Resources). For each calendar day, and for each synchronized start of a generation resource or PJM-dispatched economic load reduction, there will be a maximum of two Segments for each resource. Segment 1 will be the greater of the day-ahead schedule and minimum run time *specified at the time of commitment* (minimum down time *specified at the time of commitment* for Demand Resources) and Segment 2 will include the remainder of the contiguous *Real-time Settlement Intervals* when the resource is operating at the direction of the Office of the Interconnection, provided that a segment is limited to the Operating Day in which it commenced and cannot include any part of the following Operating Day.

A Generation Capacity Resource that operates outside of its unit-specific parameters will not receive Operating Reserve Credits nor be made whole for such operation when not dispatched by the Office of the Interconnection, unless the Market Seller of the Generation Capacity Resource can justify to the Office of the Interconnection that operation outside of such unit-specific parameters was the result of an actual constraint. Such Market Seller shall provide to the Market Monitoring Unit and the Office of the Interconnection its request to receive Operating Reserve Credits and/or to be made whole for such operation, along with documentation explaining in detail the reasons for operating its resource outside of its unit-specific parameters, within thirty calendar days following the issuance of billing statement for the Operating Day. The Market Seller shall also respond to additional requests for information from the Market Monitoring Unit and the Office of the Interconnection. The Market Monitoring Unit shall evaluate such request for compensation and provide its determination of whether there was an exercise of market power to the Office of the Interconnection by no later than twenty-five calendar days after receiving the Market Seller's request for compensation. The Office of the Interconnection shall make its determination whether the Market Seller justified that it is entitled to receive Operating Reserve Credits and/or be made whole for such operation of its resource for the day(s) in question, by no later than thirty calendar days after receiving the Market Seller's request for compensation.

Credits received pursuant to this section shall be equal to the positive difference between a resource's Total Operating Reserve Offer, and the total value of the resource's energy for hours in the Day-ahead Energy Market that correspond to five-minute intervals in which the resource is operated in real-time pursuant to the Office of the Interconnection's direction, plus any credit or change for quantity deviations, at PJM dispatch direction (excluding quantity deviations caused by an increase in the Market Seller's Real-time Offer), from the Day-ahead Energy Market during the Operating Day at the real-time LMP(s) applicable to the relevant generation bus in the Real-time Energy Market. The foregoing notwithstanding, credits for segment 2 shall exclude start up (shutdown costs for Demand Resources) costs for generation resources.

Except as provided in Section 3.2.3(m), if the total offered price exceeds the total value, the difference less any credit as determined pursuant to Section 3.2.3(b), and less any amounts credited for Synchronized Reserve in excess of the Synchronized Reserve offer plus the resource's opportunity cost, and less any amounts credited for Non-Synchronized Reserve in excess of the Non-Synchronized Reserve offer plus the resource's opportunity cost, and less any amounts credited for providing Reactive Services as specified in Section 3.2.3B, and less any amounts for Day-ahead Scheduling Reserve in excess of the Day-ahead Scheduling Reserve offer plus the resource's opportunity cost, shall be credited to the Market Seller.

Synchronized Reserve, Non-Synchronized Reserve, and *Real-time Settlement Interval share of the* Day-ahead Scheduling Reserve credits applied against Operating Reserve credits pursuant to this section shall be netted against the Operating Reserve credits earned in the corresponding *Real-time Settlement Interval*(s) in which the Synchronized Reserve, Non-Synchronized Reserve, and Day-ahead Scheduling Reserve credits accrued, provided that for condensing combustion turbines, Synchronized Reserve credits will be netted against the total Operating Reserve credits accrued during each *Real-time Settlement Interval* the unit operates in condensing and generation mode.

(f) A Market Seller of a unit not defined in subsection (f-1), (f-2), or (f-4) hereof (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited *for each Real-time Settlement Interval* in an amount equal to the product of (A) the deviation of the generating unit's output necessary to follow the Office of the Interconnection's signals and the generating unit's expected output level if it had been dispatched in economic merit order, times (B) the Locational Marginal Price at the generation bus for the generating unit, minus (C) the Total Lost Opportunity Cost Offer, provided that the resulting outcome is greater than $0.00. This equation is represented as (A*B) - C.

(f-1) With the exception of Market Sellers of Flexible Resources that submit a Real-time Offer greater than their resource's Committed Offer in the Day-ahead Energy Market, a Market Seller of a Flexible Resource, shall be compensated for lost opportunity cost, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Generation Resource Maximum Output, if either of the following conditions occur:

(i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as directed by the PJM dispatcher), then the Market Seller shall be credited in a manner consistent with that described in section 3.2.3 (f).

(ii) *If the unit* is scheduled to produce energy in the Day-ahead Energy Market *for a Day-ahead Settlement Interval*, but the unit is not called on by the Office of the Interconnection and does not operate in *the corresponding Real-time Settlement Interval(s)*, then the Market Seller shall be credited in an amount equal to the higher of:

1) the product of (A) the amount of megawatts committed in the Day-ahead Energy Market for the generating unit, and (B) the Real-time Price at the generation bus for the generating unit, minus the sum of (C) the Total Lost Opportunity Cost Offer plus No-load Costs, plus (D) the Start-up Cost, divided by the *Real-time Settlement Intervals* committed for each set of contiguous hours for which the unit was scheduled in Day-ahead Energy Market. This equation is represented as (A*B) - (C+D). The startup cost, (D), shall be excluded from this calculation if the unit operates in real time following the Office of the Interconnection's direction during any portion of the set

of contiguous hours for which the unit was scheduled in Day-ahead Energy Market, or

2) the Real-time Price at the unit's bus minus the Day-ahead Price at the unit's bus, multiplied by the number of megawatts committed in the Day-ahead Energy Market for the generating unit.

Market Sellers of Flexible Resources that submit a Real-time Offer greater than their resource's Committed Offer in the Day-ahead Energy Market shall not be eligible to receive compensation for lost opportunity costs under any applicable provisions of Schedule 1 of this Agreement.

(f-2) A Market Seller of a hydroelectric resource that is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), the output of which is altered at the request of the Office of the Interconnection from the schedule submitted by the owner, due to a transmission constraint or other reliability issue, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(f-3) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for opportunity cost associated with following PJM dispatch instructions and reducing or suspending a unit's output due to a transmission constraint or other reliability issue, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of opportunity cost compensation, the Office of the Interconnection shall invoice the Market Seller accordingly. If the Market Monitoring Unit disagrees with the modified amount of opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(f-4) A Market Seller *of a* wind generating unit that is pool-scheduled or self-scheduled, has SCADA capability to transmit and receive instructions from the Office of the Interconnection, has provided data and established processes to follow PJM basepoints pursuant to the requirements for wind generating units as further detailed in this Agreement, the Tariff and the PJM Manuals, and which is operating as requested by the Office of the Interconnection, the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited *for each Real-time Settlement Interval* in an amount equal to the product of (A) the deviation of the generating unit's output necessary to follow the Office of the Interconnection's signals and the generating unit's expected output level if it had been dispatched in economic merit order, times (B) the Real-time Price at the generation bus for the generating unit, minus (C) the Total Lost Opportunity Cost Offer, provided that the resulting outcome is greater than $0.00. This equation is represented as (A*B) - C.

(g) The sum of the foregoing credits, plus any cancellation fees paid in accordance with Section 1.10.2(d), such cancellation fees to be applied to the Operating Day for which the unit was scheduled, plus any shortfalls paid pursuant to the Market Settlement provision of the real-time Economic Load Response Program, less any payments received from another Control Area for Operating Reserves shall be the cost of Operating Reserves for the Real-time Energy Market in each Operating Day.

(h) The cost of Operating Reserves for the Real-time Energy Market for each Operating Day, except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, shall be allocated and charged to each Market Participant *based on their daily total of hourly deviations determined in accordance with the following equation:*

$$\sum_h (A + B + C)$$

Where:

h = the hours in the applicable Operating Day;

A = For each Real-Time Settlement Interval in an hour, the sum of the absolute value of the withdrawal deviations (in MW) between the quantities scheduled in the Day-ahead Energy Market and the Market Participant's energy withdrawals (net of operating Behind The Meter Generation) in the Real-Time Energy Market, except as noted in subsection (h)(ii) below and in the PJM Manuals *divided by the number of Real-time Settlement Intervals for that hour. The summation of each Real-time Settlement Interval's withdrawal deviation in an hour will be the Market Participant's total hourly withdrawal deviations. Market Participant bilateral transactions that are Dynamic Transfers to load outside the PJM Region pursuant to section 1.12 of this Schedule are not included in the determination of withdrawal deviation*s;

B = For each Real-Time Settlement Interval in an hour, the sum of the absolute value of generation deviations (*in MW and* not including deviations in Behind The Meter Generation) *as determined in subsection (o) divided by the number of Real-Time Settlement Intervals for that hour*;

C = For each Real-Time Settlement Interval in an hour, the sum of the absolute value of the injection deviations (in MW) between the quantities scheduled in the Day-ahead Energy Market and the Market Participant's energy injections in the Real-Time Energy Market divided by the number of Real-time Settlement Intervals for that hour. The summation of the injection deviations for each Real-time Settlement Interval in an hour will be the Market Participant's total hourly injection deviations. The determination of injection deviations does not include generation resources.

The Revenue Data for Settlements determined for each Real-time Settlement Interval in accordance with section 3.1A of this Schedule shall be used in determining the real-time withdrawal deviations, generation deviations and injection deviations used to calculate Operating Reserve under this subsection (e).

The costs associated with scheduling of units for Black Start service or testing of Black Start Units shall be allocated by ratio share of the monthly transmission use of each Network Customer or Transmission Customer serving Zone Load or Non-Zone Load, as determined in accordance with the formulas contained in Schedule 6A of the PJM Tariff.

Notwithstanding section (h)(1) above, as more fully set forth in the PJM Manuals, load deviations from the Day-ahead Energy Market shall not be assessed Operating Reserves charges to the extent attributable to reductions in the load of Price Responsive Demand that is in response to an increase in Locational Marginal Price from the Day-ahead Energy Market to the Real-time Energy Market and that is in accordance with a properly submitted PRD Curve.

Deviations that occur within a single Zone shall be associated with the Eastern or Western Region, as defined in Section 3.2.3(q) of this Schedule, and shall be subject to the regional balancing Operating Reserve rate determined in accordance with Section 3.2.3(q). Deviations at a hub shall be associated with the Eastern or Western Region if all the buses that define the hub are located in the region. Deviations at an Interface Pricing Point shall be associated with whichever region, the Eastern or Western Region, with which the majority of the buses that define that Interface Pricing Point are most closely electrically associated. If deviations at interfaces and hubs are associated with the Eastern or Western region, they shall be subject to the regional balancing Operating Reserve rate. Demand and supply deviations shall be based on total activity in a Zone, including all aggregates and hubs defined by buses that are wholly contained within the same Zone.

The foregoing notwithstanding, netting deviations shall be allowed *for each Real-time Settlement Interval* in accordance with the following provisions:

(i) Generation resources with multiple units located at a single bus shall be able to offset deviations in accordance with the PJM Manuals to determine the net deviation MW at the relevant bus.

(ii) Demand deviations will be assessed by comparing all day-ahead demand transactions at a single transmission zone, hub, or interface against the real-time demand transactions at that same transmission zone, hub, or interface; except that the positive values of demand deviations, as set forth in the PJM Manuals, will not be assessed Operating Reserve charges in the event of a Primary Reserve or Synchronized Reserve shortage in real-time or where PJM initiates the request for emergency load reductions in real-time in order to avoid a Primary Reserve or Synchronized Reserve shortage. The scheduled megawatt-hour withdrawal at the specified sink for an accepted Decrement Bid or Up-to Congestion Transaction are included in the determination of demand deviations. Bilateral transactions inside the PJM Region, as defined in section 1.7.10 of this Schedule, will not be included in the determination of demand deviations.

(iii) Supply deviations will be assessed by comparing all day-ahead transactions at a single transmission zone, hub, or interface against the real-time transactions at that same transmission zone, hub, or interface. The scheduled megawatt-hour injection at the specified source for an accepted Increment Offer or Up-to Congestion Transaction are included in the determination of supply deviations. Bilateral transactions inside the PJM Region, as defined in section 1.7.10 of this Schedule, will not be included in the determination of supply deviations.

(i) At the end of each Operating Day, Market Sellers shall be credited on the basis of their offered prices for synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, as well as the credits calculated as specified in Section 3.2.3(b) for those generators committed solely for the purpose of providing synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, at the request of the Office of the Interconnection.

(j) The sum of the foregoing credits as specified in Section 3.2.3(i) shall be the cost of Operating Reserves for synchronous condensing for the PJM Region for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-contingency operation for the Operating Day and shall be separately determined for the PJM Region.

(k) The cost of Operating Reserves for synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-contingency operation for each Operating Day shall be allocated and charged to each Market Participant in proportion to the sum of its (i) deliveries of energy to load (net of operating Behind The Meter Generation, but not to be less than zero) in the PJM Region, served under Network Transmission Service, in megawatt-hours during that Operating Day; and (ii) deliveries of energy sales from within the PJM Region to load outside such region in megawatt-hours during that Operating Day, but not including its bilateral transactions that are Dynamic Transfers to load outside the PJM Region pursuant to Section 1.12, as compared to the sum of all such deliveries for all Market Participants.

(l) For any Operating Day in either, as applicable, the Day-ahead Energy Market or the Real-time Energy Market for which, for all or any part of such Operating Day, the Office of the Interconnection: (i) declares a Maximum Generation Emergency; (ii) issues an alert that a Maximum Generation Emergency may be declared ("Maximum Generation Emergency Alert"); or (iii) schedules units based on the anticipation of a Maximum Generation Emergency or a Maximum Generation Emergency Alert, the Operating Reserves credit otherwise provided by Section 3.2.3.(b) or Section 3.2.3(e) in connection with market-based offers shall be limited as provided in subsections (n) or (m), respectively. The Office of the Interconnection shall provide timely notice on its internet site of the commencement and termination of any of the actions described in subsection (i), (ii), or (iii) of this subsection (l) (collectively referred to as "MaxGen Conditions"). Following the posting of notice of the commencement of a MaxGen Condition, a Market Seller may elect to submit a cost-based offer in accordance with Schedule 2 of the Operating Agreement, in which case subsections (m) and (n) shall not apply to such offer; provided, however, that such offer must be submitted in accordance with the deadlines in Section 1.10 for the submission of offers in the Day-ahead Energy Market or Real-time Energy Market, as applicable. Submission of a cost-based offer under such conditions shall not be precluded by Section 1.9.7(b); provided, however, that the Market Seller must return to compliance with Section 1.9.7(b) when it submits its bid for the first Operating Day after termination of the MaxGen Condition.

(m) For the Real-time Energy Market, if the Effective Offer Price (as defined below) for a market-based offer is greater than $1,000/MWh and greater than the Market Seller's lowest available and applicable cost-based offer, the Market Seller shall not receive any credit for Operating Reserves. For purposes of this subsection (m), the Effective Offer Price shall be the amount that, absent subsections (l) and (m), would have been credited for Operating Reserves for such Operating Day pursuant to Section 3.2.3(e) plus the Real-time Energy Market revenues for the *Real-time Settlement Intervals* that the offer is economic divided by the megawatt hours of energy provided during the *Real-time Settlement Intervals* that the offer is economic. The *Real-time Settlement Intervals* that the offer is economic shall be: (i) the *Real-time Settlement Intervals* that the offer price for energy is less than or equal to the Real-time Price for the relevant generation bus, (ii) the *Real-time Settlement Intervals* in which the offer for energy is greater than Locational Marginal Price and the unit is operated at the direction of the Office of the Interconnection that are in addition to any *Real-time Settlement Intervals* required due to the minimum run time or other operating constraint of the unit, and (iii) for any unit with a minimum run time of one hour or less and with more than one start available per day, any hours the unit operated at the direction of the Office of the Interconnection.

(n) For the Day-ahead Energy Market, if notice of a MaxGen Condition is provided prior to 10:30 a.m. on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price for a market-based offer is greater than $1,000/MWh and greater than the Market Seller's lowest available and applicable cost-based offer, the Market Seller shall not receive any credit for Operating Reserves. If notice of a MaxGen Condition is provided after 10:30 a.m. on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than $1,000/MWh, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. If the Effective Offer Price is less than or equal to $1,000/MWh, regardless of when notice of a MaxGen Condition is provided, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. For purposes of this subsection (n), the Effective Offer Price shall be the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day divided by the megawatt hours of energy offered during the Specified Hours, plus the offer for energy during such hours. The Specified Hours shall be the lesser of: (1) the minimum run hours stated by the Market Seller in its Offer Data; and (2) either (i) for steam-electric generating units and for combined-cycle units when such units are operating in combined-cycle mode, the six consecutive hours of highest Day-ahead Price during such Operating Day when such units are running or (ii) for combustion turbine units and for combined-cycle units when such units are operating in combustion turbine mode, the two consecutive hours of highest Day-ahead Price during such Operating Day when such units are running. Notwithstanding any other provision in this subsection, the total compensation to a Market Seller on any Operating Day that includes a MaxGen Condition shall not exceed $1,000/MWh during the Specified Hours, where such total compensation in each such hour is defined as the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day pursuant to Section 3.2.3(b) divided by the Specified Hours, plus the Day-ahead Price for such hour, and no Operating Reserves payments shall be made for any other hour of such Operating Day. If a unit operates in real time at the direction of the Office of the Interconnection consistently with its day-ahead clearing, then subsection (m) does not apply.

(o) Dispatchable pool-scheduled generation resources and dispatchable self-scheduled generation resources that follow dispatch shall not be assessed balancing Operating Reserve deviations. Pool-scheduled generation resources and dispatchable self-scheduled generation resources that do not follow dispatch shall be assessed balancing Operating Reserve deviations in accordance with the calculations described below and in the PJM Manuals.

The Office of the Interconnection shall calculate a ramp-limited desired MW value for generation resources where the economic minimum and economic maximum are at least as far apart in real-time as they are in day-ahead according to the following parameters:

(i) real-time economic minimum <= 105% of day-ahead economic minimum or day-ahead economic minimum plus 5 MW, whichever is greater.

(ii) real-time economic maximum >= 95% day-ahead economic maximum or day-ahead economic maximum minus 5 MW, whichever is lower.

The ramp-limited desired MW value for a generation resource shall be equal to:

$$\mathbf{Ramp\_Request}_{t} = \left(\mathbf{UDStarget}_{t-1} - \mathbf{AOutput}_{t-1}\right) \Big/ \left(\mathbf{UDSLAtime}_{t-1}\right)$$

$$\mathbf{RL\_Desired}_{t} = \mathbf{AOutput}_{t-1} + \left(\mathbf{Ramp\_Request}_{t} * \mathbf{Case\_Eff\_time}_{t-1}\right)$$

where:

1. UDStarget = UDS basepoint for the previous UDS case
2. AOutput = Unit’s output at case solution time
3. UDSLAtime = UDS look ahead time
4. Case_Eff_time = Time between base point changes
5. RL_Desired = Ramp-limited desired MW

To determine if a generation resource is following dispatch the Office of the Interconnection shall determine the unit’s MW off dispatch and % off dispatch by using the lesser of the difference between the actual output and the UDS Basepoint or the actual output and ramp-limited desired MW value *for each Real-time Settlement Interval*. If the UDS Basepoint and the ramp-limited desired MW for the resource are unavailable, the Office of the Interconnection will determine the unit’s MW off dispatch and % off dispatch by calculating the lesser of the difference between the actual output and the UDS LMP Desired MW *for each Real-time Settlement Interval*.

A pool-scheduled or dispatchable self-scheduled resource is considered to be following dispatch if its actual output is between its ramp-limited desired MW value and UDS Basepoint, or if its % off dispatch is <= 10, or its Real-time *Settlement Interval* MWh is within 5% of the *Real-time Settlement Interval* ramp-limited desired MW. A self-scheduled generator must also be dispatched above economic minimum. The degree of deviations for resources that are not following dispatch shall be determined *for each Real-time Settlement Interval* in accordance with the following provisions:

- A dispatchable self-scheduled resource that is not dispatched above economic minimum shall be assessed balancing Operating Reserve deviations according to the following formula: Real-time *Settlement Interval* MWh – Day-Ahead MWh.

- A resource that is dispatchable day-ahead but is Fixed Gen in real-time shall be assessed balancing Operating Reserve deviations according to the following formula: Real-time *Settlement Interval* MWh – UDS LMP Desired MW.

- Pool-scheduled generators that are not following dispatch shall be assessed balancing Operating Reserve deviations according to the following formula: Real-time *Settlement Interval* MWh – Ramp-Limited Desired MW.

- If a resource's real-time economic minimum is greater than its day-ahead economic minimum by 5% or 5 MW, whichever is greater, or its real-time economic maximum is less than its Day Ahead economic maximum by 5% or 5 MW, whichever is lower, and UDS LMP Desired MWh for the *Real-time Settlement Interval* is either below the real time economic minimum or above the real time economic maximum, then balancing Operating Reserve deviations for the resource shall be assessed according to the following formula: Real time *Settlement Interval* MWh – UDS LMP Desired MWh.

- If a resource is not following dispatch and its % Off Dispatch is <= 20%, balancing Operating Reserve deviations shall be assessed according to the following formula: Real-time *Settlement Interval MWh* – Ramp-Limited Desired MW. If deviation value is within 5% of Ramp-Limited Desired MW, balancing Operating Reserve deviations shall not be assessed.

- If a resource is not following dispatch and its % off Dispatch is > 20%, balancing Operating Reserve deviations shall be assessed according to the following formula: Real time *Settlement Interval* MWh – UDS LMP Desired MWh.

- If a resource is not following dispatch, and the resource has tripped, for the *Real-time Settlement Interval* the resource tripped and the *Real-time Settlement Intervals* it remains offline throughout its day-ahead schedule balancing Operating Reserve deviations shall be assessed according to the following formula: Real time *Settlement Interval* MWh – Day-Ahead MWh.

- For resources that are not dispatchable in both the Day-Ahead and Real-time Energy Markets balancing Operating Reserve deviations shall be assessed according to the following formula: Real-time *Settlement Interval* MWh - Day-Ahead MWh.

If a resource has a sum of the absolute value of generator deviations for an hour that is less than 5 MWh, then the resource shall not be assessed balancing Operating Reserve deviations for that hour.

(o-1) Dispatchable economic load reduction resources that follow dispatch shall not be assessed balancing Operating Reserve deviations. Economic load reduction resources that do not follow dispatch shall be assessed balancing Operating Reserve deviations as described in this subsection and as further specified in the PJM Manuals.

The Desired MW quantity for such resources for each hour shall be the hourly integrated MW quantity to which the load reduction resource was dispatched for each hour (where the hourly integrated value is the average of the dispatched values as determined by the Office of the Interconnection for the resource for each hour).

If the actual reduction quantity for the load reduction resource for a given hour deviates by no more than 20% above or below the Desired MW quantity, then no balancing Operating Reserve deviation will accrue for that hour. If the actual reduction quantity for the load reduction resource for a given hour is outside the 20% bandwidth, the balancing Operating Reserve deviations will accrue for that hour in the amount of the absolute value of (Desired MW – actual reduction quantity). For those hours where the actual reduction quantity is within the 20% bandwidth specified above, the load reduction resource will be eligible to be made whole for the total value of its offer as defined in section 3.3A of this Appendix. Hours for which the actual reduction quantity is outside the 20% bandwidth will not be eligible for the make-whole payment. If at least one hour is not eligible for make-whole payment based on the 20% criteria, then the resource will also not be made whole for its shutdown cost.

(p) The Office of the Interconnection shall allocate the charges assessed pursuant to Section 3.2.3(h) of Schedule 1 of this Agreement except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, to real-time deviations from day-ahead schedules or real-time load share plus exports depending on whether the underlying balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

(i) For resources scheduled by the Office of the Interconnection during the reliability analysis for an Operating Day, the associated balancing Operating Reserve charges shall be allocated based on the reason the resource was scheduled according to the following provisions:

(A) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to operate in real-time to augment the physical resources committed in the Day-ahead

Energy Market to meet the forecasted real-time load plus the Operating Reserve requirement, the associated balancing Operating Reserve charges shall be allocated to real-time deviations from day-ahead schedules.

(B) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to maintain system reliability, the associated balancing Operating Reserve charges shall be allocated according to ratio share of real time load plus export transactions.

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing Operating Reserves, the associated balancing Operating Reserve charges shall be allocated pursuant to (A) or (B) above.

(ii) For resources scheduled during an Operating Day, the associated balancing Operating Reserve charges shall be allocated according to the following provisions:

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Operating Reserve charges shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, charges will be assessed pursuant to this section only if the LMP at the resource's bus does not meet or exceed the applicable offer of the resource for at least four-5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the charges for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category as identified for the Operating Reserves for the other discrete clock hours.

(B) If the Office of the Interconnection directs a resource not covered by Section 3.2.3(h)(ii)(A) of Schedule 1 of this Agreement to operate in real-time during an Operating Day, the associated balancing Operating Reserve charges shall be allocated according to real-time deviations from day-ahead schedules.

(q) The Office of the Interconnection shall determine regional balancing Operating Reserve rates for the Western and Eastern Regions of the PJM Region. For the purposes of this section, the Western Region shall be the AEP, APS, ComEd, Duquesne, Dayton, ATSI, DEOK, EKPC transmission Zones, and the Eastern Region shall be the AEC, BGE, Dominion, PENELEC, PEPCO, ME, PPL, JCPL, PECO, DPL, PSEG, RE transmission Zones. The regional balancing Operating Reserve rates shall be determined in accordance with the following provisions:

(i) The Office of the Interconnection shall calculate regional adder rates for the Eastern and Western Regions. Regional adder rates shall be equal to the total balancing Operating Reserve credits paid to generators for transmission constraints that occur on transmission system capacity equal to or less than 345kv. The regional adder rates shall be separated into reliability and deviation charges, which shall be allocated to real-time load or real-time deviations, respectively. Whether the underlying credits are designated as reliability or deviation charges shall be determined in accordance with Section 3.2.3(p).

(ii) The Office of the Interconnection shall calculate RTO balancing Operating Reserve rates. RTO balancing Operating Reserve rates shall be equal to balancing Operating Reserve credits except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, in excess of the regional adder rates calculated pursuant to Section 3.2.3(q)(i) of Schedule 1 of this Agreement. The RTO balancing Operating Reserve rates shall be separated into reliability and deviation charges, which shall be allocated to real-time load or real-time deviations, respectively. Whether the underlying credits are allocated as reliability or deviation charges shall be determined in accordance with Section 3.2.3(p).

(iii) Reliability and deviation regional balancing Operating Reserve rates shall be determined by summing the relevant RTO balancing Operating Reserve rates and regional adder rates.

(iv) If the Eastern and/or Western Regions do not have regional adder rates, the relevant regional balancing Operating Reserve rate shall be the reliability and/or deviation RTO balancing Operating Reserve rate.

(r) Market Sellers that incur incremental operating costs for a generation resource *that are either* greater than $1,000/MWh *as* determined in accordance with the *Market Seller's PJM-approved Fuel Cost Policy,* Schedule 2 of the Operating Agreement and PJM Manual 15, *but are not verified at the time of dispatch of the resource under section 6.4.3 of this Schedule, or greater than $2,000/MWh as determined in accordance with the Market Seller's PJM-approved Fuel Cost Policy, Schedule 2 of the Operating Agreement, and PJM Manual 15,* will be eligible to receive credit for Operating Reserves upon review of the Market Monitoring Unit and the Office of the Interconnection, and approval of the Office of the Interconnection. Market Sellers must submit to the Office of the Interconnection and the Market Monitoring Unit all relevant documentation demonstrating the calculation of costs greater than *$2,000/MWh, and costs greater than* $1,000/MWh *which were not verified at the time of dispatch of the resource under section 6.4.3 of this Schedule.* The Office of the Interconnection must approve any Operating Reserve credits paid to a Market Seller under this subsection (r).

3.2.3A Synchronized Reserve.

(a) Each Market Participant that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Synchronized Reserve equal to its pro rata share of Synchronized Reserve requirements for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market *Participant's* total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone or Reserve Sub-zone for the hour ("Synchronized Reserve Obligation"), less any amount obtained from condensers associated with provision of Reactive Services as described in section 3.2.3B(i) and any amount obtained from condensers associated with post-contingency operations, as described in section 3.2.3C(b). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. A Market Participant *with an* hourly Synchronized Reserve Obligation shall be charged *the pro rata share of the sum of the quantity of Synchronized Reserves provided in each Real-time Settlement Interval times the clearing price for all Real-time Settlement Intervals in the hour associated with that obligation*.

(b) A resource supplying Synchronized Reserve at the direction of the Office of the Interconnection, in excess of its hourly Synchronized Reserve Obligation, shall be credited as follows:

i) Credits for Synchronized Reserve provided by generation resources that are then subject to the energy dispatch signals and instructions of the Office of the Interconnection and that increase their current output or Demand Resources that reduce their load in response to a Synchronized Reserve Event ("Tier 1 Synchronized Reserve") shall be at the Synchronized Energy Premium Price*, as described in 3.2.3A (c)*, with the exception of those *Real-time Settlement Intervals* in which the Non-Synchronized Reserve Market Clearing Price for the applicable Reserve Zone or Reserve Sub-zone is not equal to zero. During such hours, Tier 1 Synchronized Reserve resources shall be compensated at the Synchronized Reserve Market Clearing Price for the applicable Reserve Zone or Reserve Sub-zone for the lesser of the amount of Tier 1 Synchronized Reserve attributed to the resource as calculated by the Office of the Interconnection, or the actual amount of Tier 1 Synchronized Reserve provided should a Synchronized Reserve Event occur *in a Real-time Settlement Interval*.

ii) Credits for Synchronized Reserve provided by generation resources that are synchronized to the grid but, at the direction of the Office of the Interconnection, are operating at a point that deviates from the Office of the Interconnection energy dispatch signals and instructions ("Tier 2 Synchronized Reserve") shall be the higher of (i) the Synchronized Reserve Market Clearing Price or (ii) the sum of (A) the Synchronized Reserve offer, and (B) the specific opportunity cost of the generation resource supplying the increment of Synchronized Reserve, as determined by the Office of the Interconnection *to a Synchronized Reserve Event in a Real-time Settlement Interval* in accordance with procedures specified in the PJM Manuals.

iii) Credits for Synchronized Reserve provided by Demand Resources that are synchronized to the grid and accept the obligation to reduce load in response to a Synchronized Reserve Event *in a Real-time Settlement Interval* initiated by the Office of the Interconnection shall be the sum of (i) the higher of (A) the Synchronized Reserve offer or (B) the Synchronized Reserve Market Clearing Price and (ii) if a Synchronized

Reserve Event is actually initiated by the Office of the Interconnection and the Demand Resource reduced its load in response to the event, the fixed costs associated with achieving the load reduction, as specified in the PJM Manuals.

(c) The Synchronized Reserve Energy Premium Price is an adder in an amount to be determined periodically by the Office of the Interconnection not less than fifty dollars and not to exceed one hundred dollars per megawatt hour.

(d) The Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each *Real-time Settlement Interval* of the Operating Day. The hourly Synchronized Reserve Market Clearing Price shall be calculated as the 5-minute clearing price. Each 5-minute clearing price shall be calculated as the marginal cost of serving the next increment of demand for Synchronized Reserve in each Reserve Zone or Reserve Sub-zone, inclusive of Synchronized Reserve offer prices and opportunity costs. When the Synchronized Reserve Requirement or Extended Synchronized Reserve Requirement in a Reserve Zone or Reserve Sub-zone cannot be met, the 5-minute clearing price shall be at least greater than or equal to the applicable Reserve Penalty Factor for the Reserve Zone or Reserve Sub-zone, but less than or equal to the sum of the Reserve Penalty Factors for the Synchronized Reserve Requirement and Primary Reserve Requirement for the Reserve Zone or Reserve Sub-zone. If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a Voltage Reduction Action as described in the PJM Manuals or a Manual Load Dump Action as described in the PJM Manuals, the 5-minute clearing price shall be the sum of the Reserve Penalty Factors for the Primary Reserve Requirement and the Synchronized Reserve Requirement for that Reserve Zone or Reserve Sub-zone.

The Reserve Penalty Factor for the Synchronized Reserve Requirement shall be $850/MWh.

The Reserve Penalty Factor for the Extended Synchronized Reserve Requirement shall be $300/MWh.

By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to prices exceeding $1,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Synchronized Reserve Penalty Factors are warranted for subsequent Delivery Year(s).

(e) *For each Real-time Settlement Interval and for* determining the 5-minute Synchronized Reserve clearing price, the estimated unit-specific opportunity cost for a generation resource *will be determined in accordance with the following equation:*

(A x B) + (C x D)

Where:

A = *T*he Locational Marginal Price at the generation bus for the generation resource*;*

B = *T*he megawatts of energy used to provide Synchronized Reserve submitted as part of the Synchronized Reserve offer*;*

*C = T*he deviation of the set point of the generation resource that is expected to be required in order to provide Synchronized Reserve from the generation resource's expected output level if it had been dispatched in economic merit order*;and*

*D=T*he difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource.

The opportunity costs for a Demand Resource shall be zero.

(f) In determining the credit under subsection (b) to a resource selected to provide Tier 2 Synchronized Reserve and that actively follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each *Real-time Settlement Interval* that the Office of the Interconnection requires a generation resource to provide Tier 2 Synchronized Reserve and shall be *in accordance with the following equation:*

(A x B) + (C x D)

Where:

A *= T*he megawatts of energy used by the resource to provide Synchronized Reserve as submitted as part of the generation resource's Synchronized Reserve offer*;*

B *= T*he Locational Marginal Price at the generation bus of the generation resource*;*

*C = T*he deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order*; and*

*D = T*he difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the generation resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource.

The opportunity costs for a Demand Resource shall be zero.

(g) Charges for Tier 1 Synchronized Reserve will be allocated in proportion to the amount of Tier 1 Synchronized Reserve applied to each Synchronized Reserve Obligation. In the event Tier 1 Synchronized Reserve is provided by a Market *Participant* in excess of that

Market *Participant's* Synchronized Reserve Obligation, the Tier 1 Synchronized Reserve that is not utilized to fulfill the *Market Participant's* obligation will be allocated proportionately among all other Synchronized Reserve Obligations.

(h) Any amounts credited for Tier 2 Synchronized Reserve in a *Real-time Settlement Interval* in excess of the Synchronized Reserve Market Clearing Price in that *Real-time Settlement Interval* shall be allocated and charged to each Market Participant that does not meet its hourly Synchronized Reserve Obligation in proportion to its purchases of Synchronized Reserve in megawatt-hours during that hour.

(i) In the event the Office of the Interconnection needs to assign more Tier 2 Synchronized Reserve during a *Real-time Settlement Interval* than was estimated as needed at the time the Synchronized Reserve Market Clearing Price was calculated for that *Real-time Settlement Interval* due to a reduction in available Tier 1 Synchronized Reserve, the costs of the excess Tier 2 Synchronized Reserve shall be allocated and charged to those providers of Tier 1 Synchronized Reserve whose available Tier 1 Synchronized Reserve was reduced from the needed amount estimated during the Synchronized Reserve Market Clearing Price calculation, in proportion to the amount of the reduction in Tier 1 Synchronized Reserve availability.

(j) In the event a generation resource or Demand Resource that either has been assigned by the Office of the Interconnection or self-scheduled to provide Tier 2 Synchronized Reserve fails to provide the assigned or self-scheduled amount of Tier 2 Synchronized Reserve in response to a Synchronized Reserve Event, the resource will be credited for Tier 2 Synchronized Reserve capacity in the amount that actually responded for all *Real-time Settlement Intervals* the resource was assigned or self-scheduled Tier 2 Synchronized Reserve on the Operating Day during which the event occurred. The determination of the amount of Synchronized Reserve credited to a resource shall be on an individual resource basis, not on an aggregate basis.

The resource shall refund payments received for Tier 2 Synchronized Reserve it failed to provide. For purposes of determining the amount of the payments to be refunded by a Market Participant, the Office of the Interconnection shall calculate the shortfall of Tier 2 Synchronized Reserve on an individual resource basis unless the Market Participant had multiple resources that were assigned or self-scheduled to provide Tier 2 Synchronized Reserve, in which case the shortfall will be determined on an aggregate basis. For performance determined on an aggregate basis, the response of any resource that provided more Tier 2 Synchronized Reserve than it was assigned or self-scheduled to provide will be used to offset the performance of other resources that provided less Tier 2 Synchronized Reserve than they were assigned or self-scheduled to provide during a Synchronized Reserve Event, as calculated in the PJM Manuals. The determination of a Market Participant's aggregate response shall not be taken into consideration in the determination of the amount of Tier 2 Synchronized Reserve credited to each individual resource.

The amount refunded shall be determined by multiplying the Synchronized Reserve Market Clearing Price by the amount of the shortfall of Tier 2 Synchronized Reserve, measured in megawatts, for all *intervals* the resource was assigned or self-scheduled to provide Tier 2

Synchronized Reserve for a period of time immediately preceding the Synchronized Reserve Event equal to the lesser of the average number of days between Synchronized Reserve Events, or the number of days since the resource last failed to provide the amount of Tier 2 Synchronized Reserve it was assigned or self-scheduled to provide in response to a Synchronized Reserve Event. The average number of days between Synchronized Reserve Events for purposes of this calculation shall be determined by an annual review of the twenty-four month period ending October 31 of the calendar year in which the review is performed, and shall be rounded down to a whole day value. The Office of the Interconnection shall report the results of its annual review to stakeholders by no later than December 31, and the average number of days between Synchronized Reserve Events shall be effective as of the following January 1. The refunded charges shall be allocated as credits to Market Participants based on its pro rata share of the Synchronized Reserve Obligation megawatts less any Tier 1 Synchronized Reserve applied to its Synchronized Reserve Obligation in the hour(s) of the Synchronized Reserve Event for the Reserve Sub-zone or Reserve Zone, except that Market Participants that incur a refund obligation and also have an applicable Synchronized Reserve Obligation during the hour(s) of the Synchronized Reserve Event shall not be included in the allocation of such refund credits. If the event spans multiple hours, the refund credits will be prorated hourly based on the duration of the event within each clock hour.

(k) The magnitude of response to a Synchronized Reserve Event by a generation resource or a Demand Resource, except for Batch Load Demand Resources covered by section 3.2.3A(l), is the difference between the generation resource’s output or the Demand Resource’s consumption at the start of the event and its output or consumption 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output or Demand Resource consumption at the start of the event is defined as the lowest telemetered generator resource output or greatest Demand Resource consumption between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output or a Demand Resource's consumption 10 minutes after the event is defined as the greatest generator resource output or lowest Demand Resource consumption achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter. The response actually credited to a Demand Resource will be reduced by the amount the megawatt consumption of the Demand Resource exceeds the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

(l) The magnitude of response by a Batch Load Demand Resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the start of a Synchronized Reserve Event shall be the difference between (i) the Batch Load Demand Resource’s consumption at the end of the Synchronized Reserve Event and (ii) the Batch Load Demand Resource’s consumption during the minute within the ten minutes after the end of the Synchronized Reserve Event in which the Batch Load Demand Resource’s consumption was highest and for which its consumption in all subsequent minutes within the ten minutes was not less than fifty percent of the consumption in such minute; provided that, the

magnitude of the response shall be zero if, when the Synchronized Reserve Event commences, the scheduled off-cycle stage of the production cycle is greater than ten minutes. .

3.2.3A.001 Non-Synchronized Reserve.

(a) Each Market Participant that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Non-Synchronized Reserve equal to its pro rata share of Non-Synchronized Reserve assigned for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market *Participant's* total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone and Reserve Sub-zone for the hour ("Non-Synchronized Reserve Obligation"). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. A Market Participant *with an* hourly Non-Synchronized Reserve Obligation shall be charged *the pro rata share of the sum of the quantity of Non-Synchronized Reserves provided in each Real-time Settlement Interval times the clearing price for all Real-time Settlement Intervals in the hour associated with that obligation*.

(b) Credits for Non-Synchronized Reserve provided by generation resources that are not operating for energy at the direction of the Office of the Interconnection specifically for the purpose of providing Non-Synchronized Reserve shall be the higher of (i) the Non-Synchronized Reserve Market Clearing Price or (ii) the specific opportunity cost of the generation resource supplying the increment of Non-Synchronized Reserve, as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

(c) The Non-Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each *Real-time Settlement Interval* of the Operating Day. The Non-Synchronized Reserve Market Clearing Price shall be calculated as the 5-minute clearing price. Each 5-minute clearing price shall be calculated as the marginal cost of procuring sufficient Non-Synchronized Reserves and/or Synchronized Reserves in each Reserve Zone or Reserve Sub-zone inclusive of opportunity costs associated with meeting the Primary Reserve Requirement or Extended Primary Reserve Requirement. When the Primary Reserve Requirement or Extended Primary Reserve Requirement in a Reserve Zone or Reserve Sub-zone cannot be met at a price less than or equal to the applicable Reserve Penalty Factor, the 5-minute clearing price for Non-Synchronized Reserve shall be at least greater than or equal to the applicable Reserve Penalty Factor for the Reserve Zone or Reserve Sub-zone, but less than or equal to the Reserve Penalty Factor for the Primary Reserve Requirement for the Reserve Zone or Reserve Sub-zone. If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a *V*oltage *R*eduction *A*ction as described in the PJM Manuals or a *M*anual *L*oad *D*ump *A*ction as described in the PJM Manuals, the 5-minute clearing price shall be the Reserve Penalty Factor for the Primary Reserve Requirement for that Reserve Zone or Reserve Sub-zone.

The Reserve Penalty Factor for the Synchronized Reserve Requirement shall be $850/MWh.

The Reserve Penalty Factor for the Extended Primary Reserve Requirement shall be $300/MWh.

By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to prices exceeding $1,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Primary Reserve Penalty Factors are warranted for subsequent Delivery Year(s).

(d) *For each Real-time Settlement Interval and for* determining the 5-minute Non-Synchronized Reserve clearing price, the unit-specific opportunity cost for a generation resource that is not providing energy because they are providing Non-Synchronized Reserves *will be determined in accordance with the following equation:*

(A x B) – C

Where:

A = *T*he deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order*;*

B =*T*he Locational Marginal Price at the generation bus for the generation resource*; and*
'

C =*T*he applicable offer for energy from the generation resource in the PJM Interchange Energy Market.

(e) In determining the credit under subsection (b) to a resource selected to provide Non-Synchronized Reserve and that follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each *Real-time Settlement Interval* that the Office of the Interconnection requires a generation resource to provide Non- Synchronized Reserve and shall be *in accordance with the following equation:*

(A x B) – C

Where:

A = *T*he deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order*;*

B = *T*he Locational Marginal Price at the generation bus for the generation resource*; and*

C = *T*he applicable offer for energy from the generation resource in the PJM Interchange Energy Market.

(f) Any amounts credited for Non-Synchronized Reserve in a *Real-time Settlement Interval* in excess of the Non-Synchronized Reserve Market Clearing Price in that *Real-time Settlement Interval* shall be allocated and charged to each Market Participant that does not meet its hourly Non-Synchronized Reserve Obligation in proportion to its purchases of Non-Synchronized Reserve in megawatt-hours during that hour.

(g) The magnitude of response to a Non-Synchronized Reserve Event by a generation resource is the difference between the generation resource's output at the start of the event and its output 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output at the start of the event is defined as the lowest telemetered generator resource output between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output 10 minutes after the start of the event is defined as the greatest generator resource output achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

(h) In the event a generation resource that has been assigned by the Office of the Interconnection to provide Non-Synchronized Reserve fails to provide the assigned amount of Non-Synchronized Reserve in response to a Non-Synchronized Reserve Event, the resource will be credited for Non-Synchronized Reserve capacity in the amount that actually responded for the contiguous *Real-time Settlement Interval* the resource was assigned Non-Synchronized Reserve during which the event occurred.

3.2.3A.01 Day-ahead Scheduling Reserves.

(a) The Office of the Interconnection shall satisfy the Day-ahead Scheduling Reserves Requirement by procuring Day-ahead Scheduling Reserves in the Day-ahead Scheduling Reserves Market from Day-ahead Scheduling Reserves Resources, provided that Demand Resources shall be limited to providing the lesser of any limit established by the Reliability First Corporation or SERC, as applicable, or twenty-five percent of the total Day-ahead Scheduling Reserves Requirement. Day-ahead Scheduling Reserves Resources that clear in the Day-ahead Scheduling Reserves Market shall receive a Day-ahead Scheduling Reserves schedule from the Office of the Interconnection for the relevant Operating Day. PJMSettlement shall be the Counterparty to the purchases and sales of Day-ahead Scheduling Reserves in the PJM Interchange Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a self-schedule or self-supply of generation resources by a Market Buyer to satisfy its Day-ahead Scheduling Reserves Requirement.

(b) A Day-ahead Scheduling Reserves Resource that receives a Day-ahead Scheduling Reserves schedule pursuant to subsection (a) of this section shall be paid the hourly Day-ahead Scheduling Reserves Market clearing price for the cleared megawatt quantity of Day-ahead Scheduling Reserves in each hour of the schedule, subject to meeting the requirements of subsection (c) of this section.

(c) To be eligible for payment pursuant to subsection (b) of this section, Day-ahead Scheduling Reserves Resources shall comply with the following provisions:

(i) Generation resources with a start time greater than thirty minutes are required to be synchronized and operating at the direction of the Office of the Interconnection during the resource's Day-ahead Scheduling Reserves schedule and shall have a dispatchable range equal to or greater than the Day-ahead Scheduling Reserves schedule.

(ii) Generation resources and Demand Resources with start times or shut-down times, respectively, equal to or less than 30 minutes are required to respond to dispatch directives from the Office of the Interconnection during the resource's Day-ahead Scheduling Reserves schedule. To meet this requirement the resource shall be required to start or shut down within the specified notification time plus its start or shut down time, provided that such time shall be less than thirty minutes.

(iii) Demand Resources with a Day-ahead Scheduling Reserves schedule shall be credited based on the difference between the resource's MW consumption at the time the resource is directed by the Office of the Interconnection to reduce its load (starting MW usage) and the resource's MW consumption at the time when the Demand Resource is no longer dispatched by PJM (ending MW usage). For the purposes of this subsection, a resource's starting MW usage shall be the greatest telemetered consumption between one minute prior to and one minute following the issuance of a dispatch instruction from the Office of the Interconnection, and a resource's ending MW usage shall be the lowest consumption between one minute before and one minute after a dispatch instruction from the Office of the Interconnection that is no longer necessary to reduce.

(iv) Notwithstanding subsection (iii) above, the credit for a Batch Load Demand Resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the time the resource is directed by the Office of the Interconnection to reduce its load shall be the difference between (i) the "ending MW usage" (as defined above) and (ii) the Batch Load Demand Resource's consumption during the minute within the ten minutes after the time of the "ending MW usage" in which the Batch Load Demand Resource's consumption was highest and for which its consumption in all subsequent minutes within the ten minutes was not less than fifty percent of the consumption in such minute; provided that, the credit shall be zero if, at the time the resource is directed by the Office of the Interconnection to reduce its load, the scheduled off-cycle stage of the production cycle is greater than the timeframe for which the resource was dispatched by PJM.

Resources that do not comply with the provisions of this subsection (c) shall not be eligible to receive credits pursuant to subsection (b) of this section.

(d) The hourly credits paid to Day-ahead Scheduling Reserves Resources satisfying the Base Day-ahead Scheduling Reserves Requirement ("Base Day-ahead Scheduling Reserves credits") shall equal the ratio of the Base Day-ahead Scheduling Reserves Requirement to the Day-ahead Scheduling Reserves Requirement, multiplied by the total credits paid to Day-ahead Scheduling Reserves Resources, and are allocated as Base Day-ahead Scheduling Reserves charges per paragraph (i) below. The hourly credits paid to Day-ahead Scheduling Reserve Resources satisfying the Additional Day-ahead Scheduling Reserve Requirement ("Additional Day-ahead Scheduling Reserves credits") shall equal the ratio of the Additional Day-ahead Scheduling Reserves Requirement to the Day-ahead Scheduling Reserves Requirement, multiplied by the total credits paid to Day-ahead Scheduling Reserves Resources and are allocated as Additional Day-ahead Scheduling Reserves charges per paragraph (ii) below.

(i) A Market Participant's Base Day-ahead Scheduling Reserves charge is equal to the ratio of the Market Participant's hourly obligation to the total hourly obligation of all Market Participants in the PJM Region, multiplied by the Base Day-ahead Scheduling Reserves credits. The hourly obligation for each Market Participant is a megawatt representation of the portion of the Base Day-ahead Scheduling Reserves credits that the Market Participant is responsible for paying to PJM. The hourly obligation is equal to the Market Participant's load ratio share of the total megawatt volume of Base Day-ahead Scheduling Reserves resources (described below), based on the Market Participant's total hourly load (net of operating Behind The Meter Generation, but not to be less than zero) to the total hourly load of all Market Participants in the PJM Region. The total megawatt volume of Base Day-ahead Scheduling Reserves resources equals the ratio of the Base Day-ahead Scheduling Reserves Requirement to the Day-ahead Scheduling Reserves Requirement multiplied by the total volume of Day-ahead Scheduling Reserves megawatts paid pursuant to paragraph (c) of this section. A Market Participant's hourly Day-ahead Scheduling Reserves obligation can be further adjusted by any Day-ahead Scheduling Reserve bilateral transactions.

(ii) Additional Day-ahead Scheduling Reserves credits shall be charged hourly to Market Participants that are net purchasers in the Day-ahead Energy Market based on its positive demand difference ratio share. The positive demand difference for each Market Participant is the difference between its real-time load (net of operating Behind The Meter Generation, but not to be less than zero) and cleared Demand Bids in the Day-ahead Energy Market, net of cleared Increment Offers and cleared Decrement Bids in the Day-ahead Energy Market, when such value is positive. Net purchasers in the Day-ahead Energy Market are those Market Participants that have cleared Demand Bids plus cleared Decrement Bids in excess of its amount of cleared Increment Offers in the Day-ahead Energy Market. If there are no Market Participants with a positive demand difference, the Additional Day-ahead Scheduling Reserves credits are allocated according to paragraph (i) above.

(e) If the Day-ahead Scheduling Reserves Requirement is not satisfied through the operation of subsection (a) of this section, any additional Operating Reserves required to meet the requirement shall be scheduled by the Office of the Interconnection pursuant to Section 3.2.3 of Schedule 1 of this Agreement.

3.2.3B Reactive Services.

(a) A Market Seller providing Reactive Services at the direction of the Office of the Interconnection shall be credited as specified below for the operation of its resource. These provisions are intended to provide payments to generating units when the LMP dispatch algorithms would not result in the dispatch needed for the required reactive service. LMP will be used to compensate generators that are subject to redispatch for reactive transfer limits.

(b) At the end of each Operating Day, where the active energy output of a Market Seller's resource is reduced or suspended at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region, the Market Seller shall be credited according to Sections 3.2.3B(c) & 3.2.3B(d).

(c) A Market Seller providing Reactive Services from either a steam-electric generating unit or combined cycle unit operating in combined cycle mode, where such unit is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override) shall be compensated for lost opportunity cost by receiving a credit in an amount equal to the product of (A) the deviation of the generating unit's output necessary to follow the Office of the Interconnection's signals and the generating unit's expected output level if it had been dispatched in economic merit order, times (B) the Real-time Price at the generation bus for the generating unit, minus (C) the Total Lost Opportunity Cost Offer, provided that the resulting outcome is greater than $0.00. This equation is represented as (A*B) - C.

(d) A Market Seller providing Reactive Services from either a combustion turbine unit or combined cycle unit operating in simple cycle mode that is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost, limited to the lesser of the unit's Economic Maximum or the unit's Generation Resource Maximum Output, if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection as directed by the PJM dispatcher, then the Market Seller shall be credited in a manner consistent with that described above in Section 3.2.3B(c) for a steam unit or a combined cycle unit operating in combined cycle mode.

(e) At the end of each Operating Day, where the active energy output of a Market Seller's unit is increased at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region and the offered price of the energy is above the real-time LMP at the unit's bus, the Market Seller shall be credited according to Section 3.2.3B(f).

(f) A Market Seller providing Reactive Services from either a steam-electric generating unit, combined cycle unit or combustion turbine unit, where such unit is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the real time LMP at the unit's bus is lower than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall receive a credit hourly in an amount equal to {(AG - LMPDMW) x (UB - URTLMP)}where:

AG equals the actual output of the unit;

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the real time LMP at the unit's bus and adjusted for any Regulation or Tier 2 Synchronized Reserve assignments;

UB equals the unit offer for that unit for which output is increased, determined according to the lesser of the Final Offer or Committed Offer;

URTLMP equals the real time LMP at the unit's bus; and

where UB - URTLMP shall not be negative.

(g) A Market Seller providing Reactive Services from a hydroelectric resource where such resource is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the output of such resource is altered from the schedule submitted by the Market Seller for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(h) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for lost opportunity cost associated with following the Office of the Interconnection's dispatch instructions to reduce or suspend a unit's output for the purpose of maintaining reactive reliability, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of such alternate lost opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of alternate lost opportunity cost compensation, the Office of the Interconnection shall invoice the Market *Participant* accordingly. If the Market Monitoring Unit disagrees with the modified amount of alternate lost opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(i) The amount of Synchronized Reserve provided by generating units maintaining reactive reliability shall be counted as Synchronized Reserve satisfying the overall PJM Synchronized Reserve requirements. Operators of these generating units shall be notified of such provision, and to the extent a generating unit's operator indicates that the generating unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in Section 3.2.3A regarding provision of Tier 2 Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated to provide Reactive Services also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the Synchronized Reserve Market Clearing Price for each *Real-time Settlement Interval* a generating unit provided synchronous condensing multiplied by the amount of Synchronized reserve provided by the synchronous condenser or (ii) the sum of (A) the generating unit's cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the product of MW energy usage for providing synchronous condensing multiplied by the real time LMP at the generating unit's bus, (C) the generating unit's startup-cost of providing synchronous condensing, and (D) the unit-specific lost opportunity cost of the generating resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated to provide Reactive Services was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generating unit's cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to subsection (l) below.

(j) A Market Seller's pool scheduled steam-electric generating unit or combined cycle unit operating in combined cycle mode, that is not committed to operate in the Day-ahead Market, but that is directed by the Office of the Interconnection to operate solely for the purpose of maintaining reactive reliability, at the request of the Office of the Interconnection, shall be credited in the amount of the unit's offered price for start-up and no-load fees. The unit also shall receive, if applicable, compensation in accordance with Sections 3.2.3B(e)-(f).

(k) The sum of the foregoing credits as specified in Sections 3.2.3B(b)-(j) shall be the cost of Reactive Services for the purpose of maintaining reactive reliability for the Operating Day and shall be separately determined for each transmission zone in the PJM Region based on whether the resource was dispatched for the purpose of maintaining reactive reliability in such transmission zone.

(l) The cost of Reactive Services for the purpose of maintaining reactive reliability in a transmission zone in the PJM Region for each Operating Day shall be allocated and charged to each Market Participant in proportion to its deliveries of energy to load (net of operating Behind The Meter Generation) in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

(m) Generating units receiving dispatch instructions from the Office of the Interconnection under the expectation of increased actual or reserve reactive shall inform the Office of the Interconnection dispatcher if the requested reactive capability is not achievable. Should the operator of a unit receiving such instructions realize at any time during which said instruction is effective that the unit is not, or likely would not be able to, provide the requested amount of reactive support, the operator shall as soon as practicable inform the Office of the Interconnection dispatcher of the unit's inability, or expected inability, to provide the required reactive support, so that the associated dispatch instruction may be cancelled. PJM Performance Compliance personnel will audit operations after-the-fact to determine whether a unit that has altered its active power output at the request of the Office of the Interconnection has provided the actual reactive support or the reactive reserve capability requested by the Office of the Interconnection. PJM shall utilize data including, but not limited to, historical reactive performance and stated reactive capability curves in order to make this determination, and may withhold such compensation as described above if reactive support as requested by the Office of the Interconnection was not or could not have been provided.

3.2.3C Synchronous Condensing for Post-Contingency Operation.

(a) Under normal circumstances, PJM operates generation out of merit order to control contingency overloads when the flow on the monitored element for loss of the contingent element ("contingency flow") exceeds the long-term emergency rating for that facility, typically a 4-hour or 2-hour rating. At times however, and under certain, specific system conditions, PJM does not operate generation out of merit order for certain contingency overloads until the contingency flow on the monitored element exceeds the 30-minute rating for that facility ("post-contingency operation"). In conjunction with such operation, when the contingency flow on such element exceeds the long-term emergency rating, PJM operates synchronous condensers in the areas affected by such constraints, to the extent they are available, to provide greater certainty that such resources will be capable of producing energy in sufficient time to reduce the flow on the monitored element below the normal rating should such contingency occur.

(b) The amount of Synchronized Reserve provided by synchronous condensers associated with post-contingency operation shall be counted as Synchronized Reserve satisfying the PJM Synchronized Reserve requirements. Operators of these generation units shall be notified of such provision, and to the extent a generation unit's operator indicates that the generation unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in Section 3.2.3A regarding provision of Tier 2 Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated in conjunction with post-contingency operation also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing in conjunction with post-contingency operation at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the Synchronized Reserve Market Clearing Price for each *applicable interval* a generation resource provided synchronous condensing multiplied by the amount of Synchronized Reserve provided by the synchronous condenser or (ii) the sum of (A) the generation resource's *applicable interval* cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the *applicable interval* product of the megawatts of energy used to provide synchronous condensing multiplied by the real-time LMP at the generation bus of the generation resource, (C) the generation resource's start-up cost of providing synchronous condensing, and (D) the unit-specific lost opportunity cost of the generation resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated in association with post-contingency constraint control was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generation unit's cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to subsection (d) below.

(c) The sum of the foregoing credits as specified in section 3.2.3C(b) shall be the cost of synchronous condensers associated with post-contingency operations for the Operating Day and shall be separately determined for each transmission zone in the PJM Region based on whether the resource was dispatched in association with post-contingency operation in such transmission zone.

(d) The cost of synchronous condensers associated with post-contingency operations in a transmission zone in the PJM Region for each Operating Day shall be allocated and charged to each Market Participant in proportion to its deliveries of energy to load (net of operating Behind The Meter Generation) in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

3.2.4 Transmission Congestion Charges.

Each Market Buyer shall be assessed Transmission Congestion Charges as specified in Section 5 of this Schedule.

3.2.5 Transmission Loss Charges.

Each Market Buyer shall be assessed Transmission Loss Charges as specified in Section 5 of this Schedule.

3.2.6 Emergency Energy.

(a) When the Office of the Interconnection has implemented Emergency procedures, resources offering Emergency energy are eligible to set real-time Locational Marginal Prices, capped at the energy offer cap plus the sum of the applicable Reserve Penalty Factors for the Synchronized Reserve Requirement and Primary Reserve Requirement, provided that the Emergency energy is needed to meet demand in the PJM Region.

(b) Market Participants shall be allocated a proportionate share of the net cost of Emergency energy purchased by the Office of the Interconnection. Such allocated share during each *applicable interval* of such Emergency energy purchase shall be in proportion to the amount of each Market Participant's real-time deviation from its net *withdrawals and injections* in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market sales. This deviation shall not include any reduction or suspension of output of pool scheduled resources requested by PJM to manage an Emergency within the PJM Region.

(c) Net revenues in excess of Real-time Prices attributable to sales of energy in connection with Emergencies to other Control Areas shall be credited to Market Participants during each *applicable interval* of such Emergency energy sale in proportion to the sum of (i) each Market Participant's real-time deviation from its net *withdrawals and injections* in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market sales, and (ii) each Market Participant's energy sales from within the PJM Region to entities outside the PJM Region that have been curtailed by PJM.

(d) The net costs or net revenues associated with sales or purchases of energy in connection with a Minimum Generation Emergency in the PJM Region, or in another Control Area, shall be allocated during each *applicable interval* of such Emergency sale or purchase to each Market Participant in proportion to the amount of each Market Participant's real-time deviation from its net *withdrawals and injections* in the Day-ahead Market, whenever that deviation increases the Market Participant's spot market sales or decreases its spot market purchases.

3.2.7 Billing.

(a) PJMSettlement shall prepare a billing statement each billing cycle for each Market *Participant* in accordance with the charges and credits specified in Sections 3.2.1 through 3.2.6 of this Schedule, and showing the net amount to be paid or received by the Market *Participant*. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts and completion of the Market *Participant*'s internal accounting.

(b) If deliveries to a Market *Participant* that has PJM Interchange meters in accordance with Section 14 of the Operating Agreement include amounts delivered for a Market Participant that does not have PJM Interchange meters separate from those of the metered Market *Participant*, PJMSettlement shall prepare a separate billing statement for the unmetered Market Participant based on the allocation of deliveries agreed upon between the Market *Participant* and the unmetered Market Participant specified by them to the Office of the Interconnection.

Section(s) of the
PJM Operating Agreement

(Marked / Redline Format)

3.2 Market *Settlements.*

If a dollar-per-MW-hour value is applied in a calculation under this section 3.2 where the interval of the value produced in that calculation is less than an hour, then for purposes of that calculation the dollar-per-MW hour value is divided by the number of Real-time Settlement Intervals in the hour.

3.2.1 Spot Market Energy.

(a) The Office of the Interconnection shall calculate System Energy Prices in the form of Day-ahead System Energy Prices and Real-time System Energy Prices for the PJM Region, in accordance with Section 2 of this Schedule.

(b) *Each* Market *Participant* shall be charged for all *of its Market Participant Energy Withdrawals* scheduled in the Day-ahead Energy Market at the Day-ahead System Energy Price *to be served in the PJM Interchange Energy Market.*

(c) *Each* Market *Participant* shall be paid for all *of its Market Participant Energy Injections* scheduled in the Day-ahead Energy Market at the Day-ahead System Energy Price *to be delivered to the PJM Interchange Energy Market*.

(d) For each Day-ahead Settlement Interval during an Operating Day, the Office of the Interconnection shall calculate Spot Market Energy charges for each Market Participant as the difference between the sum of its Market Participant Energy Withdrawals scheduled times the Day-ahead System Energy Price and the sum of its Market Participant Energy Injections scheduled times the Day-ahead System Energy Price.

(e) For each Real-time Settlement Interval during an Operating Day, the Office of the Interconnection shall calculate Spot Market Energy charges for each Market Participant as the difference between the sum of its real-time Market Participant Energy Withdrawals less its scheduled Market Participant Energy Withdrawals times the Real-time System Energy Price and the sum of its real-time Market Participant Energy Injections less scheduled Market Participant Energy Injections times the Real-time System Energy Price. The Revenue Data for Settlements determined for each Real-time Settlement Interval in accordance with section 3.1A of this Schedule shall be used in determining the real-time Market Participant Energy Withdrawals and Market Participant Energy Injections used to calculate Spot Market Energy charges under this subsection (e).

(f) For pool External Resources, the Office of the Interconnection shall model, based on an appropriate flow analysis, the megawatts of real-time energy injections to be delivered from each such resource to the corresponding Interface Pricing Point between adjacent Control Areas and the PJM Region

3.2.2 Regulation.

(a) Each Market *Participant* that is a Load Serving Entity in a Regulation Zone shall have an hourly Regulation objective equal to its pro rata share of the Regulation requirements of such Regulation Zone for the hour, based on the Market *Participant's* total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Regulation Zone for the hour ("Regulation Obligation"). A Market *Participant with an* hourly Regulation *O*bligation shall be charged the *pro rata share of the sum of the quantity of regulation provided in each Real-time Settlement Interval times the clearing price for all Real-time Settlement Intervals in the hour associated with that obligation.*

(b) Each Market *Participant supplying Regulation in a Regulation Zone at the direction of the Office of the Interconnection* shall be credited for each of its resources such that the calculated credit for each increment of Regulation provided by each resource shall be the higher of: (i) the Regulation market-clearing price; or (ii) the sum of the applicable Regulation offers for a resource determined pursuant to Section 3.2.2A.1 of this Schedule, the unit-specific shoulder hour opportunity costs described in subsection (e) of this section, the unit-specific inter-temporal opportunity costs, and the unit-specific opportunity costs discussed in subsection (d) of this section.

(c) The total Regulation market-clearing price in each Regulation Zone shall be determined *for each Real-time Settlement Interval.* The total Regulation market-clearing price shall include: (i) the performance Regulation market-clearing price in a Regulation Zone that shall be calculated in accordance with subsection (g) of this section; (ii) the capability Regulation market-clearing price that shall be calculated in accordance with subsection (h) of this section; and (iii) a Regulation resource's unit-specific opportunity costs during the 5-minute period, determined as described in subsection (d) below, divided by the unit-specific benefits factor described in subsection (j) of this section and divided by the historic accuracy score of the resource from among the resources selected to provide Regulation. A resource's Regulation offer by any Market Seller that fails the three-pivotal supplier test set forth in section 3.2.2A.1 of this Schedule shall not exceed the cost of providing Regulation from such resource, plus twelve dollars, as determined pursuant to the formula in section 1.10.1A(e) of this Schedule.

(d) In determining the Regulation 5-minute clearing price for each Regulation Zone, the estimated unit-specific opportunity costs of a generation resource offering to sell Regulation in each regulating hour, except for hydroelectric resources, shall be equal to the product of (i) the deviation of the set point of the generation resource that is expected to be required in order to provide Regulation from the generation resource's expected output level if it had been dispatched in economic merit order times, (ii) the absolute value of the difference between the expected Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource) in the PJM Interchange Energy Market.

For hydroelectric resources offering to sell Regulation in a regulating hour, the estimated unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the full value of the Locational Marginal Price at that generation bus for each megawatt of Regulation capability.

The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and has a day-ahead megawatt commitment greater than zero shall be equal to the product of (i) the deviation of the set point of the hydroelectric resource that is expected to be required in order to provide Regulation from the hydroelectric resource's expected output level if it had been dispatched in economic merit order times (ii) the difference between the expected Locational Marginal Price at the generation bus for the hydroelectric resource and the average of the Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating. Estimated opportunity costs shall be zero for hydroelectric resources for which the average Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period, excluding those *Real-time Settlement Intervals* during which all available units at the hydroelectric resource were operating is higher than the actual Locational Marginal Price at the generator bus for the *Real-time Settlement Interval*.

The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead megawatt commitment greater than zero shall be equal to the product of (i) the deviation of the set point of the hydroelectric resource that is expected to be required in order to provide Regulation from the hydroelectric resource's expected output level if it had been dispatched in economic merit order times (ii) the difference between the average of the Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating and the expected Locational Marginal Price at the generation bus for the hydroelectric resource. Estimated opportunity costs shall be zero for hydroelectric resources for which the actual Locational Marginal Price at the generator bus for the *Real-time Settlement Interval* is higher than the average Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period, excluding those *Real-time Settlement Intervals* during which all available units at the hydroelectric resource were operating.

For the purpose of committing resources and setting Regulation market clearing prices, the Office of the Interconnection shall utilize day-ahead Locational Marginal Prices to calculate opportunity costs for hydroelectric resources. For the purposes of settlements, the Office of the Interconnection shall utilize the real-time Locational Marginal Prices to calculate opportunity costs for hydroelectric resources.

Estimated opportunity costs for Demand Resources to provide Regulation are zero.

(e) In determining the credit under subsection (b) to a Market *Participant* selected to provide Regulation in a Regulation Zone and that actively follows the Office of the Interconnection's Regulation signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for *(1)* each *Real-time Settlement Interval* that the Office of the Interconnection requires a generation resource to provide Regulation, and *(2)* the *last three Real-time Settlement Intervals* of the preceding shoulder hour and the *first three Real-time*

Settlement Intervals of the following shoulder hour *in accordance with the PJM Manuals and below*.

The unit-specific opportunity cost incurred during the *Real-time Settlement Interval* in which the Regulation obligation is fulfilled shall be equal to the product of (i) the deviation of the generation resource‘s output necessary to follow the Office of the Interconnection‘s Regulation signals from the generation resource‘s expected output level if it had been dispatched in economic merit order times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the actual megawatt level of the resource when the actual megawatt level is within the tolerance defined in the PJM Manuals for the Regulation set point, or at the Regulation set point for the resource when it is not within the corresponding tolerance) in the PJM Interchange Energy Market. Opportunity costs for Demand Resources to provide Regulation are zero.

The unit-specific opportunity costs associated with uneconomic operation during *each of* the preceding *three Real-time Settlement Intervals of the* shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the initial regulating *Real-time Settlement Interval* in order to provide Regulation and the resource‘s expected output in *each of the* preceding *three Real-time Settlement Intervals of the* shoulder hour times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in *each of* the preceding *three Real-time Settlement Intervals of the* shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in the initial regulating *Real-time Settlement Interval*) in the PJM Interchange Energy Market, all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

The unit-specific opportunity costs associated with uneconomic operation during *each of* the following *three Real-time Settlement Intervals of the* shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the final regulating *Real-time Settlement Interval* in order to provide Regulation and the resource‘s expected output in *each of* the following *three Real-time Settlement Intervals of the* shoulder hour times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in *each of* the following *three Real-time Settlement Intervals of the* shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in final regulating hour) in the PJM Interchange Energy Market all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

(f) Any amounts credited for Regulation in an hour in excess of the Regulation market-clearing price in that hour shall be allocated and charged to each Market *Participant* in a Regulation Zone that does not meet its hourly Regulation obligation in proportion to its purchases of Regulation in such Regulation Zone in megawatt-hours during that hour.

(g) To determine the performance Regulation market-clearing price for each Regulation Zone, the Office of the Interconnection shall adjust the submitted performance offer for each resource in accordance with the historical performance of that resource, the amount of Regulation that resource will be dispatched based on the ratio of control signals calculated by the Office of the Interconnection, and the unit-specific benefits factor described in subsection (j) of this section for which that resource is qualified. The maximum adjusted performance offer of all cleared resources will set the performance Regulation market-clearing price.

The owner of each Regulation resource that actively follows the Office of the Interconnection's Regulation signals and instructions, will be credited for Regulation performance by multiplying the assigned MW(s) by the performance Regulation market-clearing price, by the ratio between the requested mileage for the Regulation dispatch signal assigned to the Regulation resource and the Regulation dispatch signal assigned to traditional resources, and by the Regulation resource's accuracy score calculated in accordance with subsection (k) of this section.

(h) The Office of the Interconnection shall divide each Regulation resource's capability offer by the unit-specific benefits factor described in subsection (j) of this section and divided by the historic accuracy score for the resource for the purposes of committing resources and setting the market clearing prices.

The Office of the Interconnection shall calculate the capability Regulation market-clearing price for each Regulation Zone by subtracting the performance Regulation market-clearing price described in subsection (g) from the total Regulation market clearing price described in subsection (c). This residual sets the capability Regulation market clearing price for that market *Real-time Settlement Interval*.

The owner of each Regulation resource that actively follows the Office of the Interconnection's Regulation signals and instructions will be credited for Regulation capability based on the assigned MW and the capability Regulation market-clearing price multiplied by the Regulation resource's accuracy score calculated in accordance with subsection (k) of this section.

(i) In accordance with the processes described in the PJM Manuals, the Office of the Interconnection shall: (i) calculate inter-temporal opportunity costs for each applicable resource; (ii) include such inter-temporal opportunity costs in each applicable resource's offer to sell frequency Regulation service; and (iii) account for such inter-temporal opportunity costs in the Regulation market-clearing price.

(j) The Office of the Interconnection shall calculate a unit-specific benefits factor for each of the dynamic Regulation signal and traditional Regulation signal in accordance with the PJM Manuals. Each resource shall be assigned a unit-specific benefits factor based on their order in the merit order stack for the applicable Regulation signal. The unit-specific benefits factor is the point on the benefits factor curve that aligns with the last megawatt, adjusted by historical performance, that resource will add to the dynamic resource stack. The unit-specific benefits factor for the traditional Regulation signal shall be equal to one.

(k) The Office of the Interconnection shall calculate each Regulation resource's accuracy score. The accuracy score shall be the average of a delay score, correlation score, and energy score for each ten second interval. For purposes of setting the interval to be used for the correlation score and delay scores, PJM will use the maximum of the correlation score plus the delay score for each interval.

The Office of the Interconnection shall calculate the correlation score using the following statistical correlation function (r) that measures the delay in response between the Regulation signal and the resource change in output:

$$\text{Correlation Score} = r_{\text{Signal,Response}(\delta,\delta+5\text{ Min});\ \delta=0\text{ to }5\text{ Min}}$$

where δ is delay.

The Office of the Interconnection shall calculate the delay score using the following equation:

$$\text{Delay Score} = \text{Abs}\left((\delta - 5\text{ Minutes}) / (5\text{ Minutes})\right).$$

The Office of the Interconnection shall calculate a*n* energy score as a function of the difference in the energy provided versus the energy requested by the Regulation signal while scaling for the number of samples. The energy score is the absolute error (ε) as a function of the resource's Regulation capacity using the following equations:

$$\text{Energy Score} = 1 - 1/n \sum \text{Abs (Error)};$$

Error = Average of Abs ((Response - Regulation Signal) / (Hourly Average Regulation Signal)); and

n = the number of samples in the hour and the energy.

The Office of the Interconnection shall calculate an accuracy score for each Regulation resource that is the average of the delay score, correlation score, and energy score for a five-minute period using the following equation where the energy score, the delay score, and the correlation score are each weighted equally:

Accuracy Score = max ((Delay Score) + (Correlation Score)) + (Energy Score). The historic accuracy score will be based on a rolling average of the *Real-time Settlement Interval* accuracy scores, with consideration of the qualification score, as defined in the PJM Manuals.

3.2.2A Offer Price Caps.

3.2.2A.1 Applicability.

(a) Each hour, the Office of the Interconnection shall conduct a three-pivotal supplier test as described in this section. Regulation offers from Market Sellers that fail the three-pivotal supplier test shall be capped in the hour in which they failed the test at their cost based offers as determined pursuant to section 1.10.1A(e) of this Schedule. A Regulation supplier fails the three-pivotal supplier test in any hour in which such Regulation supplier and the two largest other Regulation suppliers are jointly pivotal.

(b) For the purposes of conducting the three-pivotal supplier test pursuant to this section, the following applies:

(i) The three-pivotal supplier test will include in the definition of available supply all offers from resources capable of satisfying the Regulation requirement of the PJM Region multiplied by the historic accuracy score of the resource and multiplied by the unit-specific benefits factor for which the capability cost-based offer plus the performance cost-based offer plus any eligible opportunity costs is no greater than 150 percent of the clearing price that would be calculated if all offers were limited to cost (plus eligible opportunity costs).

(ii) The three-pivotal supplier test will apply on a Regulation supplier basis (i.e. not a resource by resource basis) and only the Regulation suppliers that fail the three-pivotal supplier test will have their Regulation offers capped. A Regulation supplier for the purposes of this section includes corporate affiliates. Regulation from resources controlled by a Regulation supplier or its affiliates, whether by contract with unaffiliated third parties or otherwise, will be included as Regulation of that Regulation supplier. Regulation provided by resources owned by a Regulation supplier but controlled by an unaffiliated third party, whether by contract or otherwise, will be included as Regulation of that third party.

(iii) Each supplier shall be ranked from the largest to the smallest offered megawatt of eligible Regulation supply adjusted by the historic performance of each resource and the unit-specific benefits factor. Suppliers are then tested in order, starting with the three largest suppliers. For 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 Regulation requirement for the hour to determine the residual supply index. Where the residual supply index for three pivotal suppliers 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 third supplier result in a residual supply index greater than 1.0, at which point the remaining suppliers pass the test. Any resource owner that fails the three-pivotal supplier test will be offer-capped.

3.2.3 Operating Reserves.

(a) A Market Seller's pool-scheduled resources capable of providing Operating Reserves shall be credited as specified below based on the applicable offer for the operation of such resource, provided that the resource was available for the entire time specified in the Offer Data for such resource. To the extent that Section 3.2.3A.01 of Schedule 1 of this Agreement does not meet the Day-ahead Scheduling Reserves Requirement, the Office of the Interconnection shall schedule additional Operating Reserves pursuant to Section 1.7.17 and 1.10 of Schedule 1 of this Agreement. In addition the Office of the Interconnection shall schedule Operating Reserves pursuant to those sections to satisfy any unforeseen Operating Reserve requirements that are not reflected in the Day-ahead Scheduling Reserves Requirement.

(b) The following determination shall be made for each pool-scheduled resource that is scheduled in the Day-ahead Energy Market: the total offered price for Start-up Costs and No-load Costs and energy, determined on the basis of the resource's scheduled output, shall be compared to the total value of that resource's energy – as determined by the Day-ahead Energy Market and the Day-ahead Prices applicable to the relevant generation bus in the Day-ahead Energy Market. PJM shall also (i) determine whether any resources were scheduled in the Day-ahead Energy Market to provide Black Start service, Reactive Services or transfer interface control during the Operating Day because they are known or expected to be needed to maintain system reliability in a Zone during the Operating Day in order to minimize the total cost of Operating Reserves associated with the provision of such services and reflect the most accurate possible expectation of real-time operating conditions in the day-ahead model, which resources would not have otherwise been committed in the day-ahead security-constrained dispatch and (ii) report on the day following the Operating Day the megawatt quantities scheduled in the Day-ahead Energy Market for the above-enumerated purposes for the entire RTO.

Except as provided in Section 3.2.3(n), if the total offered price for Start-up Costs (shutdown costs for Demand Resources) and No-load Costs and energy summed over all *Day-ahead Settlement Intervals* exceeds the total value summed over all *Day-ahead Settlement Intervals*, the difference shall be credited to the Market Seller.

The Office of the Interconnection shall apply any balancing Operating Reserve credits allocated pursuant to this Section 3.2.3(b) to real-time deviations or real-time load share plus exports, pursuant to Section 3.2.3(p), depending on whether the balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

(i) For resources scheduled by the Office of the Interconnection during the reliability analysis for an Operating Day, the associated balancing Operating Reserve credits shall be allocated based on the reason the resource was scheduled according to the following provisions:

(A) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to operate in real-time to augment the physical resources committed in the Day-ahead Energy Market to meet the forecasted real-time load plus the Operating Reserve requirement, the associated balancing Operating Reserve credits, identified as RA Credits for Deviations, shall be allocated to real-time deviations.

(B) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to maintain system reliability, the associated balancing Operating Reserve credits, identified as RA Credits for Reliability, shall be allocated according to ratio share of real time load plus export transactions.

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing Operating Reserves, the associated balancing Operating Reserve credits shall be segmented and separately allocated pursuant to subsections 3.2.3(b)(i)(A) or 3.2.3(b)(i)(B) hereof. Balancing Operating Reserve credits for such resources will be identified in the same manner as units committed during the reliability analysis pursuant to subsections 3.2.3(b)(i)(A) and 3.2.3(b)(i)(B) hereof.

(ii) For resources scheduled during an Operating Day, the associated balancing Operating Reserve credits shall be allocated according to the following provisions:

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Operating Reserve credits, identified as RT Credits for Reliability, shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, credits will be applied pursuant to this section only if the LMP at the resource's bus does not meet or exceed the applicable offer of the resource for at least four 5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the credits for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category (RT Credits for Reliability or RT Credits for Deviations) as identified for the Operating Reserves for the other discrete clock hours.

(B) If the Office of the Interconnection directs a resource not covered by Section 3.2.3(b)(ii)(A) hereof to operate in real-time during an Operating Day, the associated balancing Operating Reserve credits, identified as RT Credits for Deviations, shall be allocated according to real-time deviations from day-ahead schedules.

(iii) PJM shall post on its Web site the aggregate amount of MWs committed that meet the criteria referenced in subsections (b)(i) and (b)(ii) hereof.

(c) The sum of the foregoing credits calculated in accordance with Section 3.2.3(b) plus any unallocated charges from Section 3.2.3(h) and 5.1.7, and any shortfalls paid pursuant to the Market Settlement provision of the Day-ahead Economic Load Response Program, shall be the cost of Operating Reserves in the Day-ahead Energy Market.

(d) The cost of Operating Reserves in the Day-ahead Energy Market shall be allocated and charged to each Market Participant in proportion to the sum of its (i) scheduled load (net of Behind The Meter Generation expected to be operating, but not to be less than zero), ~~and~~ accepted Decrement Bids in the Day-ahead Energy Market in megawatt-hours for that Operating Day, and the scheduled megawatt-hours at the specified sink of an accepted Up-to Congestion Transaction; and (ii) scheduled energy sales in the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours for that Operating Day, but not including its bilateral transactions that are Dynamic Transfers to load outside such area pursuant to Section 1.12, except to the extent PJM scheduled resources to provide Black Start service, Reactive Services or transfer interface control. The cost of Operating Reserves in the Day-ahead Energy Market for resources scheduled to provide Black Start service for the Operating Day which resources would not have otherwise been committed in the day-ahead security constrained dispatch shall be allocated by ratio share of the monthly transmission use of each Network Customer or Transmission Customer serving Zone Load or Non-Zone Load, as determined in accordance with the formulas contained in Schedule 6A of the PJM Tariff. The cost of Operating Reserves in the Day-ahead Energy Market for resources scheduled to provide Reactive Services or transfer interface control because they are known or expected to be needed to maintain system reliability in a Zone during the Operating Day and would not have otherwise been committed in the day-ahead security constrained dispatch shall be allocated and charged to each Market Participant in proportion to the sum of its real-time deliveries of energy to load (net of operating Behind The Meter Generation) in such Zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such Zone.

(e) At the end of each Operating Day, the following determination shall be made for each synchronized pool-scheduled resource of each Market Seller that operates as requested by the Office of the Interconnection. For each calendar day, pool-scheduled resources in the Real-time Energy Market shall be made whole for each of the following Segments: 1) the greater of their day-ahead schedules *and* minimum run time *specified at the time of commitment* (minimum down time *specified at the time of commitment* for Demand Resources); and 2) any block of *Real-time Settlement Intervals* the resource operates at PJM's direction in excess of the greater of its day-ahead schedule *and* minimum run time *specified at the time of commitment* (minimum down time *specified at the time of commitment* for Demand Resources). For each calendar day, and for each synchronized start of a generation resource or PJM-dispatched economic load reduction, there will be a maximum of two Segments for each resource. Segment 1 will be the greater of the day-ahead schedule and minimum run time *specified at the time of commitment* (minimum down time *specified at the time of commitment* for Demand Resources) and Segment 2 will include the remainder of the contiguous *Real-time Settlement Intervals* when the resource is operating at the direction of the Office of the Interconnection, provided that a segment is limited to the Operating Day in which it commenced and cannot include any part of the following Operating Day.

A Generation Capacity Resource that operates outside of its unit-specific parameters will not receive Operating Reserve Credits nor be made whole for such operation when not dispatched by the Office of the Interconnection, unless the Market Seller of the Generation Capacity Resource can justify to the Office of the Interconnection that operation outside of such unit-specific parameters was the result of an actual constraint. Such Market Seller shall provide to the Market Monitoring Unit and the Office of the Interconnection its request to receive Operating Reserve Credits and/or to be made whole for such operation, along with documentation explaining in detail the reasons for operating its resource outside of its unit-specific parameters, within thirty calendar days following the issuance of billing statement for the Operating Day. The Market Seller shall also respond to additional requests for information from the Market Monitoring Unit and the Office of the Interconnection. The Market Monitoring Unit shall evaluate such request for compensation and provide its determination of whether there was an exercise of market power to the Office of the Interconnection by no later than twenty-five calendar days after receiving the Market Seller's request for compensation. The Office of the Interconnection shall make its determination whether the Market Seller justified that it is entitled to receive Operating Reserve Credits and/or be made whole for such operation of its resource for the day(s) in question, by no later than thirty calendar days after receiving the Market Seller's request for compensation.

Credits received pursuant to this section shall be equal to the positive difference between a resource's Total Operating Reserve Offer, and the total value of the resource's energy for hours in the Day-ahead Energy Market that correspond to five-minute intervals in which the resource is operated in real-time pursuant to the Office of the Interconnection's direction, plus any credit or change for quantity deviations, at PJM dispatch direction (excluding quantity deviations caused by an increase in the Market Seller's Real-time Offer), from the Day-ahead Energy Market during the Operating Day at the real-time LMP(s) applicable to the relevant generation bus in the Real-time Energy Market. The foregoing notwithstanding, credits for segment 2 shall exclude start up (shutdown costs for Demand Resources) costs for generation resources.

Except as provided in Section 3.2.3(m), if the total offered price exceeds the total value, the difference less any credit as determined pursuant to Section 3.2.3(b), and less any amounts credited for Synchronized Reserve in excess of the Synchronized Reserve offer plus the resource's opportunity cost, and less any amounts credited for Non-Synchronized Reserve in excess of the Non-Synchronized Reserve offer plus the resource's opportunity cost, and less any amounts credited for providing Reactive Services as specified in Section 3.2.3B, and less any amounts for Day-ahead Scheduling Reserve in excess of the Day-ahead Scheduling Reserve offer plus the resource's opportunity cost, shall be credited to the Market Seller.

Synchronized Reserve, Non-Synchronized Reserve, and *Real-time Settlement Interval share of the* Day-ahead Scheduling Reserve credits applied against Operating Reserve credits pursuant to this section shall be netted against the Operating Reserve credits earned in the corresponding *Real-time Settlement Interval*(s) in which the Synchronized Reserve, Non-Synchronized Reserve, and Day-ahead Scheduling Reserve credits accrued, provided that for condensing combustion turbines, Synchronized Reserve credits will be netted against the total Operating Reserve credits accrued during each *Real-time Settlement Interval* the unit operates in condensing and generation mode.

(f) A Market Seller of a unit not defined in subsection (f-1), (f-2), or (f-4) hereof (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited *for each Real-time Settlement Interval* in an amount equal to the product of (A) the deviation of the generating unit's output necessary to follow the Office of the Interconnection's signals and the generating unit's expected output level if it had been dispatched in economic merit order, times (B) the Locational Marginal Price at the generation bus for the generating unit, minus (C) the Total Lost Opportunity Cost Offer, provided that the resulting outcome is greater than $0.00. This equation is represented as (A*B) - C.

(f-1) With the exception of Market Sellers of Flexible Resources that submit a Real-time Offer greater than their resource's Committed Offer in the Day-ahead Energy Market, a Market Seller of a Flexible Resource shall be compensated for lost opportunity cost, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Generation Resource Maximum Output, if either of the following conditions occur:

(i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as directed by the PJM dispatcher), then the Market Seller shall be credited in a manner consistent with that described in section 3.2.3 (f).

(ii) *If the unit* is scheduled to produce energy in the Day-ahead Energy Market *for a Day-ahead Settlement Interval*, but the unit is not called on by the Office of the Interconnection and does not operate in *the corresponding Real-time Settlement Interval(s)*, then the Market Seller shall be credited in an amount equal to the higher of:

1) the product of (A) the amount of megawatts committed in the Day-ahead Energy Market for the generating unit, and (B) the Real-time Price at the generation bus for the generating unit, minus the sum of (C) the Total Lost Opportunity Cost Offer plus No-load Costs, plus (D) the Start-up Cost, divided by the *Real-time Settlement Intervals* committed for each set of contiguous hours for which the unit was scheduled in Day-ahead Energy Market. This equation is represented as (A*B) - (C+D). The startup cost, (D), shall be excluded from this calculation if the unit operates in real time following the Office of the Interconnection's direction during any portion of the set of contiguous hours for which the unit was scheduled in Day-ahead Energy Market, or

2) the Real-time Price at the unit's bus minus the Day-ahead Price at the unit's bus, multiplied by the number of megawatts committed in the Day-ahead Energy Market for the generating unit.

Market Sellers of Flexible Resources that submit a Real-time Offer greater than their resource's Committed Offer in the Day-ahead Energy Market shall not be eligible to receive compensation for lost opportunity costs under any applicable provisions of Schedule 1 of this Agreement.

(f-2) A Market Seller of a hydroelectric resource that is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), the output of which is altered at the request of the Office of the Interconnection from the schedule submitted by the owner, due to a transmission constraint or other reliability issue, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(f-3) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for opportunity cost associated with following PJM dispatch instructions and reducing or suspending a unit's output due to a transmission constraint or other reliability issue, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of opportunity cost compensation, the Office of the Interconnection shall invoice the Market Seller accordingly. If the Market Monitoring Unit disagrees with the modified amount of opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(f-4) A Market Seller *of a* wind generating unit that is pool-scheduled or self-scheduled, has SCADA capability to transmit and receive instructions from the Office of the Interconnection, has provided data and established processes to follow PJM basepoints pursuant to the requirements for wind generating units as further detailed in this Agreement, the Tariff and the PJM Manuals, and which is operating as requested by the Office of the Interconnection, the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the , real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited *for each Real-time Settlement Interval* in an amount equal to the product of (A) the deviation of the generating unit's output necessary to follow the Office of the Interconnection's signals and the generating unit's expected output level if it had been dispatched in economic merit order, times (B) the Real-time Price at the generation bus for the generating unit, minus (C) the Total Lost Opportunity Cost Offer, provided that the resulting outcome is greater than $0.00. This equation is represented as (A*B) - C.

(g) The sum of the foregoing credits, plus any cancellation fees paid in accordance with Section 1.10.2(d), such cancellation fees to be applied to the Operating Day for which the unit was scheduled, plus any shortfalls paid pursuant to the Market Settlement provision of the real-time Economic Load Response Program, less any payments received from another Control Area for Operating Reserves shall be the cost of Operating Reserves for the Real-time Energy Market in each Operating Day.

(h) The cost of Operating Reserves for the Real-time Energy Market for each Operating Day, except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, shall be allocated and charged to each Market Participant *based on their daily total of hourly deviations determined in accordance with the following equation:*

$\sum_h (A + B + C)$

Where:

h = the hours in the applicable Operating Day;

A = For each Real-Time Settlement Interval in an hour, the sum of the absolute value of the withdrawal deviations (in MW) between the quantities scheduled in the Day-ahead Energy Market and the Market Participant's energy withdrawals (net of operating Behind The Meter Generation) in the Real-Time Energy Market, except as noted in subsection (h)(ii) below and in the PJM *Manuals divided by the number of Real-time Settlement Intervals for that hour. The summation of each Real-time Settlement Interval's withdrawal deviation in an hour will be the Market Participant's total hourly withdrawal deviations. Market Participant bilateral transactions that are Dynamic Transfers to load outside the PJM Region pursuant to section 1.12 of this Schedule are not included in the determination of withdrawal deviations*;

B = For each Real-Time Settlement Interval in an hour, the sum of the absolute value of generation deviations (*in MW and* not including deviations in Behind The Meter Generation) *as determined in subsection (o) divided by the number of Real-Time Settlement Intervals for that hour;*

C = For each Real-Time Settlement Interval in an hour, the sum of the absolute value of the injection deviations (in MW) between the quantities scheduled in the Day-ahead Energy Market and the Market Participant's energy injections in the Real-Time Energy Market divided by the number of Real-time Settlement Intervals for that hour. The summation of the injection deviations for each Real-time Settlement Interval in an hour will be the Market Participant's total hourly injection deviations. The determination of injection deviations does not include generation resources.

The Revenue Data for Settlements determined for each Real-time Settlement Interval in accordance with section 3.1A of this Schedule shall be used in determining the real-time *withdrawal deviations, generation deviations and injection deviations used to calculate Operating Reserve under this subsection (e).*

The costs associated with scheduling of units for Black Start service or testing of Black Start Units shall be allocated by ratio share of the monthly transmission use of each Network Customer or Transmission Customer serving Zone Load or Non-Zone Load, as determined in accordance with the formulas contained in Schedule 6A of the PJM Tariff.

Notwithstanding section (h)(1) above, as more fully set forth in the PJM Manuals, load deviations from the Day-ahead Energy Market shall not be assessed Operating Reserves charges to the extent attributable to reductions in the load of Price Responsive Demand that is in response to an increase in Locational Marginal Price from the Day-ahead Energy Market to the Real-time Energy Market and that is in accordance with a properly submitted PRD Curve.

Deviations that occur within a single Zone shall be associated with the Eastern or Western Region, as defined in Section 3.2.3(q) of this Schedule, and shall be subject to the regional balancing Operating Reserve rate determined in accordance with Section 3.2.3(q). Deviations at a hub shall be associated with the Eastern or Western Region if all the buses that define the hub are located in the region. Deviations at an Interface Pricing Point shall be associated with whichever region, the Eastern or Western Region, with which the majority of the buses that define that Interface Pricing Point are most closely electrically associated. If deviations at interfaces and hubs are associated with the Eastern or Western region, they shall be subject to the regional balancing Operating Reserve rate. Demand and supply deviations shall be based on total activity in a Zone, including all aggregates and hubs defined by buses that are wholly contained within the same Zone.

The foregoing notwithstanding, netting deviations shall be allowed *for each Real-time Settlement Interval* in accordance with the following provisions:

(i) Generation resources with multiple units located at a single bus shall be able to offset deviations in accordance with the PJM Manuals to determine the net deviation MW at the relevant bus.

(ii) Demand deviations will be assessed by comparing all day-ahead demand transactions at a single transmission zone, hub, or interface against the real-time demand transactions at that same transmission zone, hub, or interface; except that the positive values of demand deviations, as set forth in the PJM Manuals, will not be assessed Operating Reserve charges in the event of a Primary Reserve or Synchronized Reserve shortage in real-time or where PJM initiates the request for emergency load reductions in real-time in order to avoid a Primary Reserve or Synchronized Reserve shortage. The scheduled megawatt-hour withdrawal at the specified sink for an accepted Decrement Bid or Up-to Congestion Transaction are included in the determination of demand deviations. Bilateral transactions inside the PJM Region, as defined in section 1.7.10 of this Schedule, will not be included in the determination of demand deviations.

(iii) Supply deviations will be assessed by comparing all day-ahead transactions at a single transmission zone, hub, or interface against the real-time transactions at that same transmission zone, hub, or interface. The scheduled megawatt-hour injection at the specified source for an accepted Increment Offer or Up-to Congestion Transaction are included in the determination of supply deviations. Bilateral transactions inside the PJM Region, as defined in section 1.7.10 of this Schedule, will not be included in the determination of supply deviations.

(i) At the end of each Operating Day, Market Sellers shall be credited on the basis of their offered prices for synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, as well as the credits calculated as specified in Section 3.2.3(b) for those generators committed solely for the purpose of providing synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, at the request of the Office of the Interconnection.

(j) The sum of the foregoing credits as specified in Section 3.2.3(i) shall be the cost of Operating Reserves for synchronous condensing for the PJM Region for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-contingency operation for the Operating Day and shall be separately determined for the PJM Region.

(k) The cost of Operating Reserves for synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-contingency operation for each Operating Day shall be allocated and charged to each Market Participant in proportion to the sum of its (i) deliveries of energy to load (net of operating Behind The Meter Generation, but not to be less than zero) in the PJM Region, served under Network Transmission Service, in megawatt-hours during that Operating Day; and (ii) deliveries of energy sales from within the PJM Region to load outside such region in megawatt-hours during that Operating Day, but not including its bilateral transactions that are Dynamic Transfers to load outside the PJM Region pursuant to Section 1.12, as compared to the sum of all such deliveries for all Market Participants.

(l) For any Operating Day in either, as applicable, the Day-ahead Energy Market or the Real-time Energy Market for which, for all or any part of such Operating Day, the Office of the Interconnection: (i) declares a Maximum Generation Emergency; (ii) issues an alert that a Maximum Generation Emergency may be declared ("Maximum Generation Emergency Alert"); or (iii) schedules units based on the anticipation of a Maximum Generation Emergency or a Maximum Generation Emergency Alert, the Operating Reserves credit otherwise provided by Section 3.2.3.(b) or Section 3.2.3(e) in connection with market-based offers shall be limited as provided in subsections (n) or (m), respectively. The Office of the Interconnection shall provide timely notice on its internet site of the commencement and termination of any of the actions described in subsection (i), (ii), or (iii) of this subsection (l) (collectively referred to as "MaxGen Conditions"). Following the posting of notice of the commencement of a MaxGen Condition, a Market Seller may elect to submit a cost-based offer in accordance with Schedule 2 of the Operating Agreement, in which case subsections (m) and (n) shall not apply to such offer; provided, however, that such offer must be submitted in accordance with the deadlines in Section 1.10 for the submission of offers in the Day-ahead Energy Market or Real-time Energy Market, as applicable. Submission of a cost-based offer under such conditions shall not be precluded by Section 1.9.7(b); provided, however, that the Market Seller must return to compliance with

Section 1.9.7(b) when it submits its bid for the first Operating Day after termination of the MaxGen Condition.

(m) For the Real-time Energy Market, if the Effective Offer Price (as defined below) for a market-based offer is greater than $1,000/MWh and greater than the Market Seller's lowest available and applicable cost-based offer, the Market Seller shall not receive any credit for Operating Reserves. For purposes of this subsection (m), the Effective Offer Price shall be the amount that, absent subsections (l) and (m), would have been credited for Operating Reserves for such Operating Day pursuant to Section 3.2.3(e) plus the Real-time Energy Market revenues for the *Real-time Settlement Intervals* that the offer is economic divided by the megawatt hours of energy provided during the *Real-time Settlement Intervals* that the offer is economic. The *Real-time Settlement Intervals* that the offer is economic shall be: (i) the *Real-time Settlement Intervals* that the offer price for energy is less than or equal to the Real-time Price for the relevant generation bus, (ii) the *Real-time Settlement Intervals* in which the offer for energy is greater than Locational Marginal Price and the unit is operated at the direction of the Office of the Interconnection that are in addition to any *Real-time Settlement Intervals* required due to the minimum run time or other operating constraint of the unit, and (iii) for any unit with a minimum run time of one hour or less and with more than one start available per day, any hours the unit operated at the direction of the Office of the Interconnection.

(n) For the Day-ahead Energy Market, if notice of a MaxGen Condition is provided prior to 10:30 a.m. on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price for a market-based offer is greater than $1,000/MWh and greater than the Market Seller's lowest available and applicable cost-based offer, the Market Seller shall not receive any credit for Operating Reserves. If notice of a MaxGen Condition is provided after 10:30 a.m. on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than $1,000/MWh, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. If the Effective Offer Price is less than or equal to $1,000/MWh, regardless of when notice of a MaxGen Condition is provided, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. For purposes of this subsection (n), the Effective Offer Price shall be the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day divided by the megawatt hours of energy offered during the Specified Hours, plus the offer for energy during such hours. The Specified Hours shall be the lesser of: (1) the minimum run hours stated by the Market Seller in its Offer Data; and (2) either (i) for steam-electric generating units and for combined-cycle units when such units are operating in combined-cycle mode, the six consecutive hours of highest Day-ahead Price during such Operating Day when such units are running or (ii) for combustion turbine units and for combined-cycle units when such units are operating in combustion turbine mode, the two consecutive hours of highest Day-ahead Price during such Operating Day when such units are running. Notwithstanding any other provision in this subsection, the total compensation to a Market Seller on any Operating Day that includes a MaxGen Condition shall not exceed $1,000/MWh during the Specified Hours, where such total compensation in each such hour is defined as the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day pursuant to Section 3.2.3(b) divided by the

Specified Hours, plus the Day-ahead Price for such hour, and no Operating Reserves payments shall be made for any other hour of such Operating Day. If a unit operates in real time at the direction of the Office of the Interconnection consistently with its day-ahead clearing, then subsection (m) does not apply.

(o) Dispatchable pool-scheduled generation resources and dispatchable self-scheduled generation resources that follow dispatch shall not be assessed balancing Operating Reserve deviations. Pool-scheduled generation resources and dispatchable self-scheduled generation resources that do not follow dispatch shall be assessed balancing Operating Reserve deviations in accordance with the calculations described below and in the PJM Manuals.

The Office of the Interconnection shall calculate a ramp-limited desired MW value for generation resources where the economic minimum and economic maximum are at least as far apart in real-time as they are in day-ahead according to the following parameters:

(i) real-time economic minimum <= 105% of day-ahead economic minimum or day-ahead economic minimum plus 5 MW, whichever is greater.

(ii) real-time economic maximum >= 95% day-ahead economic maximum or day-ahead economic maximum minus 5 MW, whichever is lower.

The ramp-limited desired MW value for a generation resource shall be equal to:

$$\mathbf{Ramp\_Request_t} = {(\mathbf{UDStarget_{t-1}} - \mathbf{AOutput_{t-1}})}\Big/{(\mathbf{UDSLAtime_{t-1}})}$$

$$\mathbf{RL\_Desired_t} = \mathbf{AOutput_{t-1}} + \left(\mathbf{Ramp\_Request_t} * \mathbf{Case\_Eff\_time_{t-1}}\right)$$

where:

1. UDStarget = UDS basepoint for the previous UDS case
2. AOutput = Unit's output at case solution time
3. UDSLAtime = UDS look ahead time
4. Case_Eff_time = Time between base point changes
5. RL_Desired = Ramp-limited desired MW

To determine if a generation resource is following dispatch the Office of the Interconnection shall determine the unit's MW off dispatch and % off dispatch by using the lesser of the difference between the actual output and the UDS Basepoint or the actual output and ramp-limited desired MW value *for each Real-time Settlement Interval.* If the UDS Basepoint and the ramp-limited desired MW for the resource are unavailable, the Office of the Interconnection will determine the unit's MW off dispatch and % off dispatch by calculating the lesser of the difference between the actual output and the UDS LMP Desired *MW for each Real-time Settlement Interval*.

A pool-scheduled or dispatchable self-scheduled resource is considered to be following dispatch if its actual output is between its ramp-limited desired MW value and UDS Basepoint, or if its % off dispatch is <= 10, or its Real-time *Settlement Interval* MWh is within 5% of the *Real-time Settlement Interval* ramp-limited desired MW. A self-scheduled generator must also be dispatched above economic minimum. The degree of deviations for resources that are not following dispatch shall be determined *for each Real-time Settlement Interval* in accordance with the following provisions:

- A dispatchable self-scheduled resource that is not dispatched above economic minimum shall be assessed balancing Operating Reserve deviations according to the following formula: Real-time *Settlement Interval* MWh – Day-Ahead MWh.

- A resource that is dispatchable day-ahead but is Fixed Gen in real-time shall be assessed balancing Operating Reserve deviations according to the following formula: Real-time *Settlement Interval* MWh – UDS LMP Desired MW.

- Pool-scheduled generators that are not following dispatch shall be assessed balancing Operating Reserve deviations according to the following formula: Real-time *Settlement Interval* MWh –Ramp-Limited Desired MW.

- If a resource's real-time economic minimum is greater than its day-ahead economic minimum by 5% or 5 MW, whichever is greater, or its real-time economic maximum is less than its Day Ahead economic maximum by 5% or 5 MW, whichever is lower, and UDS LMP Desired MWh for the *Real-time Settlement Interval* is either below the real time economic minimum or above the real time economic maximum, then balancing Operating Reserve deviations for the resource shall be assessed according to the following formula: Real time *Settlement Interval* MWh – UDS LMP Desired MWh.

- If a resource is not following dispatch and its % Off Dispatch is <= 20%, balancing Operating Reserve deviations shall be assessed according to the following formula: Real-time *Settlement Interval* MWh – Ramp-Limited Desired MW. If deviation value is within 5% of Ramp-Limited Desired MW, balancing Operating Reserve deviations shall not be assessed.

- If a resource is not following dispatch and its % off Dispatch is > 20%, balancing Operating Reserve deviations shall be assessed according to the following formula: Real time *Settlement Interval* MWh – UDS LMP Desired MWh.

- If a resource is not following dispatch, and the resource has tripped, for the *Real-time Settlement Interval* the resource tripped and the *Real-time Settlement Intervals* it remains offline throughout its day-ahead schedule balancing Operating Reserve deviations shall be assessed according to the following formula: Real time *Settlement Interval* MWh – Day-Ahead MWh.

- For resources that are not dispatchable in both the Day-Ahead and Real-time Energy Markets balancing Operating Reserve deviations shall be assessed according to the following formula: Real-time *Settlement Interval* MWh - Day-Ahead MWh.

If a resource has a sum of the absolute value of generator deviations for an hour that is less than 5 MWh, then the resource shall not be assessed balancing Operating Reserve deviations for that hour.

(o-1) Dispatchable economic load reduction resources that follow dispatch shall not be assessed balancing Operating Reserve deviations. Economic load reduction resources that do not follow dispatch shall be assessed balancing Operating Reserve deviations as described in this subsection and as further specified in the PJM Manuals.

The Desired MW quantity for such resources for each hour shall be the hourly integrated MW quantity to which the load reduction resource was dispatched for each hour (where the hourly integrated value is the average of the dispatched values as determined by the Office of the Interconnection for the resource for each hour).

If the actual reduction quantity for the load reduction resource for a given hour deviates by no more than 20% above or below the Desired MW quantity, then no balancing Operating Reserve deviation will accrue for that hour. If the actual reduction quantity for the load reduction resource for a given hour is outside the 20% bandwidth, the balancing Operating Reserve deviations will accrue for that hour in the amount of the absolute value of (Desired MW – actual reduction quantity). For those hours where the actual reduction quantity is within the 20% bandwidth specified above, the load reduction resource will be eligible to be made whole for the total value of its offer as defined in section 3.3A of this Appendix. Hours for which the actual reduction quantity is outside the 20% bandwidth will not be eligible for the make-whole payment. If at least one hour is not eligible for make-whole payment based on the 20% criteria, then the resource will also not be made whole for its shutdown cost.

(p) The Office of the Interconnection shall allocate the charges assessed pursuant to Section 3.2.3(h) of Schedule 1 of this Agreement except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, to real-time deviations from day-ahead schedules or real-time load share plus exports depending on whether the underlying balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

(i) For resources scheduled by the Office of the Interconnection during the reliability analysis for an Operating Day, the associated balancing Operating Reserve charges shall be allocated based on the reason the resource was scheduled according to the following provisions:

(A) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to operate in real-time to augment the physical resources committed in the Day-ahead

Energy Market to meet the forecasted real-time load plus the Operating Reserve requirement, the associated balancing Operating Reserve charges shall be allocated to real-time deviations from day-ahead schedules.

(B) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to maintain system reliability, the associated balancing Operating Reserve charges shall be allocated according to ratio share of real time load plus export transactions.

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing Operating Reserves, the associated balancing Operating Reserve charges shall be allocated pursuant to (A) or (B) above.

(ii) For resources scheduled during an Operating Day, the associated balancing Operating Reserve charges shall be allocated according to the following provisions:

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Operating Reserve charges shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, charges will be assessed pursuant to this section only if the LMP at the resource's bus does not meet or exceed the applicable offer of the resource for at least four-5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the charges for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category as identified for the Operating Reserves for the other discrete clock hours.

(B) If the Office of the Interconnection directs a resource not covered by Section 3.2.3(h)(ii)(A) of Schedule 1 of this Agreement to operate in real-time during an Operating Day, the associated balancing Operating Reserve charges shall be allocated according to real-time deviations from day-ahead schedules.

(q) The Office of the Interconnection shall determine regional balancing Operating Reserve rates for the Western and Eastern Regions of the PJM Region. For the purposes of this section, the Western Region shall be the AEP, APS, ComEd, Duquesne, Dayton, ATSI, DEOK, EKPC transmission Zones, and the Eastern Region shall be the AEC, BGE, Dominion, PENELEC, PEPCO, ME, PPL, JCPL, PECO, DPL, PSEG, RE transmission Zones. The regional balancing Operating Reserve rates shall be determined in accordance with the following provisions:

(i) The Office of the Interconnection shall calculate regional adder rates for the Eastern and Western Regions. Regional adder rates shall be equal to the total balancing Operating Reserve credits paid to generators for transmission constraints that occur on transmission system capacity equal to or less than 345kv. The regional adder rates shall be separated into reliability and deviation charges, which shall be allocated to real-time load or real-time deviations, respectively. Whether the underlying credits are designated as reliability or deviation charges shall be determined in accordance with Section 3.2.3(p).

(ii) The Office of the Interconnection shall calculate RTO balancing Operating Reserve rates. RTO balancing Operating Reserve rates shall be equal to balancing Operating Reserve credits except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, in excess of the regional adder rates calculated pursuant to Section 3.2.3(q)(i) of Schedule 1 of this Agreement. The RTO balancing Operating Reserve rates shall be separated into reliability and deviation charges, which shall be allocated to real-time load or real-time deviations, respectively. Whether the underlying credits are allocated as reliability or deviation charges shall be determined in accordance with Section 3.2.3(p).

(iii) Reliability and deviation regional balancing Operating Reserve rates shall be determined by summing the relevant RTO balancing Operating Reserve rates and regional adder rates.

(iv) If the Eastern and/or Western Regions do not have regional adder rates, the relevant regional balancing Operating Reserve rate shall be the reliability and/or deviation RTO balancing Operating Reserve rate.

(r) Market Sellers that incur incremental operating costs for a generation resource *that are either* greater than $*1*,000/MWh *as* determined in accordance with *the Market Seller's PJM-approved Fuel Cost Policy,* Schedule 2 of the Operating Agreement and PJM Manual 15, *but are not verified at the time of dispatch of the resource under section 6.4.3 of this Schedule, or greater than $2,000/MWh as determined in accordance with the Market Seller's PJM-approved Fuel Cost Policy, Schedule 2 of the Operating Agreement, and PJM Manual 15,* will be eligible to receive credit for Operating Reserves upon review of the Market Monitoring Unit and the Office of the Interconnection, and approval of the Office of the Interconnection. Market Sellers must submit to the Office of the Interconnection and the Market Monitoring Unit all relevant documentation demonstrating the calculation of costs greater than *$2,000/MWh, and costs greater than* $*1*,000/MWh *which were not verified at the time of dispatch of the resource under section 6.4.3 of this Schedule*. The Office of the Interconnection must approve any Operating Reserve credits paid to a Market Seller under this subsection (r).

3.2.3A Synchronized Reserve.

(a) Each Market Participant that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Synchronized Reserve equal to its pro rata share of Synchronized Reserve requirements for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market *Participant's* total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone or Reserve Sub-zone for the hour ("Synchronized Reserve Obligation"), less any amount obtained from condensers associated with provision of Reactive Services as described in section 3.2.3B(i) and any amount obtained from condensers associated with post-contingency operations, as described in section 3.2.3C(b). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. A Market Participant *with an* hourly Synchronized Reserve Obligation shall be charged *the pro rata share of the sum of the quantity of Synchronized Reserves provided in each Real-time Settlement Interval times the clearing price for all Real-time Settlement Intervals in the hour associated with that obligation.*

(b) A resource supplying Synchronized Reserve at the direction of the Office of the Interconnection, in excess of its hourly Synchronized Reserve Obligation, shall be credited as follows:

> i) Credits for Synchronized Reserve provided by generation resources that are then subject to the energy dispatch signals and instructions of the Office of the Interconnection and that increase their current output or Demand Resources that reduce their load in response to a Synchronized Reserve Event ("Tier 1 Synchronized Reserve") shall be at the Synchronized Energy Premium Price*, as described in 3.2.3A (c),* with the exception of those *Real-time Settlement Intervals* in which the Non-Synchronized Reserve Market Clearing Price for the applicable Reserve Zone or Reserve Sub-zone is not equal to zero. During such hours, Tier 1 Synchronized Reserve resources shall be compensated at the Synchronized Reserve Market Clearing Price for the applicable Reserve Zone or Reserve Sub-zone for the lesser of the amount of Tier 1 Synchronized Reserve attributed to the resource as calculated by the Office of the Interconnection, or the actual amount of Tier 1 Synchronized Reserve provided should a Synchronized Reserve Event *occur in a Real-time Settlement Interval*.
>
> ii) Credits for Synchronized Reserve provided by generation resources that are synchronized to the grid but, at the direction of the Office of the Interconnection, are operating at a point that deviates from the Office of the Interconnection energy dispatch signals and instructions ("Tier 2 Synchronized Reserve") shall be the higher of (i) the Synchronized Reserve Market Clearing Price or (ii) the sum of (A) the Synchronized Reserve offer, and (B) the specific opportunity cost of the generation resource supplying the increment of Synchronized Reserve, as determined by the Office of the Interconnection *to a Synchronized Reserve Event in a Real-time Settlement Interval* in accordance with procedures specified in the PJM Manuals.
>
> iii) Credits for Synchronized Reserve provided by Demand Resources that are synchronized to the grid and accept the obligation to reduce load in response to a Synchronized Reserve Event *in a Real-time Settlement Interval* initiated by the Office of

the Interconnection shall be the sum of (i) the higher of (A) the Synchronized Reserve offer or (B) the Synchronized Reserve Market Clearing Price and (ii) if a Synchronized Reserve Event is actually initiated by the Office of the Interconnection and the Demand Resource reduced its load in response to the event, the fixed costs associated with achieving the load reduction, as specified in the PJM Manuals.

(c) The Synchronized Reserve Energy Premium Price is an adder in an amount to be determined periodically by the Office of the Interconnection not less than fifty dollars and not to exceed one hundred dollars per megawatt hour.

(d) The Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each *Real-time Settlement Interval* of the Operating Day. The hourly Synchronized Reserve Market Clearing Price shall be calculated as the 5-minute clearing price. Each 5-minute clearing price shall be calculated as the marginal cost of serving the next increment of demand for Synchronized Reserve in each Reserve Zone or Reserve Sub-zone, inclusive of Synchronized Reserve offer prices and opportunity costs. When the Synchronized Reserve Requirement or Extended Synchronized Reserve Requirement in a Reserve Zone or Reserve Sub-zone cannot be met, the 5-minute clearing price shall be at least greater than or equal to the applicable Reserve Penalty Factor for the Reserve Zone or Reserve Sub-zone, but less than or equal to the sum of the Reserve Penalty Factors for the Synchronized Reserve Requirement and Primary Reserve Requirement for the Reserve Zone or Reserve Sub-zone. If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a Voltage Reduction Action as described in the PJM Manuals or a Manual Load Dump Action as described in the PJM Manuals, the 5-minute clearing price shall be the sum of the Reserve Penalty Factors for the Primary Reserve Requirement and the Synchronized Reserve Requirement for that Reserve Zone or Reserve Sub-zone.

The Reserve Penalty Factor for the Synchronized Reserve Requirement shall be $850/MWh.

The Reserve Penalty Factor for the Extended Synchronized Reserve Requirement shall be $300/MWh.

By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to prices exceeding $1,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Synchronized Reserve Penalty Factors are warranted for subsequent Delivery Year(s).

(e) *For each Real-time Settlement Interval and for* determining the 5-minute Synchronized Reserve clearing price, the estimated unit-specific opportunity cost for a generation resource *will be determined in accordance with the following equation:*

(A x B) + (C x D)

Where

A = *T*he Locational Marginal Price at the generation bus for the generation resource*;*

B = *T*he megawatts of energy used to provide Synchronized Reserve submitted as part of the Synchronized Reserve offer*;*

*C = T*he deviation of the set point of the generation resource that is expected to be required in order to provide Synchronized Reserve from the generation resource's expected output level if it had been dispatched in economic merit order*; and*

*D = T*he difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource.

The opportunity costs for a Demand Resource shall be zero.

(f) In determining the credit under subsection (b) to a resource selected to provide Tier 2 Synchronized Reserve and that actively follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each *Real-time Settlement Interval* that the Office of the Interconnection requires a generation resource to provide Tier 2 Synchronized Reserve and shall be *in accordance with the following equation:*

(A x B) + (C x D)

Where:

A *= T*he megawatts of energy used by the resource to provide Synchronized Reserve as submitted as part of the generation resource's Synchronized Reserve offer;

B *= T*he Locational Marginal Price at the generation bus of the generation resource;

*C = T*he deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order*; and*

D = *T*he difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the generation resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource.

The opportunity costs for a Demand Resource shall be zero.

(g) Charges for Tier 1 Synchronized Reserve will be allocated in proportion to the amount of Tier 1 Synchronized Reserve applied to each Synchronized Reserve Obligation. In the event Tier 1 Synchronized Reserve is provided by a Market *Participant* in excess of that Market *Participant's* Synchronized Reserve Obligation, the Tier 1 Synchronized Reserve that is not utilized to fulfill the *Market Participant's* obligation will be allocated proportionately among all other Synchronized Reserve Obligations.

(h) Any amounts credited for Tier 2 Synchronized Reserve in a *Real-time Settlement Interval* in excess of the Synchronized Reserve Market Clearing Price in that *Real-time Settlement Interval* shall be allocated and charged to each Market Participant that does not meet its hourly Synchronized Reserve Obligation in proportion to its purchases of Synchronized Reserve in megawatt-hours during that hour.

(i) In the event the Office of the Interconnection needs to assign more Tier 2 Synchronized Reserve during a *Real-time Settlement Interval* than was estimated as needed at the time the Synchronized Reserve Market Clearing Price was calculated for that *Real-time Settlement Interval* due to a reduction in available Tier 1 Synchronized Reserve, the costs of the excess Tier 2 Synchronized Reserve shall be allocated and charged to those providers of Tier 1 Synchronized Reserve whose available Tier 1 Synchronized Reserve was reduced from the needed amount estimated during the Synchronized Reserve Market Clearing Price calculation, in proportion to the amount of the reduction in Tier 1 Synchronized Reserve availability.

(j) In the event a generation resource or Demand Resource that either has been assigned by the Office of the Interconnection or self-scheduled to provide Tier 2 Synchronized Reserve fails to provide the assigned or self-scheduled amount of Tier 2 Synchronized Reserve in response to a Synchronized Reserve Event, the resource will be credited for Tier 2 Synchronized Reserve capacity in the amount that actually responded for all *Real-time Settlement Intervals* the resource was assigned or self-scheduled Tier 2 Synchronized Reserve on the Operating Day during which the event occurred. The determination of the amount of Synchronized Reserve credited to a resource shall be on an individual resource basis, not on an aggregate basis.

The resource shall refund payments received for Tier 2 Synchronized Reserve it failed to provide. For purposes of determining the amount of the payments to be refunded by a Market Participant, the Office of the Interconnection shall calculate the shortfall of Tier 2 Synchronized Reserve on an individual resource basis unless the Market Participant had multiple resources that were assigned or self-scheduled to provide Tier 2 Synchronized Reserve, in which case the shortfall will be determined on an aggregate basis. For performance determined on an aggregate basis, the response of any resource that provided more Tier 2 Synchronized Reserve than it was assigned or self-scheduled to provide will be used to offset the performance of other resources that provided less Tier 2 Synchronized Reserve than they were assigned or self-scheduled to provide during a Synchronized Reserve Event, as calculated in the PJM Manuals. The determination of a Market Participant's aggregate response shall not be taken into consideration in the determination of the amount of Tier 2 Synchronized Reserve credited to each individual resource.

The amount refunded shall be determined by multiplying the Synchronized Reserve Market Clearing Price by the amount of the shortfall of Tier 2 Synchronized Reserve, measured in megawatts, for all *intervals* the resource was assigned or self-scheduled to provide Tier 2 Synchronized Reserve for a period of time immediately preceding the Synchronized Reserve Event equal to the lesser of the average number of days between Synchronized Reserve Events, or the number of days since the resource last failed to provide the amount of Tier 2 Synchronized Reserve it was assigned or self-scheduled to provide in response to a Synchronized Reserve Event. The average number of days between Synchronized Reserve Events for purposes of this calculation shall be determined by an annual review of the twenty-four month period ending October 31 of the calendar year in which the review is performed, and shall be rounded down to a whole day value. The Office of the Interconnection shall report the results of its annual review to stakeholders by no later than December 31, and the average number of days between Synchronized Reserve Events shall be effective as of the following January 1. The refunded charges shall be allocated as credits to Market Participants based on its pro rata share of the Synchronized Reserve Obligation megawatts less any Tier 1 Synchronized Reserve applied to its Synchronized Reserve Obligation in the hour(s) of the Synchronized Reserve Event for the Reserve Sub-zone or Reserve Zone, except that Market Participants that incur a refund obligation and also have an applicable Synchronized Reserve Obligation during the hour(s) of the Synchronized Reserve Event shall not be included in the allocation of such refund credits. If the event spans multiple hours, the refund credits will be prorated hourly based on the duration of the event within each clock hour.

(k) The magnitude of response to a Synchronized Reserve Event by a generation resource or a Demand Resource, except for Batch Load Demand Resources covered by section 3.2.3A(l), is the difference between the generation resource's output or the Demand Resource's consumption at the start of the event and its output or consumption 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output or Demand Resource consumption at the start of the event is defined as the lowest telemetered generator resource output or greatest Demand Resource consumption between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output or a Demand Resource's consumption 10 minutes after the event is defined as the greatest generator resource output or lowest Demand Resource consumption achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter. The response actually credited to a Demand Resource will be reduced by the amount the megawatt consumption of the Demand Resource exceeds the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

(l) The magnitude of response by a Batch Load Demand Resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the start of a Synchronized Reserve Event shall be the difference between (i) the Batch Load Demand Resource's consumption at the end of the Synchronized Reserve Event and (ii) the Batch Load Demand Resource's consumption during the minute within the ten minutes after the end of the Synchronized Reserve Event in which the Batch Load Demand Resource's consumption was highest and for which its consumption in all subsequent minutes within the ten minutes was not less than fifty percent of the consumption in such minute; provided that, the

magnitude of the response shall be zero if, when the Synchronized Reserve Event commences, the scheduled off-cycle stage of the production cycle is greater than ten minutes. .

3.2.3A.001 Non-Synchronized Reserve.

(a) Each Market Participant that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Non-Synchronized Reserve equal to its pro rata share of Non-Synchronized Reserve assigned for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market *Participant's* total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone and Reserve Sub-zone for the hour ("Non-Synchronized Reserve Obligation"). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. A Market Participant *with an* hourly Non-Synchronized Reserve Obligation shall be charged *the pro rata share of the sum of the quantity of Non-Synchronized Reserves provided in each Real-time Settlement Interval times the clearing price for all Real-time Settlement Intervals in the hour associated with that obligation.*

(b) Credits for Non-Synchronized Reserve provided by generation resources that are not operating for energy at the direction of the Office of the Interconnection specifically for the purpose of providing Non-Synchronized Reserve shall be the higher of (i) the Non-Synchronized Reserve Market Clearing Price or (ii) the specific opportunity cost of the generation resource supplying the increment of Non-Synchronized Reserve, as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

(c) The Non-Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each *Real-time Settlement Interval* of the Operating Day. The Non-Synchronized Reserve Market Clearing Price shall be calculated as the 5-minute clearing price. Each 5-minute clearing price shall be calculated as the marginal cost of procuring sufficient Non-Synchronized Reserves and/or Synchronized Reserves in each Reserve Zone or Reserve Sub-zone inclusive of opportunity costs associated with meeting the Primary Reserve Requirement or Extended Primary Reserve Requirement. When the Primary Reserve Requirement or Extended Primary Reserve Requirement in a Reserve Zone or Reserve Sub-zone cannot be met at a price less than or equal to the applicable Reserve Penalty Factor, the 5-minute clearing price for Non-Synchronized Reserve shall be at least greater than or equal to the applicable Reserve Penalty Factor for the Reserve Zone or Reserve Sub-zone, but less than or equal to the Reserve Penalty Factor for the Primary Reserve Requirement for the Reserve Zone or Reserve Sub-zone. If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a *V*oltage *R*eduction *A*ction as described in the PJM Manuals or a *M*anual *L*oad *D*ump *A*ction as described in the PJM Manuals, the 5-minute clearing price shall be the Reserve Penalty Factor for the Primary Reserve Requirement for that Reserve Zone or Reserve Sub-zone.

The Reserve Penalty Factor for the Synchronized Reserve Requirement shall be $850/MWh.

The Reserve Penalty Factor for the Extended Primary Reserve Requirement shall be $300/MWh.

By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to prices exceeding $1,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Primary Reserve Penalty Factors are warranted for subsequent Delivery Year(s).

(d) *For each Real-time Settlement Interval and for* determining the 5-minute Non-Synchronized Reserve clearing price, the unit-specific opportunity cost for a generation resource that is not providing energy because they are providing Non-Synchronized Reserves *will be determined in accordance with the following equation:*

(A x B) – C

Where:

A = *T*he deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order;

B = *T*he Locational Marginal Price at the generation bus for the generation resource; *and*

C = *T*he applicable offer for energy from the generation resource in the PJM Interchange Energy Market.

(e) In determining the credit under subsection (b) to a resource selected to provide Non-Synchronized Reserve and that follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each *Real-time Settlement Interval* that the Office of the Interconnection requires a generation resource to provide Non- Synchronized Reserve and shall be *in accordance with the following equation:*

(A x B) – C

Where:

A = *T*he deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order;

B = *T*he Locational Marginal Price at the generation bus for the generation resource; *and*

C = *T*he applicable offer for energy from the generation resource in the PJM Interchange Energy Market.

(f) Any amounts credited for Non-Synchronized Reserve in a *Real-time Settlement Interval* in excess of the Non-Synchronized Reserve Market Clearing Price in that *Real-time Settlement Interval* shall be allocated and charged to each Market Participant that does not meet its hourly Non-Synchronized Reserve Obligation in proportion to its purchases of Non-Synchronized Reserve in megawatt-hours during that hour.

(g) The magnitude of response to a Non-Synchronized Reserve Event by a generation resource is the difference between the generation resource's output at the start of the event and its output 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output at the start of the event is defined as the lowest telemetered generator resource output between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output 10 minutes after the start of the event is defined as the greatest generator resource output achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

(h) In the event a generation resource that has been assigned by the Office of the Interconnection to provide Non-Synchronized Reserve fails to provide the assigned amount of Non-Synchronized Reserve in response to a Non-Synchronized Reserve Event, the resource will be credited for Non-Synchronized Reserve capacity in the amount that actually responded for the contiguous *Real-time Settlement Interval* the resource was assigned Non-Synchronized Reserve during which the event occurred.

3.2.3A.01 Day-ahead Scheduling Reserves.

(a) The Office of the Interconnection shall satisfy the Day-ahead Scheduling Reserves Requirement by procuring Day-ahead Scheduling Reserves in the Day-ahead Scheduling Reserves Market from Day-ahead Scheduling Reserves Resources, provided that Demand Resources shall be limited to providing the lesser of any limit established by the Reliability First Corporation or SERC, as applicable, or twenty-five percent of the total Day-ahead Scheduling Reserves Requirement. Day-ahead Scheduling Reserves Resources that clear in the Day-ahead Scheduling Reserves Market shall receive a Day-ahead Scheduling Reserves schedule from the Office of the Interconnection for the relevant Operating Day. PJMSettlement shall be the Counterparty to the purchases and sales of Day-ahead Scheduling Reserves in the PJM Interchange Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a self-schedule or self-supply of generation resources by a Market Buyer to satisfy its Day-ahead Scheduling Reserves Requirement.

(b) A Day-ahead Scheduling Reserves Resource that receives a Day-ahead Scheduling Reserves schedule pursuant to subsection (a) of this section shall be paid the hourly Day-ahead Scheduling Reserves Market clearing price for the cleared megawatt quantity of Day-ahead Scheduling Reserves in each hour of the schedule, subject to meeting the requirements of subsection (c) of this section.

(c) To be eligible for payment pursuant to subsection (b) of this section, Day-ahead Scheduling Reserves Resources shall comply with the following provisions:

(i) Generation resources with a start time greater than thirty minutes are required to be synchronized and operating at the direction of the Office of the Interconnection during the resource's Day-ahead Scheduling Reserves schedule and shall have a dispatchable range equal to or greater than the Day-ahead Scheduling Reserves schedule.

(ii) Generation resources and Demand Resources with start times or shut-down times, respectively, equal to or less than 30 minutes are required to respond to dispatch directives from the Office of the Interconnection during the resource's Day-ahead Scheduling Reserves schedule. To meet this requirement the resource shall be required to start or shut down within the specified notification time plus its start or shut down time, provided that such time shall be less than thirty minutes.

(iii) Demand Resources with a Day-ahead Scheduling Reserves schedule shall be credited based on the difference between the resource's MW consumption at the time the resource is directed by the Office of the Interconnection to reduce its load (starting MW usage) and the resource's MW consumption at the time when the Demand Resource is no longer dispatched by PJM (ending MW usage). For the purposes of this subsection, a resource's starting MW usage shall be the greatest telemetered consumption between one minute prior to and one minute following the issuance of a dispatch instruction from the Office of the Interconnection, and a resource's ending MW usage shall be the lowest consumption between one minute before and one minute after a dispatch instruction from the Office of the Interconnection that is no longer necessary to reduce.

(iv) Notwithstanding subsection (iii) above, the credit for a Batch Load Demand Resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the time the resource is directed by the Office of the Interconnection to reduce its load shall be the difference between (i) the "ending MW usage" (as defined above) and (ii) the Batch Load Demand Resource's consumption during the minute within the ten minutes after the time of the "ending MW usage" in which the Batch Load Demand Resource's consumption was highest and for which its consumption in all subsequent minutes within the ten minutes was not less than fifty percent of the consumption in such minute; provided that, the credit shall be zero if, at the time the resource is directed by the Office of the Interconnection to reduce its load, the scheduled off-cycle stage of the production cycle is greater than the timeframe for which the resource was dispatched by PJM.

Resources that do not comply with the provisions of this subsection (c) shall not be eligible to receive credits pursuant to subsection (b) of this section.

(d) The hourly credits paid to Day-ahead Scheduling Reserves Resources satisfying the Base Day-ahead Scheduling Reserves Requirement ("Base Day-ahead Scheduling Reserves credits") shall equal the ratio of the Base Day-ahead Scheduling Reserves Requirement to the Day-ahead Scheduling Reserves Requirement, multiplied by the total credits paid to Day-ahead Scheduling Reserves Resources, and are allocated as Base Day-ahead Scheduling Reserves charges per paragraph (i) below. The hourly credits paid to Day-ahead Scheduling Reserve Resources satisfying the Additional Day-ahead Scheduling Reserve Requirement ("Additional Day-ahead Scheduling Reserves credits") shall equal the ratio of the Additional Day-ahead Scheduling Reserves Requirement to the Day-ahead Scheduling Reserves Requirement, multiplied by the total credits paid to Day-ahead Scheduling Reserves Resources and are allocated as Additional Day-ahead Scheduling Reserves charges per paragraph (ii) below.

(i) A Market Participant's Base Day-ahead Scheduling Reserves charge is equal to the ratio of the Market Participant's hourly obligation to the total hourly obligation of all Market Participants in the PJM Region, multiplied by the Base Day-ahead Scheduling Reserves credits. The hourly obligation for each Market Participant is a megawatt representation of the portion of the Base Day-ahead Scheduling Reserves credits that the Market Participant is responsible for paying to PJM. The hourly obligation is equal to the Market Participant's load ratio share of the total megawatt volume of Base Day-ahead Scheduling Reserves resources (described below), based on the Market Participant's total hourly load (net of operating Behind The Meter Generation, but not to be less than zero) to the total hourly load of all Market Participants in the PJM Region. The total megawatt volume of Base Day-ahead Scheduling Reserves resources equals the ratio of the Base Day-ahead Scheduling Reserves Requirement to the Day-ahead Scheduling Reserves Requirement multiplied by the total volume of Day-ahead Scheduling Reserves megawatts paid pursuant to paragraph (c) of this section. A Market Participant's hourly Day-ahead Scheduling Reserves obligation can be further adjusted by any Day-ahead Scheduling Reserve bilateral transactions.

(ii) Additional Day-ahead Scheduling Reserves credits shall be charged hourly to Market Participants that are net purchasers in the Day-ahead Energy Market based on its positive demand difference ratio share. The positive demand difference for each Market Participant is the difference between its real-time load (net of operating Behind The Meter Generation, but not to be less than zero) and cleared Demand Bids in the Day-ahead Energy Market, net of cleared Increment Offers and cleared Decrement Bids in the Day-ahead Energy Market, when such value is positive. Net purchasers in the Day-ahead Energy Market are those Market Participants that have cleared Demand Bids plus cleared Decrement Bids in excess of its amount of cleared Increment Offers in the Day-ahead Energy Market. If there are no Market Participants with a positive demand difference, the Additional Day-ahead Scheduling Reserves credits are allocated according to paragraph (i) above.

(e) If the Day-ahead Scheduling Reserves Requirement is not satisfied through the operation of subsection (a) of this section, any additional Operating Reserves required to meet the requirement shall be scheduled by the Office of the Interconnection pursuant to Section 3.2.3 of Schedule 1 of this Agreement.

3.2.3B Reactive Services.

(a) A Market Seller providing Reactive Services at the direction of the Office of the Interconnection shall be credited as specified below for the operation of its resource. These provisions are intended to provide payments to generating units when the LMP dispatch algorithms would not result in the dispatch needed for the required reactive service. LMP will be used to compensate generators that are subject to redispatch for reactive transfer limits.

(b) At the end of each Operating Day, where the active energy output of a Market Seller's resource is reduced or suspended at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region, the Market Seller shall be credited according to Sections 3.2.3B(c) & 3.2.3B(d).

(c) A Market Seller providing Reactive Services from either a steam-electric generating unit or combined cycle unit operating in combined cycle mode, where such unit is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override) shall be compensated for lost opportunity cost by receiving a credit in an amount equal to the product of (A) the deviation of the generating unit's output necessary to follow the Office of the Interconnection's signals and the generating unit's expected output level if it had been dispatched in economic merit order, times (B) the Real-time Price at the generation bus for the generating unit, minus (C) the Total Lost Opportunity Cost Offer, provided that the resulting outcome is greater than $0.00. This equation is represented as (A*B) - C.

(d) A Market Seller providing Reactive Services from either a combustion turbine unit or combined cycle unit operating in simple cycle mode that is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost, limited to the lesser of the unit's Economic Maximum or the unit's Generation Resource Maximum Output, if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection as directed by the PJM dispatcher, then the Market Seller shall be credited in a manner consistent with that described above in Section 3.2.3B(c) for a steam unit or a combined cycle unit operating in combined cycle mode.

(e) At the end of each Operating Day, where the active energy output of a Market Seller's unit is increased at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region and the offered price of the energy is above the real-time LMP at the unit's bus, the Market Seller shall be credited according to Section 3.2.3B(f).

(f) A Market Seller providing Reactive Services from either a steam-electric generating unit, combined cycle unit or combustion turbine unit, where such unit is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the real time LMP at the unit's bus is lower than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall receive a credit hourly in an amount equal to {(AG - LMPDMW) x (UB - URTLMP)}where:

AG equals the actual output of the unit;

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the real time LMP at the unit's bus and adjusted for any Regulation or Tier 2 Synchronized Reserve assignments;

UB equals the unit offer for that unit for which output is increased, determined according to the lesser of the Final Offer or Committed Offer;

URTLMP equals the real time LMP at the unit's bus; and

where UB - URTLMP shall not be negative.

(g) A Market Seller providing Reactive Services from a hydroelectric resource where such resource is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the output of such resource is altered from the schedule submitted by the Market Seller for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(h) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for lost opportunity cost associated with following the Office of the Interconnection's dispatch instructions to reduce or suspend a unit's output for the purpose of maintaining reactive reliability, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of such alternate lost opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of alternate lost opportunity cost compensation, the Office of the Interconnection shall invoice the Market *Participant* accordingly. If the Market Monitoring Unit disagrees with the modified amount of alternate lost opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(i) The amount of Synchronized Reserve provided by generating units maintaining reactive reliability shall be counted as Synchronized Reserve satisfying the overall PJM Synchronized Reserve requirements. Operators of these generating units shall be notified of such provision, and to the extent a generating unit's operator indicates that the generating unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in Section 3.2.3A regarding provision of Tier 2 Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated to provide Reactive Services also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the Synchronized Reserve Market Clearing Price for each *Real-time Settlement Interval* a generating unit provided synchronous condensing multiplied by the amount of Synchronized reserve provided by the synchronous condenser or (ii) the sum of (A) the generating unit's cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the product of MW energy usage for providing synchronous condensing multiplied by the real time LMP at the generating unit's bus, (C) the generating unit's startup-cost of providing synchronous condensing, and (D) the unit-specific lost opportunity cost of the generating resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated to provide Reactive Services was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generating unit's cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to subsection (l) below.

(j) A Market Seller's pool scheduled steam-electric generating unit or combined cycle unit operating in combined cycle mode, that is not committed to operate in the Day-ahead Market, but that is directed by the Office of the Interconnection to operate solely for the purpose of maintaining reactive reliability, at the request of the Office of the Interconnection, shall be credited in the amount of the unit's offered price for start-up and no-load fees. The unit also shall receive, if applicable, compensation in accordance with Sections 3.2.3B(e)-(f).

(k) The sum of the foregoing credits as specified in Sections 3.2.3B(b)-(j) shall be the cost of Reactive Services for the purpose of maintaining reactive reliability for the Operating Day and shall be separately determined for each transmission zone in the PJM Region based on whether the resource was dispatched for the purpose of maintaining reactive reliability in such transmission zone.

(l) The cost of Reactive Services for the purpose of maintaining reactive reliability in a transmission zone in the PJM Region for each Operating Day shall be allocated and charged to each Market Participant in proportion to its deliveries of energy to load (net of operating Behind The Meter Generation) in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

(m) Generating units receiving dispatch instructions from the Office of the Interconnection under the expectation of increased actual or reserve reactive shall inform the Office of the Interconnection dispatcher if the requested reactive capability is not achievable.

Should the operator of a unit receiving such instructions realize at any time during which said instruction is effective that the unit is not, or likely would not be able to, provide the requested amount of reactive support, the operator shall as soon as practicable inform the Office of the Interconnection dispatcher of the unit's inability, or expected inability, to provide the required reactive support, so that the associated dispatch instruction may be cancelled. PJM Performance Compliance personnel will audit operations after-the-fact to determine whether a unit that has altered its active power output at the request of the Office of the Interconnection has provided the actual reactive support or the reactive reserve capability requested by the Office of the Interconnection. PJM shall utilize data including, but not limited to, historical reactive performance and stated reactive capability curves in order to make this determination, and may withhold such compensation as described above if reactive support as requested by the Office of the Interconnection was not or could not have been provided.

3.2.3C Synchronous Condensing for Post-Contingency Operation.

(a) Under normal circumstances, PJM operates generation out of merit order to control contingency overloads when the flow on the monitored element for loss of the contingent element ("contingency flow") exceeds the long-term emergency rating for that facility, typically a 4-hour or 2-hour rating. At times however, and under certain, specific system conditions, PJM does not operate generation out of merit order for certain contingency overloads until the contingency flow on the monitored element exceeds the 30-minute rating for that facility ("post-contingency operation"). In conjunction with such operation, when the contingency flow on such element exceeds the long-term emergency rating, PJM operates synchronous condensers in the areas affected by such constraints, to the extent they are available, to provide greater certainty that such resources will be capable of producing energy in sufficient time to reduce the flow on the monitored element below the normal rating should such contingency occur.

(b) The amount of Synchronized Reserve provided by synchronous condensers associated with post-contingency operation shall be counted as Synchronized Reserve satisfying the PJM Synchronized Reserve requirements. Operators of these generation units shall be notified of such provision, and to the extent a generation unit's operator indicates that the generation unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in Section 3.2.3A regarding provision of Tier 2 Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated in conjunction with post-contingency operation also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing in conjunction with post-contingency operation at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the Synchronized Reserve Market Clearing Price for each *applicable interval* a generation resource provided synchronous condensing multiplied by the amount of Synchronized Reserve provided by the synchronous condenser or (ii) the sum of (A) the generation resource's *applicable interval* cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the *applicable interval* product of the megawatts of energy used to provide synchronous condensing multiplied by the real-time LMP at the generation bus of the generation resource, (C) the generation resource's start-up cost of providing synchronous condensing, and (D) the unit-specific lost opportunity cost of the generation resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated in association with post-contingency constraint control was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generation unit's cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to subsection (d) below.

(c) The sum of the foregoing credits as specified in section 3.2.3C(b) shall be the cost of synchronous condensers associated with post-contingency operations for the Operating Day and shall be separately determined for each transmission zone in the PJM Region based on whether the resource was dispatched in association with post-contingency operation in such transmission zone.

(d) The cost of synchronous condensers associated with post-contingency operations in a transmission zone in the PJM Region for each Operating Day shall be allocated and charged to each Market Participant in proportion to its deliveries of energy to load (net of operating Behind The Meter Generation) in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

3.2.4 Transmission Congestion Charges.

Each Market Buyer shall be assessed Transmission Congestion Charges as specified in Section 5 of this Schedule.

3.2.5 Transmission Loss Charges.

Each Market Buyer shall be assessed Transmission Loss Charges as specified in Section 5 of this Schedule.

3.2.6 Emergency Energy.

(a) When the Office of the Interconnection has implemented Emergency procedures, resources offering Emergency energy are eligible to set real-time Locational Marginal Prices, capped at the energy offer cap plus the sum of the applicable Reserve Penalty Factors for the Synchronized Reserve Requirement and Primary Reserve Requirement, provided that the Emergency energy is needed to meet demand in the PJM Region.

(b) Market Participants shall be allocated a proportionate share of the net cost of Emergency energy purchased by the Office of the Interconnection. Such allocated share during each *applicable interval* of such Emergency energy purchase shall be in proportion to the amount of each Market Participant's real-time deviation from its net *withdrawals and injections* in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market sales. This deviation shall not include any reduction or suspension of output of pool scheduled resources requested by PJM to manage an Emergency within the PJM Region.

(c) Net revenues in excess of Real-time Prices attributable to sales of energy in connection with Emergencies to other Control Areas shall be credited to Market Participants during each *applicable interval* of such Emergency energy sale in proportion to the sum of (i) each Market Participant's real-time deviation from its net *withdrawals and injections* in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market sales, and (ii) each Market Participant's energy sales from within the PJM Region to entities outside the PJM Region that have been curtailed by PJM.

(d) The net costs or net revenues associated with sales or purchases of energy in connection with a Minimum Generation Emergency in the PJM Region, or in another Control Area, shall be allocated during each *applicable interval* of such Emergency sale or purchase to each Market Participant in proportion to the amount of each Market Participant's real-time deviation from its net *withdrawals and injections* in the Day-ahead Market, whenever that deviation increases the Market Participant's spot market sales or decreases its spot market purchases.

3.2.7 Billing.

(a) PJMSettlement shall prepare a billing statement each billing cycle for each Market *Participant* in accordance with the charges and credits specified in Sections 3.2.1 through 3.2.6 of this Schedule, and showing the net amount to be paid or received by the Market *Participant*. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts and completion of the Market *Participant's* internal accounting.

(b) If deliveries to a Market *Participant* that has PJM Interchange meters in accordance with Section 14 of the Operating Agreement include amounts delivered for a Market Participant that does not have PJM Interchange meters separate from those of the metered Market *Participant*, PJMSettlement shall prepare a separate billing statement for the unmetered Market Participant based on the allocation of deliveries agreed upon between the Market *Participant* and the unmetered Market Participant specified by them to the Office of the Interconnection.

Attachment B

PJM Open Access Transmission Tariff
and PJM Operating Agreement

(Clean Format)

Section(s) of the
PJM Open Access Transmission Tariff

(Clean Format)

3.2 Market *Settlements*.

If a dollar-per-MW-hour value is applied in a calculation under this section 3.2 where the interval of the value produced in that calculation is less than an hour, then for purposes of that calculation the dollar-per-MW hour value is divided by the number of Real-time Settlement Intervals in the hour.

3.2.1 Spot Market Energy.

(a) The Office of the Interconnection shall calculate System Energy Prices in the form of Day-ahead System Energy Prices and Real-time System Energy Prices for the PJM Region, in accordance with Section 2 of this Schedule.

(b) *Each* Market *Participant* shall be charged for all *of its Market Participant Energy Withdrawals* scheduled in the Day-ahead Energy Market at the Day-ahead System Energy Price *to be served in the PJM Interchange Energy Market.*

(c) *Each* Market *Participant* shall be paid for all *of its Market Participant Energy Injections* scheduled in the Day-ahead Energy Market at the Day-ahead System Energy Price *to be delivered to the PJM Interchange Energy Market*.

(d) For each Day-ahead Settlement Interval during an Operating Day, the Office of the Interconnection shall calculate Spot Market Energy charges for each Market Participant as the difference between the sum of its Market Participant Energy Withdrawals scheduled times the Day-ahead System Energy Price and the sum of its Market Participant Energy Injections scheduled times the Day-ahead System Energy Price.

(e) For each Real-time Settlement Interval during an Operating Day, the Office of the Interconnection shall calculate Spot Market Energy charges for each Market Participant as the difference between the sum of its real-time Market Participant Energy Withdrawals less its scheduled Market Participant Energy Withdrawals times the Real-time System Energy Price and the sum of its real-time Market Participant Energy Injections less scheduled Market Participant Energy Injections times the Real-time System Energy Price. The Revenue Data for Settlements determined for each Real-time Settlement Interval in accordance with section 3.1A of this Schedule shall be used in determining the real-time Market Participant Energy Withdrawals and Market Participant Energy Injections used to calculate Spot Market Energy charges under this subsection (e).

(f) For pool External Resources, the Office of the Interconnection shall model, based on an appropriate flow analysis, the megawatts of real-time energy injections to be delivered from each such resource to the corresponding Interface Pricing Point between adjacent Control Areas and the PJM Region.

3.2.2 Regulation.

(a) Each Market *Participant* that is a Load Serving Entity in a Regulation Zone shall have an hourly Regulation objective equal to its pro rata share of the Regulation requirements of such Regulation Zone for the hour, based on the Market *Participant's* total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Regulation Zone for the hour ("Regulation Obligation"). A Market *Participant with an* hourly Regulation *O*bligation shall be charged *the pro rata share of the sum of the quantity of regulation provided in each Real-time Settlement Interval times the clearing price for all Real-time Settlement Intervals in the hour associated with that obligation.*

(b) Each Market *Participant supplying Regulation in a Regulation Zone at the direction of the Office of the Interconnection* shall be credited for each of its resources such that the calculated credit for each increment of Regulation provided by each resource shall be the higher of: (i) the Regulation market-clearing price; or (ii) the sum of the applicable Regulation offers for a resource determined pursuant to Section 3.2.2A.1 of this Schedule, the unit-specific shoulder hour opportunity costs described in subsection (e) of this section, the unit-specific inter-temporal opportunity costs, and the unit-specific opportunity costs discussed in subsection (d) of this section.

(c) The total Regulation market-clearing price in each Regulation Zone shall be determined *for each Real-time Settlement Interval.* The total Regulation market-clearing price shall include: (i) the performance Regulation market-clearing price in a Regulation Zone that shall be calculated in accordance with subsection (g) of this section; (ii) the capability Regulation market-clearing price that shall be calculated in accordance with subsection (h) of this section; and (iii) a Regulation resource's unit-specific opportunity costs during the 5-minute period, determined as described in subsection (d) below, divided by the unit-specific benefits factor described in subsection (j) of this section and divided by the historic accuracy score of the resource from among the resources selected to provide Regulation. A resource's Regulation offer by any Market Seller that fails the three-pivotal supplier test set forth in section 3.2.2A.1 of this Schedule shall not exceed the cost of providing Regulation from such resource, plus twelve dollars, as determined pursuant to the formula in section 1.10.1A(e) of this Schedule.

(d) In determining the Regulation 5-minute clearing price for each Regulation Zone, the estimated unit-specific opportunity costs of a generation resource offering to sell Regulation in each regulating hour, except for hydroelectric resources, shall be equal to the product of (i) the deviation of the set point of the generation resource that is expected to be required in order to provide Regulation from the generation resource's expected output level if it had been dispatched in economic merit order times, (ii) the absolute value of the difference between the expected Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource) in the PJM Interchange Energy Market.

For hydroelectric resources offering to sell Regulation in a regulating hour, the estimated unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the

PJM Manuals will be the full value of the Locational Marginal Price at that generation bus for each megawatt of Regulation capability.

The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and has a day-ahead megawatt commitment greater than zero shall be equal to the product of (i) the deviation of the set point of the hydroelectric resource that is expected to be required in order to provide Regulation from the hydroelectric resource's expected output level if it had been dispatched in economic merit order times (ii) the difference between the expected Locational Marginal Price at the generation bus for the hydroelectric resource and the average of the Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating. Estimated opportunity costs shall be zero for hydroelectric resources for which the average Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period, excluding those *Real-time Settlement Intervals* during which all available units at the hydroelectric resource were operating is higher than the actual Locational Marginal Price at the generator bus for the *Real-time Settlement Interval*.

The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead megawatt commitment greater than zero shall be equal to the product of (i) the deviation of the set point of the hydroelectric resource that is expected to be required in order to provide Regulation from the hydroelectric resource's expected output level if it had been dispatched in economic merit order times (ii) the difference between the average of the Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating and the expected Locational Marginal Price at the generation bus for the hydroelectric resource. Estimated opportunity costs shall be zero for hydroelectric resources for which the actual Locational Marginal Price at the generator bus for the *Real-time Settlement Interval* is higher than the average Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period, excluding those *Real-time Settlement Intervals* during which all available units at the hydroelectric resource were operating.

For the purpose of committing resources and setting Regulation market clearing prices, the Office of the Interconnection shall utilize day-ahead Locational Marginal Prices to calculate opportunity costs for hydroelectric resources. For the purposes of settlements, the Office of the Interconnection shall utilize the real-time Locational Marginal Prices to calculate opportunity costs for hydroelectric resources.

Estimated opportunity costs for Demand Resources to provide Regulation are zero.

(e) In determining the credit under subsection (b) to a Market *Participant* selected to provide Regulation in a Regulation Zone and that actively follows the Office of the Interconnection's Regulation signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for *(1)* each *Real-time Settlement Interval* that the Office of the Interconnection requires a generation resource to provide Regulation, and *(2)* the *last three*

Real-time Settlement Intervals of the preceding shoulder hour and the *first three Real-time Settlement Intervals of the* following shoulder hour *in accordance with the PJM Manuals and below*. The unit-specific opportunity cost incurred during the *Real-time Settlement Interval* in which the Regulation obligation is fulfilled shall be equal to the product of (i) the deviation of the generation resource‘s output necessary to follow the Office of the Interconnection‘s Regulation signals from the generation resource‘s expected output level if it had been dispatched in economic merit order times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the actual megawatt level of the resource when the actual megawatt level is within the tolerance defined in the PJM Manuals for the Regulation set point, or at the Regulation set point for the resource when it is not within the corresponding tolerance) in the PJM Interchange Energy Market. Opportunity costs for Demand Resources to provide Regulation are zero.

The unit-specific opportunity costs associated with uneconomic operation during *each of* the preceding *three Real-time Settlement Intervals of the* shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the initial regulating *Real-time Settlement Interval* in order to provide Regulation and the resource‘s expected output in *each of the* preceding *three Real-time Settlement Intervals of the* shoulder hour times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in *each of* the preceding *three Real-time Settlement Intervals of the* shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in the initial regulating *Real-time Settlement Interval*) in the PJM Interchange Energy Market, all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

The unit-specific opportunity costs associated with uneconomic operation during *each of* the following *three Real-time Settlement Intervals of the* shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the final regulating *Real-time Settlement Interval* in order to provide Regulation and the resource‘s expected output in *each of* the following *three Real-time Settlement Intervals of the* shoulder hour times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in *each of* the following *three Real-time Settlement Intervals of the* shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in final regulating hour) in the PJM Interchange Energy Market all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

(f) Any amounts credited for Regulation in an hour in excess of the Regulation market-clearing price in that hour shall be allocated and charged to each Market *Participant* in a Regulation Zone that does not meet its hourly Regulation obligation in proportion to its purchases of Regulation in such Regulation Zone in megawatt-hours during that hour.

(g) To determine the performance Regulation market-clearing price for each Regulation Zone, the Office of the Interconnection shall adjust the submitted performance offer for each resource in accordance with the historical performance of that resource, the amount of Regulation that resource will be dispatched based on the ratio of control signals calculated by the Office of the Interconnection, and the unit-specific benefits factor described in subsection (j) of this section for which that resource is qualified. The maximum adjusted performance offer of all cleared resources will set the performance Regulation market-clearing price.

The owner of each Regulation resource that actively follows the Office of the Interconnection's Regulation signals and instructions, will be credited for Regulation performance by multiplying the assigned MW(s) by the performance Regulation market-clearing price, by the ratio between the requested mileage for the Regulation dispatch signal assigned to the Regulation resource and the Regulation dispatch signal assigned to traditional resources, and by the Regulation resource's accuracy score calculated in accordance with subsection (k) of this section.

(h) The Office of the Interconnection shall divide each Regulation resource's capability offer by the unit-specific benefits factor described in subsection (j) of this section and divided by the historic accuracy score for the resource for the purposes of committing resources and setting the market clearing prices.

The Office of the Interconnection shall calculate the capability Regulation market-clearing price for each Regulation Zone by subtracting the performance Regulation market-clearing price described in subsection (g) from the total Regulation market clearing price described in subsection (c). This residual sets the capability Regulation market clearing price for that market *Real-time Settlement Interval*.

The owner of each Regulation resource that actively follows the Office of the Interconnection's Regulation signals and instructions will be credited for Regulation capability based on the assigned MW and the capability Regulation market-clearing price multiplied by the Regulation resource's accuracy score calculated in accordance with subsection (k) of this section.

(i) In accordance with the processes described in the PJM Manuals, the Office of the Interconnection shall: (i) calculate inter-temporal opportunity costs for each applicable resource; (ii) include such inter-temporal opportunity costs in each applicable resource's offer to sell frequency Regulation service; and (iii) account for such inter-temporal opportunity costs in the Regulation market-clearing price.

(j) The Office of the Interconnection shall calculate a unit-specific benefits factor for each of the dynamic Regulation signal and traditional Regulation signal in accordance with the PJM Manuals. Each resource shall be assigned a unit-specific benefits factor based on their order in the merit order stack for the applicable Regulation signal. The unit-specific benefits factor is the point on the benefits factor curve that aligns with the last megawatt, adjusted by historical performance, that resource will add to the dynamic resource stack. The unit-specific benefits factor for the traditional Regulation signal shall be equal to one.

(k) The Office of the Interconnection shall calculate each Regulation resource's accuracy score. The accuracy score shall be the average of a delay score, correlation score, and energy score for each ten second interval. For purposes of setting the interval to be used for the correlation score and delay scores, PJM will use the maximum of the correlation score plus the delay score for each interval.

The Office of the Interconnection shall calculate the correlation score using the following statistical correlation function (r) that measures the delay in response between the Regulation signal and the resource change in output:

$$\text{Correlation Score} = r_{\text{Signal,Response}(\delta,\delta+5\text{ Min});\ \delta=0\text{ to }5\text{ Min}}$$

where δ is delay.

The Office of the Interconnection shall calculate the delay score using the following equation:

Delay Score = Abs ((δ- 5 Minutes) / (5 Minutes)).

The Office of the Interconnection shall calculate a*n* energy score as a function of the difference in the energy provided versus the energy requested by the Regulation signal while scaling for the number of samples. The energy score is the absolute error (ε) as a function of the resource's Regulation capacity using the following equations:

Energy Score = 1 - 1/n ∑ Abs (Error);

Error = Average of Abs ((Response - Regulation Signal) / (Hourly Average Regulation Signal)); and

n = the number of samples in the hour and the energy.

The Office of the Interconnection shall calculate an accuracy score for each Regulation resource that is the average of the delay score, correlation score, and energy score for a five-minute period using the following equation where the energy score, the delay score, and the correlation score are each weighted equally:

Accuracy Score = max ((Delay Score) + (Correlation Score)) + (Energy Score).

The historic accuracy score will be based on a rolling average of the *Real-time Settlement Interval* accuracy scores, with consideration of the qualification score, as defined in the PJM Manuals.

3.2.2A Offer Price Caps.

3.2.2A.1 Applicability.

(a) Each hour, the Office of the Interconnection shall conduct a three-pivotal supplier test as described in this section. Regulation offers from Market Sellers that fail the three-pivotal supplier test shall be capped in the hour in which they failed the test at their cost based offers as determined pursuant to section 1.10.1A(e) of this Schedule. A Regulation supplier fails the three-pivotal supplier test in any hour in which such Regulation supplier and the two largest other Regulation suppliers are jointly pivotal.

(b) For the purposes of conducting the three-pivotal supplier test pursuant to this section, the following applies:

(i) The three-pivotal supplier test will include in the definition of available supply all offers from resources capable of satisfying the Regulation requirement of the PJM Region multiplied by the historic accuracy score of the resource and multiplied by the unit-specific benefits factor for which the capability cost-based offer plus the performance cost-based offer plus any eligible opportunity costs is no greater than 150 percent of the clearing price that would be calculated if all offers were limited to cost (plus eligible opportunity costs).

(ii) The three-pivotal supplier test will apply on a Regulation supplier basis (i.e. not a resource by resource basis) and only the Regulation suppliers that fail the three-pivotal supplier test will have their Regulation offers capped. A Regulation supplier for the purposes of this section includes corporate affiliates. Regulation from resources controlled by a Regulation supplier or its affiliates, whether by contract with unaffiliated third parties or otherwise, will be included as Regulation of that Regulation supplier. Regulation provided by resources owned by a Regulation supplier but controlled by an unaffiliated third party, whether by contract or otherwise, will be included as Regulation of that third party.

(iii) Each supplier shall be ranked from the largest to the smallest offered megawatt of eligible Regulation supply adjusted by the historic performance of each resource and the unit-specific benefits factor. Suppliers are then tested in order, starting with the three largest suppliers. For 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 Regulation requirement for the hour to determine the residual supply index. Where the residual supply index for three pivotal suppliers 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 third supplier result in a residual supply index greater than 1.0, at which point the remaining suppliers pass the test. Any resource owner that fails the three-pivotal supplier test will be offer-capped.

3.2.3 Operating Reserves.

(a) A Market Seller's pool-scheduled resources capable of providing Operating Reserves shall be credited as specified below based on the applicable offer for the operation of such resource, provided that the resource was available for the entire time specified in the Offer Data for such resource. To the extent that Section 3.2.3A.01 of Schedule 1 of this Agreement does not meet the Day-ahead Scheduling Reserves Requirement, the Office of the Interconnection shall schedule additional Operating Reserves pursuant to Section 1.7.17 and 1.10 of Schedule 1 of this Agreement. In addition the Office of the Interconnection shall schedule Operating Reserves pursuant to those sections to satisfy any unforeseen Operating Reserve requirements that are not reflected in the Day-ahead Scheduling Reserves Requirement.

(b) The following determination shall be made for each pool-scheduled resource that is scheduled in the Day-ahead Energy Market: the total offered price for Start-up Costs and No-load Costs and energy, determined on the basis of the resource's scheduled output, shall be compared to the total value of that resource's energy – as determined by the Day-ahead Energy Market and the Day-ahead Prices applicable to the relevant generation bus in the Day-ahead Energy Market. PJM shall also (i) determine whether any resources were scheduled in the Day-ahead Energy Market to provide Black Start service, Reactive Services or transfer interface control during the Operating Day because they are known or expected to be needed to maintain system reliability in a Zone during the Operating Day in order to minimize the total cost of Operating Reserves associated with the provision of such services and reflect the most accurate possible expectation of real-time operating conditions in the day-ahead model, which resources would not have otherwise been committed in the day-ahead security-constrained dispatch and (ii) report on the day following the Operating Day the megawatt quantities scheduled in the Day-ahead Energy Market for the above-enumerated purposes for the entire RTO.

Except as provided in Section 3.2.3(n), if the total offered price for Start-up Costs (shutdown costs for Demand Resources) and No-load Costs and energy summed over all *Day-ahead Settlement Intervals* exceeds the total value summed over all *Day-ahead Settlement Intervals*, the difference shall be credited to the Market Seller.

The Office of the Interconnection shall apply any balancing Operating Reserve credits allocated pursuant to this Section 3.2.3(b) to real-time deviations or real-time load share plus exports, pursuant to Section 3.2.3(p), depending on whether the balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

(i) For resources scheduled by the Office of the Interconnection during the reliability analysis for an Operating Day, the associated balancing Operating Reserve credits shall be allocated based on the reason the resource was scheduled according to the following provisions:

(A) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to operate in real-time to augment the physical resources committed in the Day-ahead Energy Market to meet the forecasted real-time load plus the Operating Reserve requirement, the associated balancing Operating Reserve credits, identified as RA Credits for Deviations, shall be allocated to real-time deviations.

(B) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to maintain system reliability, the associated balancing Operating Reserve credits, identified as RA Credits for Reliability, shall be allocated according to ratio share of real time load plus export transactions.

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing Operating Reserves, the associated balancing Operating Reserve credits shall be segmented and separately allocated pursuant to subsections 3.2.3(b)(i)(A) or 3.2.3(b)(i)(B) hereof. Balancing Operating Reserve credits for such resources will be identified in the same manner as units committed during the reliability analysis pursuant to subsections 3.2.3(b)(i)(A) and 3.2.3(b)(i)(B) hereof.

(ii) For resources scheduled during an Operating Day, the associated balancing Operating Reserve credits shall be allocated according to the following provisions:

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Operating Reserve credits, identified as RT Credits for Reliability, shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, credits will be applied pursuant to this section only if the LMP at the resource's bus does not meet or exceed the applicable offer of the resource for at least four 5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the credits for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category (RT Credits for Reliability or RT Credits for Deviations) as identified for the Operating Reserves for the other discrete clock hours.

(B) If the Office of the Interconnection directs a resource not covered by Section 3.2.3(b)(ii)(A) hereof to operate in real-time during an Operating Day, the associated balancing Operating Reserve credits, identified as RT Credits for Deviations, shall be allocated according to real-time deviations from day-ahead schedules.

(iii) PJM shall post on its Web site the aggregate amount of MWs committed that meet the criteria referenced in subsections (b)(i) and (b)(ii) hereof.

(c) The sum of the foregoing credits calculated in accordance with Section 3.2.3(b) plus any unallocated charges from Section 3.2.3(h) and 5.1.7, and any shortfalls paid pursuant to the Market Settlement provision of the Day-ahead Economic Load Response Program, shall be the cost of Operating Reserves in the Day-ahead Energy Market.

(d) The cost of Operating Reserves in the Day-ahead Energy Market shall be allocated and charged to each Market Participant in proportion to the sum of its (i) scheduled load (net of Behind The Meter Generation expected to be operating, but not to be less than zero), accepted Decrement Bids in the Day-ahead Energy Market in megawatt-hours for that Operating Day, and the scheduled megawatt-hours at the specified sink of an accepted Up-to Congestion Transaction; and (ii) scheduled energy sales in the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours for that Operating Day, but not including its bilateral transactions that are Dynamic Transfers to load outside such area pursuant to Section 1.12, except to the extent PJM scheduled resources to provide Black Start service, Reactive Services or transfer interface control. The cost of Operating Reserves in the Day-ahead Energy Market for resources scheduled to provide Black Start service for the Operating Day which resources would not have otherwise been committed in the day-ahead security constrained dispatch shall be allocated by ratio share of the monthly transmission use of each Network Customer or Transmission Customer serving Zone Load or Non-Zone Load, as determined in accordance with the formulas contained in Schedule 6A of the PJM Tariff. The cost of Operating Reserves in the Day-ahead Energy Market for resources scheduled to provide Reactive Services or transfer interface control because they are known or expected to be needed to maintain system reliability in a Zone during the Operating Day and would not have otherwise been committed in the day-ahead security constrained dispatch shall be allocated and charged to each Market Participant in proportion to the sum of its real-time deliveries of energy to load (net of operating Behind The Meter Generation) in such Zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such Zone.

(e) At the end of each Operating Day, the following determination shall be made for each synchronized pool-scheduled resource of each Market Seller that operates as requested by the Office of the Interconnection. For each calendar day, pool-scheduled resources in the Real-time Energy Market shall be made whole for each of the following Segments: 1) the greater of their day-ahead schedules *and* minimum run time *specified at the time of commitment* (minimum down time *specified at the time of commitment* for Demand Resources); and 2) any block of *Real-time Settlement Intervals* the resource operates at PJM's direction in excess of the greater of its day-ahead schedule *and* minimum run time *specified at the time of commitment* (minimum down time *specified at the time of commitment* for Demand Resources). For each calendar day, and for each synchronized start of a generation resource or PJM-dispatched economic load reduction, there will be a maximum of two Segments for each resource. Segment 1 will be the greater of the day-ahead schedule and minimum run time *specified at the time of commitment* (minimum down time *specified at the time of commitment* for Demand Resources) and Segment 2 will include the remainder of the contiguous *Real-time Settlement Intervals* when the resource is operating at the direction of the Office of the Interconnection, provided that a segment is limited to the Operating Day in which it commenced and cannot include any part of the following Operating Day.

A Generation Capacity Resource that operates outside of its unit-specific parameters will not receive Operating Reserve Credits nor be made whole for such operation when not dispatched by the Office of the Interconnection, unless the Market Seller of the Generation Capacity Resource can justify to the Office of the Interconnection that operation outside of such unit-specific parameters was the result of an actual constraint. Such Market Seller shall provide to the Market Monitoring Unit and the Office of the Interconnection its request to receive Operating Reserve Credits and/or to be made whole for such operation, along with documentation explaining in detail the reasons for operating its resource outside of its unit-specific parameters, within thirty calendar days following the issuance of billing statement for the Operating Day. The Market Seller shall also respond to additional requests for information from the Market Monitoring Unit and the Office of the Interconnection. The Market Monitoring Unit shall evaluate such request for compensation and provide its determination of whether there was an exercise of market power to the Office of the Interconnection by no later than twenty-five calendar days after receiving the Market Seller's request for compensation. The Office of the Interconnection shall make its determination whether the Market Seller justified that it is entitled to receive Operating Reserve Credits and/or be made whole for such operation of its resource for the day(s) in question, by no later than thirty calendar days after receiving the Market Seller's request for compensation.

Credits received pursuant to this section shall be equal to the positive difference between a resource's Total Operating Reserve Offer, and the total value of the resource's energy for hours in the Day-ahead Energy Market that correspond to five-minute intervals in which the resource is operated in real-time pursuant to the Office of the Interconnection's direction, plus any credit or change for quantity deviations, at PJM dispatch direction (excluding quantity deviations caused by an increase in the Market Seller's Real-time Offer), from the Day-ahead Energy Market during the Operating Day at the real-time LMP(s) applicable to the relevant generation bus in the Real-time Energy Market. The foregoing notwithstanding, credits for segment 2 shall exclude start up (shutdown costs for Demand Resources) costs for generation resources.

Except as provided in Section 3.2.3(m), if the total offered price exceeds the total value, the difference less any credit as determined pursuant to Section 3.2.3(b), and less any amounts credited for Synchronized Reserve in excess of the Synchronized Reserve offer plus the resource's opportunity cost, and less any amounts credited for Non-Synchronized Reserve in excess of the Non-Synchronized Reserve offer plus the resource's opportunity cost, and less any amounts credited for providing Reactive Services as specified in Section 3.2.3B, and less any amounts for Day-ahead Scheduling Reserve in excess of the Day-ahead Scheduling Reserve offer plus the resource's opportunity cost, shall be credited to the Market Seller.

Synchronized Reserve, Non-Synchronized Reserve, and *Real-time Settlement Interval share of the* Day-ahead Scheduling Reserve credits applied against Operating Reserve credits pursuant to this section shall be netted against the Operating Reserve credits earned in the corresponding *Real-time Settlement Interval*(s) in which the Synchronized Reserve, Non-Synchronized Reserve, and Day-ahead Scheduling Reserve credits accrued, provided that for condensing combustion turbines, Synchronized Reserve credits will be netted against the total Operating Reserve credits accrued during each *Real-time Settlement Interval* the unit operates in condensing and generation mode.

(f) A Market Seller of a unit not defined in subsection (f-1), (f-2), or (f-4) hereof (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited *for each Real-time Settlement Interval* in an amount equal to the product of (A) the deviation of the generating unit's output necessary to follow the Office of the Interconnection's signals and the generating unit's expected output level if it had been dispatched in economic merit order, times (B) the Locational Marginal Price at the generation bus for the generating unit, minus (C) the Total Lost Opportunity Cost Offer, provided that the resulting outcome is greater than $0.00. This equation is represented as (A*B) - C.

(f-1) With the exception of Market Sellers of Flexible Resources that submit a Real-time Offer greater than their resource's Committed Offer in the Day-ahead Energy Market, a Market Seller of a Flexible Resource, shall be compensated for lost opportunity cost, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Generation Resource Maximum Output, if either of the following conditions occur:

(i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as directed by the PJM dispatcher), then the Market Seller shall be credited in a manner consistent with that described in section 3.2.3 (f).

(ii) *If the unit* is scheduled to produce energy in the Day-ahead Energy Market *for a Day-ahead Settlement Interval*, but the unit is not called on by the Office of the Interconnection and does not operate in *the corresponding Real-time Settlement Interval(s)*, then the Market Seller shall be credited in an amount equal to the higher of:

1) the product of (A) the amount of megawatts committed in the Day-ahead Energy Market for the generating unit, and (B) the Real-time Price at the generation bus for the generating unit, minus the sum of (C) the Total Lost Opportunity Cost Offer plus No-load Costs, plus (D) the Start-up Cost, divided by the *Real-time Settlement Intervals* committed for each set of contiguous hours for which the unit was scheduled in Day-ahead Energy Market. This equation is represented as (A*B) - (C+D). The startup cost, (D), shall be excluded from this calculation if the unit operates in real time following the Office of the Interconnection's direction during any portion of the set

of contiguous hours for which the unit was scheduled in Day-ahead Energy Market, or

2) the Real-time Price at the unit's bus minus the Day-ahead Price at the unit's bus, multiplied by the number of megawatts committed in the Day-ahead Energy Market for the generating unit.

Market Sellers of Flexible Resources that submit a Real-time Offer greater than their resource's Committed Offer in the Day-ahead Energy Market shall not be eligible to receive compensation for lost opportunity costs under any applicable provisions of Schedule 1 of this Agreement.

(f-2) A Market Seller of a hydroelectric resource that is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), the output of which is altered at the request of the Office of the Interconnection from the schedule submitted by the owner, due to a transmission constraint or other reliability issue, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(f-3) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for opportunity cost associated with following PJM dispatch instructions and reducing or suspending a unit's output due to a transmission constraint or other reliability issue, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of opportunity cost compensation, the Office of the Interconnection shall invoice the Market Seller accordingly. If the Market Monitoring Unit disagrees with the modified amount of opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(f-4) A Market Seller *of a* wind generating unit that is pool-scheduled or self-scheduled, has SCADA capability to transmit and receive instructions from the Office of the Interconnection, has provided data and established processes to follow PJM basepoints pursuant to the requirements for wind generating units as further detailed in this Agreement, the Tariff and the PJM Manuals, and which is operating as requested by the Office of the Interconnection, the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited *for each Real-time Settlement Interval* in an amount equal to the product of (A) the deviation of the generating unit's output necessary to follow the Office of the Interconnection's signals and the generating unit's expected output level if it had been dispatched in economic merit order, times (B) the Real-time Price at the generation bus for the generating unit, minus (C) the Total Lost Opportunity Cost Offer, provided that the resulting outcome is greater than $0.00. This equation is represented as (A*B) - C.

(g) The sum of the foregoing credits, plus any cancellation fees paid in accordance with Section 1.10.2(d), such cancellation fees to be applied to the Operating Day for which the unit was scheduled, plus any shortfalls paid pursuant to the Market Settlement provision of the real-time Economic Load Response Program, less any payments received from another Control Area for Operating Reserves shall be the cost of Operating Reserves for the Real-time Energy Market in each Operating Day.

(h) The cost of Operating Reserves for the Real-time Energy Market for each Operating Day, except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, shall be allocated and charged to each Market Participant *based on their daily total of hourly deviations determined in accordance with the following equation:*

$\sum_h (A + B + C)$

Where:

h = the hours in the applicable Operating Day;

A = For each Real-Time Settlement Interval in an hour, the sum of the absolute value of the withdrawal deviations (in MW) between the quantities scheduled in the Day-ahead Energy Market and the Market Participant's energy withdrawals (net of operating Behind The Meter Generation) in the Real-Time Energy Market, except as noted in subsection (h)(ii) below and in the PJM Manuals *divided by the number of Real-time Settlement Intervals for that hour. The summation of each Real-time Settlement Interval's withdrawal deviation in an hour will be the Market Participant's total hourly withdrawal deviations. Market Participant bilateral transactions that are Dynamic Transfers to load outside the PJM Region pursuant to section 1.12 of this Schedule are not included in the determination of withdrawal deviation*s;

B = For each Real-Time Settlement Interval in an hour, the sum of the absolute value of generation deviations (*in MW and* not including deviations in Behind The Meter Generation) *as determined in subsection (o) divided by the number of Real-Time Settlement Intervals for that hour*;

C = For each Real-Time Settlement Interval in an hour, the sum of the absolute value of the injection deviations (in MW) between the quantities scheduled in the Day-ahead Energy Market and the Market Participant's energy injections in the Real-Time Energy Market divided by the number of Real-time Settlement Intervals for that hour. The summation of the injection deviations for each Real-time Settlement Interval in an hour will be the Market Participant's total hourly injection deviations. The determination of injection deviations does not include generation resources.

The Revenue Data for Settlements determined for each Real-time Settlement Interval in accordance with section 3.1A of this Schedule shall be used in determining the real-time withdrawal deviations, generation deviations and injection deviations used to calculate Operating Reserve under this subsection (e).

The costs associated with scheduling of units for Black Start service or testing of Black Start Units shall be allocated by ratio share of the monthly transmission use of each Network Customer or Transmission Customer serving Zone Load or Non-Zone Load, as determined in accordance with the formulas contained in Schedule 6A of the PJM Tariff.

Notwithstanding section (h)(1) above, as more fully set forth in the PJM Manuals, load deviations from the Day-ahead Energy Market shall not be assessed Operating Reserves charges to the extent attributable to reductions in the load of Price Responsive Demand that is in response to an increase in Locational Marginal Price from the Day-ahead Energy Market to the Real-time Energy Market and that is in accordance with a properly submitted PRD Curve.

Deviations that occur within a single Zone shall be associated with the Eastern or Western Region, as defined in Section 3.2.3(q) of this Schedule, and shall be subject to the regional balancing Operating Reserve rate determined in accordance with Section 3.2.3(q). Deviations at a hub shall be associated with the Eastern or Western Region if all the buses that define the hub are located in the region. Deviations at an Interface Pricing Point shall be associated with whichever region, the Eastern or Western Region, with which the majority of the buses that define that Interface Pricing Point are most closely electrically associated. If deviations at interfaces and hubs are associated with the Eastern or Western region, they shall be subject to the regional balancing Operating Reserve rate. Demand and supply deviations shall be based on total activity in a Zone, including all aggregates and hubs defined by buses that are wholly contained within the same Zone.

The foregoing notwithstanding, netting deviations shall be allowed *for each Real-time Settlement Interval* in accordance with the following provisions:

(i) Generation resources with multiple units located at a single bus shall be able to offset deviations in accordance with the PJM Manuals to determine the net deviation MW at the relevant bus.

(ii) Demand deviations will be assessed by comparing all day-ahead demand transactions at a single transmission zone, hub, or interface against the real-time demand transactions at that same transmission zone, hub, or interface; except that the positive values of demand deviations, as set forth in the PJM Manuals, will not be assessed Operating Reserve charges in the event of a Primary Reserve or Synchronized Reserve shortage in real-time or where PJM initiates the request for emergency load reductions in real-time in order to avoid a Primary Reserve or Synchronized Reserve shortage. The scheduled megawatt-hour withdrawal at the specified sink for an accepted Decrement Bid or Up-to Congestion Transaction are included in the determination of demand deviations. Bilateral transactions inside the PJM Region, as defined in section 1.7.10 of this Schedule, will not be included in the determination of demand deviations.

(iii) Supply deviations will be assessed by comparing all day-ahead transactions at a single transmission zone, hub, or interface against the real-time transactions at that same transmission zone, hub, or interface. The scheduled megawatt-hour injection at the specified source for an accepted Increment Offer or Up-to Congestion Transaction are included in the determination of supply deviations. Bilateral transactions inside the PJM Region, as defined in section 1.7.10 of this Schedule, will not be included in the determination of supply deviations.

(i) At the end of each Operating Day, Market Sellers shall be credited on the basis of their offered prices for synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, as well as the credits calculated as specified in Section 3.2.3(b) for those generators committed solely for the purpose of providing synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, at the request of the Office of the Interconnection.

(j) The sum of the foregoing credits as specified in Section 3.2.3(i) shall be the cost of Operating Reserves for synchronous condensing for the PJM Region for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-contingency operation for the Operating Day and shall be separately determined for the PJM Region.

(k) The cost of Operating Reserves for synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-contingency operation for each Operating Day shall be allocated and charged to each Market Participant in proportion to the sum of its (i) deliveries of energy to load (net of operating Behind The Meter Generation, but not to be less than zero) in the PJM Region, served under Network Transmission Service, in megawatt-hours during that Operating Day; and (ii) deliveries of energy sales from within the PJM Region to load outside such region in megawatt-hours during that Operating Day, but not including its bilateral transactions that are Dynamic Transfers to load outside the PJM Region pursuant to Section 1.12, as compared to the sum of all such deliveries for all Market Participants.

(l) For any Operating Day in either, as applicable, the Day-ahead Energy Market or the Real-time Energy Market for which, for all or any part of such Operating Day, the Office of the Interconnection: (i) declares a Maximum Generation Emergency; (ii) issues an alert that a Maximum Generation Emergency may be declared ("Maximum Generation Emergency Alert"); or (iii) schedules units based on the anticipation of a Maximum Generation Emergency or a Maximum Generation Emergency Alert, the Operating Reserves credit otherwise provided by Section 3.2.3.(b) or Section 3.2.3(e) in connection with market-based offers shall be limited as provided in subsections (n) or (m), respectively. The Office of the Interconnection shall provide timely notice on its internet site of the commencement and termination of any of the actions described in subsection (i), (ii), or (iii) of this subsection (l) (collectively referred to as "MaxGen Conditions"). Following the posting of notice of the commencement of a MaxGen Condition, a Market Seller may elect to submit a cost-based offer in accordance with Schedule 2 of the Operating Agreement, in which case subsections (m) and (n) shall not apply to such offer; provided, however, that such offer must be submitted in accordance with the deadlines in Section 1.10 for the submission of offers in the Day-ahead Energy Market or Real-time Energy Market, as applicable. Submission of a cost-based offer under such conditions shall not be precluded by Section 1.9.7(b); provided, however, that the Market Seller must return to compliance with Section 1.9.7(b) when it submits its bid for the first Operating Day after termination of the MaxGen Condition.

(m) For the Real-time Energy Market, if the Effective Offer Price (as defined below) for a market-based offer is greater than $1,000/MWh and greater than the Market Seller's lowest available and applicable cost-based offer, the Market Seller shall not receive any credit for Operating Reserves. For purposes of this subsection (m), the Effective Offer Price shall be the amount that, absent subsections (l) and (m), would have been credited for Operating Reserves for such Operating Day pursuant to Section 3.2.3(e) plus the Real-time Energy Market revenues for the *Real-time Settlement Intervals* that the offer is economic divided by the megawatt hours of energy provided during the *Real-time Settlement Intervals* that the offer is economic. The *Real-time Settlement Intervals* that the offer is economic shall be: (i) the *Real-time Settlement Intervals* that the offer price for energy is less than or equal to the Real-time Price for the relevant generation bus, (ii) the *Real-time Settlement Intervals* in which the offer for energy is greater than Locational Marginal Price and the unit is operated at the direction of the Office of the Interconnection that are in addition to any *Real-time Settlement Intervals* required due to the minimum run time or other operating constraint of the unit, and (iii) for any unit with a minimum run time of one hour or less and with more than one start available per day, any hours the unit operated at the direction of the Office of the Interconnection.

(n) For the Day-ahead Energy Market, if notice of a MaxGen Condition is provided prior to 10:30 a.m. on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price for a market-based offer is greater than $1,000/MWh and greater than the Market Seller's lowest available and applicable cost-based offer, the Market Seller shall not receive any credit for Operating Reserves. If notice of a MaxGen Condition is provided after 10:30 a.m. on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than $1,000/MWh, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. If the Effective Offer Price is less than or equal to $1,000/MWh, regardless of when notice of a MaxGen Condition is provided, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. For purposes of this subsection (n), the Effective Offer Price shall be the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day divided by the megawatt hours of energy offered during the Specified Hours, plus the offer for energy during such hours. The Specified Hours shall be the lesser of: (1) the minimum run hours stated by the Market Seller in its Offer Data; and (2) either (i) for steam-electric generating units and for combined-cycle units when such units are operating in combined-cycle mode, the six consecutive hours of highest Day-ahead Price during such Operating Day when such units are running or (ii) for combustion turbine units and for combined-cycle units when such units are operating in combustion turbine mode, the two consecutive hours of highest Day-ahead Price during such Operating Day when such units are running. Notwithstanding any other provision in this subsection, the total compensation to a Market Seller on any Operating Day that includes a MaxGen Condition shall not exceed $1,000/MWh during the Specified Hours, where such total compensation in each such hour is defined as the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day pursuant to Section 3.2.3(b) divided by the Specified Hours, plus the Day-ahead Price for such hour, and no Operating Reserves payments shall be made for any other hour of such Operating Day. If a unit operates in real time at the direction of the Office of the Interconnection consistently with its day-ahead clearing, then subsection (m) does not apply.

(o) Dispatchable pool-scheduled generation resources and dispatchable self-scheduled generation resources that follow dispatch shall not be assessed balancing Operating Reserve deviations. Pool-scheduled generation resources and dispatchable self-scheduled generation resources that do not follow dispatch shall be assessed balancing Operating Reserve deviations in accordance with the calculations described below and in the PJM Manuals.

The Office of the Interconnection shall calculate a ramp-limited desired MW value for generation resources where the economic minimum and economic maximum are at least as far apart in real-time as they are in day-ahead according to the following parameters:

(i) real-time economic minimum <= 105% of day-ahead economic minimum or day-ahead economic minimum plus 5 MW, whichever is greater.

(ii) real-time economic maximum >= 95% day-ahead economic maximum or day-ahead economic maximum minus 5 MW, whichever is lower.

The ramp-limited desired MW value for a generation resource shall be equal to:

$$\mathbf{Ramp\_Request}_t = \left(\mathbf{UDStarget}_{t-1} - \mathbf{AOutput}_{t-1}\right) / \left(\mathbf{UDSLAtime}_{t-1}\right)$$

$$\mathbf{RL\_Desired}_t = \mathbf{AOutput}_{t-1} + \left(\mathbf{Ramp\_Request}_t * \mathbf{Case\_Eff\_time}_{t-1}\right)$$

where:

1. UDStarget = UDS basepoint for the previous UDS case
2. AOutput = Unit's output at case solution time
3. UDSLAtime = UDS look ahead time
4. Case_Eff_time = Time between base point changes
5. RL_Desired = Ramp-limited desired MW

To determine if a generation resource is following dispatch the Office of the Interconnection shall determine the unit's MW off dispatch and % off dispatch by using the lesser of the difference between the actual output and the UDS Basepoint or the actual output and ramp-limited desired MW value *for each Real-time Settlement Interval*. If the UDS Basepoint and the ramp-limited desired MW for the resource are unavailable, the Office of the Interconnection will determine the unit's MW off dispatch and % off dispatch by calculating the lesser of the difference between the actual output and the UDS LMP Desired MW *for each Real-time Settlement Interval*.

A pool-scheduled or dispatchable self-scheduled resource is considered to be following dispatch if its actual output is between its ramp-limited desired MW value and UDS Basepoint, or if its % off dispatch is <= 10, or its Real-time *Settlement Interval* MWh is within 5% of the *Real-time Settlement Interval* ramp-limited desired MW. A self-scheduled generator must also be dispatched above economic minimum. The degree of deviations for resources that are not following dispatch shall be determined *for each Real-time Settlement Interval* in accordance with the following provisions:

- A dispatchable self-scheduled resource that is not dispatched above economic minimum shall be assessed balancing Operating Reserve deviations according to the following formula: Real-time *Settlement Interval* MWh – Day-Ahead MWh.

- A resource that is dispatchable day-ahead but is Fixed Gen in real-time shall be assessed balancing Operating Reserve deviations according to the following formula: Real-time *Settlement Interval* MWh – UDS LMP Desired MW.

- Pool-scheduled generators that are not following dispatch shall be assessed balancing Operating Reserve deviations according to the following formula: Real-time *Settlement Interval* MWh – Ramp-Limited Desired MW.

- If a resource's real-time economic minimum is greater than its day-ahead economic minimum by 5% or 5 MW, whichever is greater, or its real-time economic maximum is less than its Day Ahead economic maximum by 5% or 5 MW, whichever is lower, and UDS LMP Desired MWh for the *Real-time Settlement Interval* is either below the real time economic minimum or above the real time economic maximum, then balancing Operating Reserve deviations for the resource shall be assessed according to the following formula: Real time *Settlement Interval* MWh – UDS LMP Desired MWh.

- If a resource is not following dispatch and its % Off Dispatch is <= 20%, balancing Operating Reserve deviations shall be assessed according to the following formula: Real-time *Settlement Interval MWh* – Ramp-Limited Desired MW. If deviation value is within 5% of Ramp-Limited Desired MW, balancing Operating Reserve deviations shall not be assessed.

- If a resource is not following dispatch and its % off Dispatch is > 20%, balancing Operating Reserve deviations shall be assessed according to the following formula: Real time *Settlement Interval* MWh – UDS LMP Desired MWh.

- If a resource is not following dispatch, and the resource has tripped, for the *Real-time Settlement Interval* the resource tripped and the *Real-time Settlement Intervals* it remains offline throughout its day-ahead schedule balancing Operating Reserve deviations shall be assessed according to the following formula: Real time *Settlement Interval* MWh – Day-Ahead MWh.

- For resources that are not dispatchable in both the Day-Ahead and Real-time Energy Markets balancing Operating Reserve deviations shall be assessed according to the following formula: Real-time *Settlement Interval* MWh - Day-Ahead MWh.

If a resource has a sum of the absolute value of generator deviations for an hour that is less than 5 MWh, then the resource shall not be assessed balancing Operating Reserve deviations for that hour.

(o-1) Dispatchable economic load reduction resources that follow dispatch shall not be assessed balancing Operating Reserve deviations. Economic load reduction resources that do not follow dispatch shall be assessed balancing Operating Reserve deviations as described in this subsection and as further specified in the PJM Manuals.

The Desired MW quantity for such resources for each hour shall be the hourly integrated MW quantity to which the load reduction resource was dispatched for each hour (where the hourly integrated value is the average of the dispatched values as determined by the Office of the Interconnection for the resource for each hour).

If the actual reduction quantity for the load reduction resource for a given hour deviates by no more than 20% above or below the Desired MW quantity, then no balancing Operating Reserve deviation will accrue for that hour. If the actual reduction quantity for the load reduction resource for a given hour is outside the 20% bandwidth, the balancing Operating Reserve deviations will accrue for that hour in the amount of the absolute value of (Desired MW – actual reduction quantity). For those hours where the actual reduction quantity is within the 20% bandwidth specified above, the load reduction resource will be eligible to be made whole for the total value of its offer as defined in section 3.3A of this Appendix. Hours for which the actual reduction quantity is outside the 20% bandwidth will not be eligible for the make-whole payment. If at least one hour is not eligible for make-whole payment based on the 20% criteria, then the resource will also not be made whole for its shutdown cost.

(p) The Office of the Interconnection shall allocate the charges assessed pursuant to Section 3.2.3(h) of Schedule 1 of this Agreement except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, to real-time deviations from day-ahead schedules or real-time load share plus exports depending on whether the underlying balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

(i) For resources scheduled by the Office of the Interconnection during the reliability analysis for an Operating Day, the associated balancing Operating Reserve charges shall be allocated based on the reason the resource was scheduled according to the following provisions:

(A) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to operate in real-time to augment the physical resources committed in the Day-ahead

Energy Market to meet the forecasted real-time load plus the Operating Reserve requirement, the associated balancing Operating Reserve charges shall be allocated to real-time deviations from day-ahead schedules.

(B) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to maintain system reliability, the associated balancing Operating Reserve charges shall be allocated according to ratio share of real time load plus export transactions.

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing Operating Reserves, the associated balancing Operating Reserve charges shall be allocated pursuant to (A) or (B) above.

(ii) For resources scheduled during an Operating Day, the associated balancing Operating Reserve charges shall be allocated according to the following provisions:

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Operating Reserve charges shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, charges will be assessed pursuant to this section only if the LMP at the resource's bus does not meet or exceed the applicable offer of the resource for at least four-5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the charges for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category as identified for the Operating Reserves for the other discrete clock hours.

(B) If the Office of the Interconnection directs a resource not covered by Section 3.2.3(h)(ii)(A) of Schedule 1 of this Agreement to operate in real-time during an Operating Day, the associated balancing Operating Reserve charges shall be allocated according to real-time deviations from day-ahead schedules.

(q) The Office of the Interconnection shall determine regional balancing Operating Reserve rates for the Western and Eastern Regions of the PJM Region. For the purposes of this section, the Western Region shall be the AEP, APS, ComEd, Duquesne, Dayton, ATSI, DEOK, EKPC transmission Zones, and the Eastern Region shall be the AEC, BGE, Dominion, PENELEC, PEPCO, ME, PPL, JCPL, PECO, DPL, PSEG, RE transmission Zones. The regional balancing Operating Reserve rates shall be determined in accordance with the following provisions:

(i) The Office of the Interconnection shall calculate regional adder rates for the Eastern and Western Regions. Regional adder rates shall be equal to the total balancing Operating Reserve credits paid to generators for transmission constraints that occur on transmission system capacity equal to or less than 345kv. The regional adder rates shall be separated into reliability and deviation charges, which shall be allocated to real-time load or real-time deviations, respectively. Whether the underlying credits are designated as reliability or deviation charges shall be determined in accordance with Section 3.2.3(p).

(ii) The Office of the Interconnection shall calculate RTO balancing Operating Reserve rates. RTO balancing Operating Reserve rates shall be equal to balancing Operating Reserve credits except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, in excess of the regional adder rates calculated pursuant to Section 3.2.3(q)(i) of Schedule 1 of this Agreement. The RTO balancing Operating Reserve rates shall be separated into reliability and deviation charges, which shall be allocated to real-time load or real-time deviations, respectively. Whether the underlying credits are allocated as reliability or deviation charges shall be determined in accordance with Section 3.2.3(p).

(iii) Reliability and deviation regional balancing Operating Reserve rates shall be determined by summing the relevant RTO balancing Operating Reserve rates and regional adder rates.

(iv) If the Eastern and/or Western Regions do not have regional adder rates, the relevant regional balancing Operating Reserve rate shall be the reliability and/or deviation RTO balancing Operating Reserve rate.

(r) Market Sellers that incur incremental operating costs for a generation resource *that are either* greater than $*1*,000/MWh *as* determined in accordance with the *Market Seller's PJM-approved Fuel Cost Policy,* Schedule 2 of the Operating Agreement and PJM Manual 15, *but are not verified at the time of dispatch of the resource under section 6.4.3 of this Schedule, or greater than $2,000/MWh as determined in accordance with the Market Seller's PJM-approved Fuel Cost Policy, Schedule 2 of the Operating Agreement, and PJM Manual 15,* will be eligible to receive credit for Operating Reserves upon review of the Market Monitoring Unit and the Office of the Interconnection, and approval of the Office of the Interconnection. Market Sellers must submit to the Office of the Interconnection and the Market Monitoring Unit all relevant documentation demonstrating the calculation of costs greater than *$2,000/MWh, and costs greater than* $*1*,000/MWh *which were not verified at the time of dispatch of the resource under section 6.4.3 of this Schedule.* The Office of the Interconnection must approve any Operating Reserve credits paid to a Market Seller under this subsection (r).

3.2.3A Synchronized Reserve.

(a) Each Market Participant that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Synchronized Reserve equal to its pro rata share of Synchronized Reserve requirements for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market *Participant's* total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone or Reserve Sub-zone for the hour ("Synchronized Reserve Obligation"), less any amount obtained from condensers associated with provision of Reactive Services as described in section 3.2.3B(i) and any amount obtained from condensers associated with post-contingency operations, as described in section 3.2.3C(b). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. A Market Participant *with an* hourly Synchronized Reserve Obligation shall be charged *the pro rata share of the sum of the quantity of Synchronized Reserves provided in each Real-time Settlement Interval times the clearing price for all Real-time Settlement Intervals in the hour associated with that obligation*.

(b) A resource supplying Synchronized Reserve at the direction of the Office of the Interconnection, in excess of its hourly Synchronized Reserve Obligation, shall be credited as follows:

i) Credits for Synchronized Reserve provided by generation resources that are then subject to the energy dispatch signals and instructions of the Office of the Interconnection and that increase their current output or Demand Resources that reduce their load in response to a Synchronized Reserve Event ("Tier 1 Synchronized Reserve") shall be at the Synchronized Energy Premium Price*, as described in 3.2.3A (c)*, with the exception of those *Real-time Settlement Intervals* in which the Non-Synchronized Reserve Market Clearing Price for the applicable Reserve Zone or Reserve Sub-zone is not equal to zero. During such hours, Tier 1 Synchronized Reserve resources shall be compensated at the Synchronized Reserve Market Clearing Price for the applicable Reserve Zone or Reserve Sub-zone for the lesser of the amount of Tier 1 Synchronized Reserve attributed to the resource as calculated by the Office of the Interconnection, or the actual amount of Tier 1 Synchronized Reserve provided should a Synchronized Reserve Event occur *in a Real-time Settlement Interval*.

ii) Credits for Synchronized Reserve provided by generation resources that are synchronized to the grid but, at the direction of the Office of the Interconnection, are operating at a point that deviates from the Office of the Interconnection energy dispatch signals and instructions ("Tier 2 Synchronized Reserve") shall be the higher of (i) the Synchronized Reserve Market Clearing Price or (ii) the sum of (A) the Synchronized Reserve offer, and (B) the specific opportunity cost of the generation resource supplying the increment of Synchronized Reserve, as determined by the Office of the Interconnection *to a Synchronized Reserve Event in a Real-time Settlement Interval* in accordance with procedures specified in the PJM Manuals.

iii) Credits for Synchronized Reserve provided by Demand Resources that are synchronized to the grid and accept the obligation to reduce load in response to a Synchronized Reserve Event *in a Real-time Settlement Interval* initiated by the Office of the Interconnection shall be the sum of (i) the higher of (A) the Synchronized Reserve offer or (B) the Synchronized Reserve Market Clearing Price and (ii) if a Synchronized

Reserve Event is actually initiated by the Office of the Interconnection and the Demand Resource reduced its load in response to the event, the fixed costs associated with achieving the load reduction, as specified in the PJM Manuals.

(c) The Synchronized Reserve Energy Premium Price is an adder in an amount to be determined periodically by the Office of the Interconnection not less than fifty dollars and not to exceed one hundred dollars per megawatt hour.

(d) The Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each *Real-time Settlement Interval* of the Operating Day. The hourly Synchronized Reserve Market Clearing Price shall be calculated as the 5-minute clearing price. Each 5-minute clearing price shall be calculated as the marginal cost of serving the next increment of demand for Synchronized Reserve in each Reserve Zone or Reserve Sub-zone, inclusive of Synchronized Reserve offer prices and opportunity costs. When the Synchronized Reserve Requirement or Extended Synchronized Reserve Requirement in a Reserve Zone or Reserve Sub-zone cannot be met, the 5-minute clearing price shall be at least greater than or equal to the applicable Reserve Penalty Factor for the Reserve Zone or Reserve Sub-zone, but less than or equal to the sum of the Reserve Penalty Factors for the Synchronized Reserve Requirement and Primary Reserve Requirement for the Reserve Zone or Reserve Sub-zone. If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a Voltage Reduction Action as described in the PJM Manuals or a Manual Load Dump Action as described in the PJM Manuals, the 5-minute clearing price shall be the sum of the Reserve Penalty Factors for the Primary Reserve Requirement and the Synchronized Reserve Requirement for that Reserve Zone or Reserve Sub-zone.

The Reserve Penalty Factor for the Synchronized Reserve Requirement shall be $850/MWh.

The Reserve Penalty Factor for the Extended Synchronized Reserve Requirement shall be $300/MWh.

By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to prices exceeding $1,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Synchronized Reserve Penalty Factors are warranted for subsequent Delivery Year(s).

(e) *For each Real-time Settlement Interval and for* determining the 5-minute Synchronized Reserve clearing price, the estimated unit-specific opportunity cost for a generation resource *will be determined in accordance with the following equation:*

(A x B) + (C x D)

Where:

A = *T*he Locational Marginal Price at the generation bus for the generation resource*;*

B = *T*he megawatts of energy used to provide Synchronized Reserve submitted as part of the Synchronized Reserve offer*;*

*C = T*he deviation of the set point of the generation resource that is expected to be required in order to provide Synchronized Reserve from the generation resource's expected output level if it had been dispatched in economic merit order*;and*

*D=T*he difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource.

The opportunity costs for a Demand Resource shall be zero.

(f) In determining the credit under subsection (b) to a resource selected to provide Tier 2 Synchronized Reserve and that actively follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each *Real-time Settlement Interval* that the Office of the Interconnection requires a generation resource to provide Tier 2 Synchronized Reserve and shall be *in accordance with the following equation:*

(A x B) + (C x D)

Where:

A *= T*he megawatts of energy used by the resource to provide Synchronized Reserve as submitted as part of the generation resource's Synchronized Reserve offer*;*

B *= T*he Locational Marginal Price at the generation bus of the generation resource*;*

*C = T*he deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order*; and*

*D = T*he difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the generation resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource.

The opportunity costs for a Demand Resource shall be zero.

(g) Charges for Tier 1 Synchronized Reserve will be allocated in proportion to the amount of Tier 1 Synchronized Reserve applied to each Synchronized Reserve Obligation. In the event Tier 1 Synchronized Reserve is provided by a Market *Participant* in excess of that

Market *Participant's* Synchronized Reserve Obligation, the Tier 1 Synchronized Reserve that is not utilized to fulfill the *Market Participant's* obligation will be allocated proportionately among all other Synchronized Reserve Obligations.

(h) Any amounts credited for Tier 2 Synchronized Reserve in a *Real-time Settlement Interval* in excess of the Synchronized Reserve Market Clearing Price in that *Real-time Settlement Interval* shall be allocated and charged to each Market Participant that does not meet its hourly Synchronized Reserve Obligation in proportion to its purchases of Synchronized Reserve in megawatt-hours during that hour.

(i) In the event the Office of the Interconnection needs to assign more Tier 2 Synchronized Reserve during a *Real-time Settlement Interval* than was estimated as needed at the time the Synchronized Reserve Market Clearing Price was calculated for that *Real-time Settlement Interval* due to a reduction in available Tier 1 Synchronized Reserve, the costs of the excess Tier 2 Synchronized Reserve shall be allocated and charged to those providers of Tier 1 Synchronized Reserve whose available Tier 1 Synchronized Reserve was reduced from the needed amount estimated during the Synchronized Reserve Market Clearing Price calculation, in proportion to the amount of the reduction in Tier 1 Synchronized Reserve availability.

(j) In the event a generation resource or Demand Resource that either has been assigned by the Office of the Interconnection or self-scheduled to provide Tier 2 Synchronized Reserve fails to provide the assigned or self-scheduled amount of Tier 2 Synchronized Reserve in response to a Synchronized Reserve Event, the resource will be credited for Tier 2 Synchronized Reserve capacity in the amount that actually responded for all *Real-time Settlement Intervals* the resource was assigned or self-scheduled Tier 2 Synchronized Reserve on the Operating Day during which the event occurred. The determination of the amount of Synchronized Reserve credited to a resource shall be on an individual resource basis, not on an aggregate basis.

The resource shall refund payments received for Tier 2 Synchronized Reserve it failed to provide. For purposes of determining the amount of the payments to be refunded by a Market Participant, the Office of the Interconnection shall calculate the shortfall of Tier 2 Synchronized Reserve on an individual resource basis unless the Market Participant had multiple resources that were assigned or self-scheduled to provide Tier 2 Synchronized Reserve, in which case the shortfall will be determined on an aggregate basis. For performance determined on an aggregate basis, the response of any resource that provided more Tier 2 Synchronized Reserve than it was assigned or self-scheduled to provide will be used to offset the performance of other resources that provided less Tier 2 Synchronized Reserve than they were assigned or self-scheduled to provide during a Synchronized Reserve Event, as calculated in the PJM Manuals. The determination of a Market Participant's aggregate response shall not be taken into consideration in the determination of the amount of Tier 2 Synchronized Reserve credited to each individual resource.

The amount refunded shall be determined by multiplying the Synchronized Reserve Market Clearing Price by the amount of the shortfall of Tier 2 Synchronized Reserve, measured in megawatts, for all *intervals* the resource was assigned or self-scheduled to provide Tier 2

Synchronized Reserve for a period of time immediately preceding the Synchronized Reserve Event equal to the lesser of the average number of days between Synchronized Reserve Events, or the number of days since the resource last failed to provide the amount of Tier 2 Synchronized Reserve it was assigned or self-scheduled to provide in response to a Synchronized Reserve Event. The average number of days between Synchronized Reserve Events for purposes of this calculation shall be determined by an annual review of the twenty-four month period ending October 31 of the calendar year in which the review is performed, and shall be rounded down to a whole day value. The Office of the Interconnection shall report the results of its annual review to stakeholders by no later than December 31, and the average number of days between Synchronized Reserve Events shall be effective as of the following January 1. The refunded charges shall be allocated as credits to Market Participants based on its pro rata share of the Synchronized Reserve Obligation megawatts less any Tier 1 Synchronized Reserve applied to its Synchronized Reserve Obligation in the hour(s) of the Synchronized Reserve Event for the Reserve Sub-zone or Reserve Zone, except that Market Participants that incur a refund obligation and also have an applicable Synchronized Reserve Obligation during the hour(s) of the Synchronized Reserve Event shall not be included in the allocation of such refund credits. If the event spans multiple hours, the refund credits will be prorated hourly based on the duration of the event within each clock hour.

(k) The magnitude of response to a Synchronized Reserve Event by a generation resource or a Demand Resource, except for Batch Load Demand Resources covered by section 3.2.3A(l), is the difference between the generation resource’s output or the Demand Resource’s consumption at the start of the event and its output or consumption 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output or Demand Resource consumption at the start of the event is defined as the lowest telemetered generator resource output or greatest Demand Resource consumption between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output or a Demand Resource's consumption 10 minutes after the event is defined as the greatest generator resource output or lowest Demand Resource consumption achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter. The response actually credited to a Demand Resource will be reduced by the amount the megawatt consumption of the Demand Resource exceeds the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

(l) The magnitude of response by a Batch Load Demand Resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the start of a Synchronized Reserve Event shall be the difference between (i) the Batch Load Demand Resource’s consumption at the end of the Synchronized Reserve Event and (ii) the Batch Load Demand Resource’s consumption during the minute within the ten minutes after the end of the Synchronized Reserve Event in which the Batch Load Demand Resource’s consumption was highest and for which its consumption in all subsequent minutes within the ten minutes was not less than fifty percent of the consumption in such minute; provided that, the

magnitude of the response shall be zero if, when the Synchronized Reserve Event commences, the scheduled off-cycle stage of the production cycle is greater than ten minutes. .

3.2.3A.001 Non-Synchronized Reserve.

(a) Each Market Participant that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Non-Synchronized Reserve equal to its pro rata share of Non-Synchronized Reserve assigned for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market *Participant's* total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone and Reserve Sub-zone for the hour ("Non-Synchronized Reserve Obligation"). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. A Market Participant *with an* hourly Non-Synchronized Reserve Obligation shall be charged *the pro rata share of the sum of the quantity of Non-Synchronized Reserves provided in each Real-time Settlement Interval times the clearing price for all Real-time Settlement Intervals in the hour associated with that obligation*.

(b) Credits for Non-Synchronized Reserve provided by generation resources that are not operating for energy at the direction of the Office of the Interconnection specifically for the purpose of providing Non-Synchronized Reserve shall be the higher of (i) the Non-Synchronized Reserve Market Clearing Price or (ii) the specific opportunity cost of the generation resource supplying the increment of Non-Synchronized Reserve, as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

(c) The Non-Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each *Real-time Settlement Interval* of the Operating Day. The Non-Synchronized Reserve Market Clearing Price shall be calculated as the 5-minute clearing price. Each 5-minute clearing price shall be calculated as the marginal cost of procuring sufficient Non-Synchronized Reserves and/or Synchronized Reserves in each Reserve Zone or Reserve Sub-zone inclusive of opportunity costs associated with meeting the Primary Reserve Requirement or Extended Primary Reserve Requirement. When the Primary Reserve Requirement or Extended Primary Reserve Requirement in a Reserve Zone or Reserve Sub-zone cannot be met at a price less than or equal to the applicable Reserve Penalty Factor, the 5-minute clearing price for Non-Synchronized Reserve shall be at least greater than or equal to the applicable Reserve Penalty Factor for the Reserve Zone or Reserve Sub-zone, but less than or equal to the Reserve Penalty Factor for the Primary Reserve Requirement for the Reserve Zone or Reserve Sub-zone. If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a *V*oltage *R*eduction *A*ction as described in the PJM Manuals or a *M*anual *L*oad *D*ump *A*ction as described in the PJM Manuals, the 5-minute clearing price shall be the Reserve Penalty Factor for the Primary Reserve Requirement for that Reserve Zone or Reserve Sub-zone.

The Reserve Penalty Factor for the Synchronized Reserve Requirement shall be $850/MWh.

The Reserve Penalty Factor for the Extended Primary Reserve Requirement shall be $300/MWh.

By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to prices exceeding $1,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Primary Reserve Penalty Factors are warranted for subsequent Delivery Year(s).

(d) *For each Real-time Settlement Interval and for* determining the 5-minute Non-Synchronized Reserve clearing price, the unit-specific opportunity cost for a generation resource that is not providing energy because they are providing Non-Synchronized Reserves *will be determined in accordance with the following equation:*

(A x B) – C

Where:

A = *T*he deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order*;*

B =*T*he Locational Marginal Price at the generation bus for the generation resource*; and*
‘

C =*T*he applicable offer for energy from the generation resource in the PJM Interchange Energy Market.

(e) In determining the credit under subsection (b) to a resource selected to provide Non-Synchronized Reserve and that follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each *Real-time Settlement Interval* that the Office of the Interconnection requires a generation resource to provide Non- Synchronized Reserve and shall be *in accordance with the following equation:*

(A x B) – C

Where:

A = *T*he deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order*;*

B = *T*he Locational Marginal Price at the generation bus for the generation resource*; and*

C = *T*he applicable offer for energy from the generation resource in the PJM Interchange Energy Market.

(f) Any amounts credited for Non-Synchronized Reserve in a *Real-time Settlement Interval* in excess of the Non-Synchronized Reserve Market Clearing Price in that *Real-time Settlement Interval* shall be allocated and charged to each Market Participant that does not meet its hourly Non-Synchronized Reserve Obligation in proportion to its purchases of Non-Synchronized Reserve in megawatt-hours during that hour.

(g) The magnitude of response to a Non-Synchronized Reserve Event by a generation resource is the difference between the generation resource's output at the start of the event and its output 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output at the start of the event is defined as the lowest telemetered generator resource output between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output 10 minutes after the start of the event is defined as the greatest generator resource output achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

(h) In the event a generation resource that has been assigned by the Office of the Interconnection to provide Non-Synchronized Reserve fails to provide the assigned amount of Non-Synchronized Reserve in response to a Non-Synchronized Reserve Event, the resource will be credited for Non-Synchronized Reserve capacity in the amount that actually responded for the contiguous *Real-time Settlement Interval* the resource was assigned Non-Synchronized Reserve during which the event occurred.

3.2.3A.01 Day-ahead Scheduling Reserves.

(a) The Office of the Interconnection shall satisfy the Day-ahead Scheduling Reserves Requirement by procuring Day-ahead Scheduling Reserves in the Day-ahead Scheduling Reserves Market from Day-ahead Scheduling Reserves Resources, provided that Demand Resources shall be limited to providing the lesser of any limit established by the Reliability First Corporation or SERC, as applicable, or twenty-five percent of the total Day-ahead Scheduling Reserves Requirement. Day-ahead Scheduling Reserves Resources that clear in the Day-ahead Scheduling Reserves Market shall receive a Day-ahead Scheduling Reserves schedule from the Office of the Interconnection for the relevant Operating Day. PJMSettlement shall be the Counterparty to the purchases and sales of Day-ahead Scheduling Reserves in the PJM Interchange Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a self-schedule or self-supply of generation resources by a Market Buyer to satisfy its Day-ahead Scheduling Reserves Requirement.

(b) A Day-ahead Scheduling Reserves Resource that receives a Day-ahead Scheduling Reserves schedule pursuant to subsection (a) of this section shall be paid the hourly Day-ahead Scheduling Reserves Market clearing price for the cleared megawatt quantity of Day-ahead Scheduling Reserves in each hour of the schedule, subject to meeting the requirements of subsection (c) of this section.

(c) To be eligible for payment pursuant to subsection (b) of this section, Day-ahead Scheduling Reserves Resources shall comply with the following provisions:

(i) Generation resources with a start time greater than thirty minutes are required to be synchronized and operating at the direction of the Office of the Interconnection during the resource's Day-ahead Scheduling Reserves schedule and shall have a dispatchable range equal to or greater than the Day-ahead Scheduling Reserves schedule.

(ii) Generation resources and Demand Resources with start times or shut-down times, respectively, equal to or less than 30 minutes are required to respond to dispatch directives from the Office of the Interconnection during the resource's Day-ahead Scheduling Reserves schedule. To meet this requirement the resource shall be required to start or shut down within the specified notification time plus its start or shut down time, provided that such time shall be less than thirty minutes.

(iii) Demand Resources with a Day-ahead Scheduling Reserves schedule shall be credited based on the difference between the resource's MW consumption at the time the resource is directed by the Office of the Interconnection to reduce its load (starting MW usage) and the resource's MW consumption at the time when the Demand Resource is no longer dispatched by PJM (ending MW usage). For the purposes of this subsection, a resource's starting MW usage shall be the greatest telemetered consumption between one minute prior to and one minute following the issuance of a dispatch instruction from the Office of the Interconnection, and a resource's ending MW usage shall be the lowest consumption between one minute before and one minute after a dispatch instruction from the Office of the Interconnection that is no longer necessary to reduce.

(iv) Notwithstanding subsection (iii) above, the credit for a Batch Load Demand Resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the time the resource is directed by the Office of the Interconnection to reduce its load shall be the difference between (i) the "ending MW usage" (as defined above) and (ii) the Batch Load Demand Resource's consumption during the minute within the ten minutes after the time of the "ending MW usage" in which the Batch Load Demand Resource's consumption was highest and for which its consumption in all subsequent minutes within the ten minutes was not less than fifty percent of the consumption in such minute; provided that, the credit shall be zero if, at the time the resource is directed by the Office of the Interconnection to reduce its load, the scheduled off-cycle stage of the production cycle is greater than the timeframe for which the resource was dispatched by PJM.

Resources that do not comply with the provisions of this subsection (c) shall not be eligible to receive credits pursuant to subsection (b) of this section.

(d) The hourly credits paid to Day-ahead Scheduling Reserves Resources satisfying the Base Day-ahead Scheduling Reserves Requirement ("Base Day-ahead Scheduling Reserves credits") shall equal the ratio of the Base Day-ahead Scheduling Reserves Requirement to the Day-ahead Scheduling Reserves Requirement, multiplied by the total credits paid to Day-ahead Scheduling Reserves Resources, and are allocated as Base Day-ahead Scheduling Reserves charges per paragraph (i) below. The hourly credits paid to Day-ahead Scheduling Reserve Resources satisfying the Additional Day-ahead Scheduling Reserve Requirement ("Additional Day-ahead Scheduling Reserves credits") shall equal the ratio of the Additional Day-ahead Scheduling Reserves Requirement to the Day-ahead Scheduling Reserves Requirement, multiplied by the total credits paid to Day-ahead Scheduling Reserves Resources and are allocated as Additional Day-ahead Scheduling Reserves charges per paragraph (ii) below.

(i) A Market Participant's Base Day-ahead Scheduling Reserves charge is equal to the ratio of the Market Participant's hourly obligation to the total hourly obligation of all Market Participants in the PJM Region, multiplied by the Base Day-ahead Scheduling Reserves credits. The hourly obligation for each Market Participant is a megawatt representation of the portion of the Base Day-ahead Scheduling Reserves credits that the Market Participant is responsible for paying to PJM. The hourly obligation is equal to the Market Participant's load ratio share of the total megawatt volume of Base Day-ahead Scheduling Reserves resources (described below), based on the Market Participant's total hourly load (net of operating Behind The Meter Generation, but not to be less than zero) to the total hourly load of all Market Participants in the PJM Region. The total megawatt volume of Base Day-ahead Scheduling Reserves resources equals the ratio of the Base Day-ahead Scheduling Reserves Requirement to the Day-ahead Scheduling Reserves Requirement multiplied by the total volume of Day-ahead Scheduling Reserves megawatts paid pursuant to paragraph (c) of this section. A Market Participant's hourly Day-ahead Scheduling Reserves obligation can be further adjusted by any Day-ahead Scheduling Reserve bilateral transactions.

(ii) Additional Day-ahead Scheduling Reserves credits shall be charged hourly to Market Participants that are net purchasers in the Day-ahead Energy Market based on its positive demand difference ratio share. The positive demand difference for each Market Participant is the difference between its real-time load (net of operating Behind The Meter Generation, but not to be less than zero) and cleared Demand Bids in the Day-ahead Energy Market, net of cleared Increment Offers and cleared Decrement Bids in the Day-ahead Energy Market, when such value is positive. Net purchasers in the Day-ahead Energy Market are those Market Participants that have cleared Demand Bids plus cleared Decrement Bids in excess of its amount of cleared Increment Offers in the Day-ahead Energy Market. If there are no Market Participants with a positive demand difference, the Additional Day-ahead Scheduling Reserves credits are allocated according to paragraph (i) above.

(e) If the Day-ahead Scheduling Reserves Requirement is not satisfied through the operation of subsection (a) of this section, any additional Operating Reserves required to meet the requirement shall be scheduled by the Office of the Interconnection pursuant to Section 3.2.3 of Schedule 1 of this Agreement.

3.2.3B Reactive Services.

(a) A Market Seller providing Reactive Services at the direction of the Office of the Interconnection shall be credited as specified below for the operation of its resource. These provisions are intended to provide payments to generating units when the LMP dispatch algorithms would not result in the dispatch needed for the required reactive service. LMP will be used to compensate generators that are subject to redispatch for reactive transfer limits.

(b) At the end of each Operating Day, where the active energy output of a Market Seller's resource is reduced or suspended at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region, the Market Seller shall be credited according to Sections 3.2.3B(c) & 3.2.3B(d).

(c) A Market Seller providing Reactive Services from either a steam-electric generating unit or combined cycle unit operating in combined cycle mode, where such unit is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override) shall be compensated for lost opportunity cost by receiving a credit in an amount equal to the product of (A) the deviation of the generating unit's output necessary to follow the Office of the Interconnection's signals and the generating unit's expected output level if it had been dispatched in economic merit order, times (B) the Real-time Price at the generation bus for the generating unit, minus (C) the Total Lost Opportunity Cost Offer, provided that the resulting outcome is greater than $0.00. This equation is represented as (A*B) - C.

(d) A Market Seller providing Reactive Services from either a combustion turbine unit or combined cycle unit operating in simple cycle mode that is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost, limited to the lesser of the unit's Economic Maximum or the unit's Generation Resource Maximum Output, if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection as directed by the PJM dispatcher, then the Market Seller shall be credited in a manner consistent with that described above in Section 3.2.3B(c) for a steam unit or a combined cycle unit operating in combined cycle mode.

(e) At the end of each Operating Day, where the active energy output of a Market Seller's unit is increased at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region and the offered price of the energy is above the real-time LMP at the unit's bus, the Market Seller shall be credited according to Section 3.2.3B(f).

(f) A Market Seller providing Reactive Services from either a steam-electric generating unit, combined cycle unit or combustion turbine unit, where such unit is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the real time LMP at the unit's bus is lower than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall receive a credit hourly in an amount equal to {(AG - LMPDMW) x (UB - URTLMP)}where:

AG equals the actual output of the unit;

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the real time LMP at the unit's bus and adjusted for any Regulation or Tier 2 Synchronized Reserve assignments;

UB equals the unit offer for that unit for which output is increased, determined according to the lesser of the Final Offer or Committed Offer;

URTLMP equals the real time LMP at the unit's bus; and

where UB - URTLMP shall not be negative.

(g) A Market Seller providing Reactive Services from a hydroelectric resource where such resource is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the output of such resource is altered from the schedule submitted by the Market Seller for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(h) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for lost opportunity cost associated with following the Office of the Interconnection's dispatch instructions to reduce or suspend a unit's output for the purpose of maintaining reactive reliability, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of such alternate lost opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of alternate lost opportunity cost compensation, the Office of the Interconnection shall invoice the Market *Participant* accordingly. If the Market Monitoring Unit disagrees with the modified amount of alternate lost opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(i) The amount of Synchronized Reserve provided by generating units maintaining reactive reliability shall be counted as Synchronized Reserve satisfying the overall PJM Synchronized Reserve requirements. Operators of these generating units shall be notified of such provision, and to the extent a generating unit's operator indicates that the generating unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in Section 3.2.3A regarding provision of Tier 2 Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated to provide Reactive Services also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the Synchronized Reserve Market Clearing Price for each *Real-time Settlement Interval* a generating unit provided synchronous condensing multiplied by the amount of Synchronized reserve provided by the synchronous condenser or (ii) the sum of (A) the generating unit's cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the product of MW energy usage for providing synchronous condensing multiplied by the real time LMP at the generating unit's bus, (C) the generating unit's startup-cost of providing synchronous condensing, and (D) the unit-specific lost opportunity cost of the generating resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated to provide Reactive Services was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generating unit's cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to subsection (l) below.

(j) A Market Seller's pool scheduled steam-electric generating unit or combined cycle unit operating in combined cycle mode, that is not committed to operate in the Day-ahead Market, but that is directed by the Office of the Interconnection to operate solely for the purpose of maintaining reactive reliability, at the request of the Office of the Interconnection, shall be credited in the amount of the unit's offered price for start-up and no-load fees. The unit also shall receive, if applicable, compensation in accordance with Sections 3.2.3B(e)-(f).

(k) The sum of the foregoing credits as specified in Sections 3.2.3B(b)-(j) shall be the cost of Reactive Services for the purpose of maintaining reactive reliability for the Operating Day and shall be separately determined for each transmission zone in the PJM Region based on whether the resource was dispatched for the purpose of maintaining reactive reliability in such transmission zone.

(l) The cost of Reactive Services for the purpose of maintaining reactive reliability in a transmission zone in the PJM Region for each Operating Day shall be allocated and charged to each Market Participant in proportion to its deliveries of energy to load (net of operating Behind The Meter Generation) in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

(m) Generating units receiving dispatch instructions from the Office of the Interconnection under the expectation of increased actual or reserve reactive shall inform the Office of the Interconnection dispatcher if the requested reactive capability is not achievable. Should the operator of a unit receiving such instructions realize at any time during which said instruction is effective that the unit is not, or likely would not be able to, provide the requested amount of reactive support, the operator shall as soon as practicable inform the Office of the Interconnection dispatcher of the unit's inability, or expected inability, to provide the required reactive support, so that the associated dispatch instruction may be cancelled. PJM Performance Compliance personnel will audit operations after-the-fact to determine whether a unit that has altered its active power output at the request of the Office of the Interconnection has provided the actual reactive support or the reactive reserve capability requested by the Office of the Interconnection. PJM shall utilize data including, but not limited to, historical reactive performance and stated reactive capability curves in order to make this determination, and may withhold such compensation as described above if reactive support as requested by the Office of the Interconnection was not or could not have been provided.

3.2.3C Synchronous Condensing for Post-Contingency Operation.

(a) Under normal circumstances, PJM operates generation out of merit order to control contingency overloads when the flow on the monitored element for loss of the contingent element ("contingency flow") exceeds the long-term emergency rating for that facility, typically a 4-hour or 2-hour rating. At times however, and under certain, specific system conditions, PJM does not operate generation out of merit order for certain contingency overloads until the contingency flow on the monitored element exceeds the 30-minute rating for that facility ("post-contingency operation"). In conjunction with such operation, when the contingency flow on such element exceeds the long-term emergency rating, PJM operates synchronous condensers in the areas affected by such constraints, to the extent they are available, to provide greater certainty that such resources will be capable of producing energy in sufficient time to reduce the flow on the monitored element below the normal rating should such contingency occur.

(b) The amount of Synchronized Reserve provided by synchronous condensers associated with post-contingency operation shall be counted as Synchronized Reserve satisfying the PJM Synchronized Reserve requirements. Operators of these generation units shall be notified of such provision, and to the extent a generation unit's operator indicates that the generation unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in Section 3.2.3A regarding provision of Tier 2 Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated in conjunction with post-contingency operation also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing in conjunction with post-contingency operation at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the Synchronized Reserve Market Clearing Price for each *applicable interval* a generation resource provided synchronous condensing multiplied by the amount of Synchronized Reserve provided by the synchronous condenser or (ii) the sum of (A) the generation resource's *applicable interval* cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the *applicable interval* product of the megawatts of energy used to provide synchronous condensing multiplied by the real-time LMP at the generation bus of the generation resource, (C) the generation resource's start-up cost of providing synchronous condensing, and (D) the unit-specific lost opportunity cost of the generation resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated in association with post-contingency constraint control was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generation unit's cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to subsection (d) below.

(c) The sum of the foregoing credits as specified in section 3.2.3C(b) shall be the cost of synchronous condensers associated with post-contingency operations for the Operating Day and shall be separately determined for each transmission zone in the PJM Region based on whether the resource was dispatched in association with post-contingency operation in such transmission zone.

(d) The cost of synchronous condensers associated with post-contingency operations in a transmission zone in the PJM Region for each Operating Day shall be allocated and charged to each Market Participant in proportion to its deliveries of energy to load (net of operating Behind The Meter Generation) in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

3.2.4 Transmission Congestion Charges.

Each Market Buyer shall be assessed Transmission Congestion Charges as specified in Section 5 of this Schedule.

3.2.5 Transmission Loss Charges.

Each Market Buyer shall be assessed Transmission Loss Charges as specified in Section 5 of this Schedule.

3.2.6 Emergency Energy.

(a) When the Office of the Interconnection has implemented Emergency procedures, resources offering Emergency energy are eligible to set real-time Locational Marginal Prices, capped at the energy offer cap plus the sum of the applicable Reserve Penalty Factors for the Synchronized Reserve Requirement and Primary Reserve Requirement, provided that the Emergency energy is needed to meet demand in the PJM Region.

(b) Market Participants shall be allocated a proportionate share of the net cost of Emergency energy purchased by the Office of the Interconnection. Such allocated share during each *applicable interval* of such Emergency energy purchase shall be in proportion to the amount of each Market Participant's real-time deviation from its net *withdrawals and injections* in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market sales. This deviation shall not include any reduction or suspension of output of pool scheduled resources requested by PJM to manage an Emergency within the PJM Region.

(c) Net revenues in excess of Real-time Prices attributable to sales of energy in connection with Emergencies to other Control Areas shall be credited to Market Participants during each *applicable interval* of such Emergency energy sale in proportion to the sum of (i) each Market Participant's real-time deviation from its net *withdrawals and injections* in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market sales, and (ii) each Market Participant's energy sales from within the PJM Region to entities outside the PJM Region that have been curtailed by PJM.

(d) The net costs or net revenues associated with sales or purchases of energy in connection with a Minimum Generation Emergency in the PJM Region, or in another Control Area, shall be allocated during each *applicable interval* of such Emergency sale or purchase to each Market Participant in proportion to the amount of each Market Participant's real-time deviation from its net *withdrawals and injections* in the Day-ahead Market, whenever that deviation increases the Market Participant's spot market sales or decreases its spot market purchases.

3.2.7 Billing.

(a) PJMSettlement shall prepare a billing statement each billing cycle for each Market *Participant* in accordance with the charges and credits specified in Sections 3.2.1 through 3.2.6 of this Schedule, and showing the net amount to be paid or received by the Market *Participant*. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts and completion of the Market *Participant*'s internal accounting.

(b) If deliveries to a Market *Participant* that has PJM Interchange meters in accordance with Section 14 of the Operating Agreement include amounts delivered for a Market Participant that does not have PJM Interchange meters separate from those of the metered Market *Participant*, PJMSettlement shall prepare a separate billing statement for the unmetered Market Participant based on the allocation of deliveries agreed upon between the Market *Participant* and the unmetered Market Participant specified by them to the Office of the Interconnection.

Section(s) of the
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3.2 Market *Settlements.*

If a dollar-per-MW-hour value is applied in a calculation under this section 3.2 where the interval of the value produced in that calculation is less than an hour, then for purposes of that calculation the dollar-per-MW hour value is divided by the number of Real-time Settlement Intervals in the hour.

3.2.1 Spot Market Energy.

(a) The Office of the Interconnection shall calculate System Energy Prices in the form of Day-ahead System Energy Prices and Real-time System Energy Prices for the PJM Region, in accordance with Section 2 of this Schedule.

(b) *Each* Market *Participant* shall be charged for all *of its Market Participant Energy Withdrawals* scheduled in the Day-ahead Energy Market at the Day-ahead System Energy Price *to be served in the PJM Interchange Energy Market.*

(c) *Each* Market *Participant* shall be paid for all *of its Market Participant Energy Injections* scheduled in the Day-ahead Energy Market at the Day-ahead System Energy Price *to be delivered to the PJM Interchange Energy Market*.

(d) For each Day-ahead Settlement Interval during an Operating Day, the Office of the Interconnection shall calculate Spot Market Energy charges for each Market Participant as the difference between the sum of its Market Participant Energy Withdrawals scheduled times the Day-ahead System Energy Price and the sum of its Market Participant Energy Injections scheduled times the Day-ahead System Energy Price.

(e) For each Real-time Settlement Interval during an Operating Day, the Office of the Interconnection shall calculate Spot Market Energy charges for each Market Participant as the difference between the sum of its real-time Market Participant Energy Withdrawals less its scheduled Market Participant Energy Withdrawals times the Real-time System Energy Price and the sum of its real-time Market Participant Energy Injections less scheduled Market Participant Energy Injections times the Real-time System Energy Price. The Revenue Data for Settlements determined for each Real-time Settlement Interval in accordance with section 3.1A of this Schedule shall be used in determining the real-time Market Participant Energy Withdrawals and Market Participant Energy Injections used to calculate Spot Market Energy charges under this subsection (e).

(f) For pool External Resources, the Office of the Interconnection shall model, based on an appropriate flow analysis, the megawatts of real-time energy injections to be delivered from each such resource to the corresponding Interface Pricing Point between adjacent Control Areas and the PJM Region

3.2.2 Regulation.

(a) Each Market *Participant* that is a Load Serving Entity in a Regulation Zone shall have an hourly Regulation objective equal to its pro rata share of the Regulation requirements of such Regulation Zone for the hour, based on the Market *Participant's* total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Regulation Zone for the hour ("Regulation Obligation"). A Market *Participant with an* hourly Regulation *O*bligation shall be charged the *pro rata share of the sum of the quantity of regulation provided in each Real-time Settlement Interval times the clearing price for all Real-time Settlement Intervals in the hour associated with that obligation.*

(b) Each Market *Participant supplying Regulation in a Regulation Zone at the direction of the Office of the Interconnection* shall be credited for each of its resources such that the calculated credit for each increment of Regulation provided by each resource shall be the higher of: (i) the Regulation market-clearing price; or (ii) the sum of the applicable Regulation offers for a resource determined pursuant to Section 3.2.2A.1 of this Schedule, the unit-specific shoulder hour opportunity costs described in subsection (e) of this section, the unit-specific inter-temporal opportunity costs, and the unit-specific opportunity costs discussed in subsection (d) of this section.

(c) The total Regulation market-clearing price in each Regulation Zone shall be determined *for each Real-time Settlement Interval.* The total Regulation market-clearing price shall include: (i) the performance Regulation market-clearing price in a Regulation Zone that shall be calculated in accordance with subsection (g) of this section; (ii) the capability Regulation market-clearing price that shall be calculated in accordance with subsection (h) of this section; and (iii) a Regulation resource's unit-specific opportunity costs during the 5-minute period, determined as described in subsection (d) below, divided by the unit-specific benefits factor described in subsection (j) of this section and divided by the historic accuracy score of the resource from among the resources selected to provide Regulation. A resource's Regulation offer by any Market Seller that fails the three-pivotal supplier test set forth in section 3.2.2A.1 of this Schedule shall not exceed the cost of providing Regulation from such resource, plus twelve dollars, as determined pursuant to the formula in section 1.10.1A(e) of this Schedule.

(d) In determining the Regulation 5-minute clearing price for each Regulation Zone, the estimated unit-specific opportunity costs of a generation resource offering to sell Regulation in each regulating hour, except for hydroelectric resources, shall be equal to the product of (i) the deviation of the set point of the generation resource that is expected to be required in order to provide Regulation from the generation resource's expected output level if it had been dispatched in economic merit order times, (ii) the absolute value of the difference between the expected Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource) in the PJM Interchange Energy Market.

For hydroelectric resources offering to sell Regulation in a regulating hour, the estimated unit-specific opportunity costs for each hydroelectric resource in spill conditions as defined in the PJM Manuals will be the full value of the Locational Marginal Price at that generation bus for each megawatt of Regulation capability.

The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and has a day-ahead megawatt commitment greater than zero shall be equal to the product of (i) the deviation of the set point of the hydroelectric resource that is expected to be required in order to provide Regulation from the hydroelectric resource's expected output level if it had been dispatched in economic merit order times (ii) the difference between the expected Locational Marginal Price at the generation bus for the hydroelectric resource and the average of the Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating. Estimated opportunity costs shall be zero for hydroelectric resources for which the average Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period, excluding those *Real-time Settlement Intervals* during which all available units at the hydroelectric resource were operating is higher than the actual Locational Marginal Price at the generator bus for the *Real-time Settlement Interval*.

The estimated unit-specific opportunity costs for each hydroelectric resource that is not in spill conditions as defined in the PJM Manuals and does not have a day-ahead megawatt commitment greater than zero shall be equal to the product of (i) the deviation of the set point of the hydroelectric resource that is expected to be required in order to provide Regulation from the hydroelectric resource's expected output level if it had been dispatched in economic merit order times (ii) the difference between the average of the Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period as defined in the PJM Manuals, excluding those hours during which all available units at the hydroelectric resource were operating and the expected Locational Marginal Price at the generation bus for the hydroelectric resource. Estimated opportunity costs shall be zero for hydroelectric resources for which the actual Locational Marginal Price at the generator bus for the *Real-time Settlement Interval* is higher than the average Locational Marginal Price at the generation bus for the appropriate on-peak or off-peak period, excluding those *Real-time Settlement Intervals* during which all available units at the hydroelectric resource were operating.

For the purpose of committing resources and setting Regulation market clearing prices, the Office of the Interconnection shall utilize day-ahead Locational Marginal Prices to calculate opportunity costs for hydroelectric resources. For the purposes of settlements, the Office of the Interconnection shall utilize the real-time Locational Marginal Prices to calculate opportunity costs for hydroelectric resources.

Estimated opportunity costs for Demand Resources to provide Regulation are zero.

(e) In determining the credit under subsection (b) to a Market *Participant* selected to provide Regulation in a Regulation Zone and that actively follows the Office of the Interconnection's Regulation signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for *(1)* each *Real-time Settlement Interval* that the Office of the Interconnection requires a generation resource to provide Regulation, and *(2)* the *last three Real-time Settlement Intervals* of the preceding shoulder hour and the *first three Real-time*

Settlement Intervals of the following shoulder hour *in accordance with the PJM Manuals and below.*

The unit-specific opportunity cost incurred during the *Real-time Settlement Interval* in which the Regulation obligation is fulfilled shall be equal to the product of (i) the deviation of the generation resource‘s output necessary to follow the Office of the Interconnection‘s Regulation signals from the generation resource‘s expected output level if it had been dispatched in economic merit order times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the actual megawatt level of the resource when the actual megawatt level is within the tolerance defined in the PJM Manuals for the Regulation set point, or at the Regulation set point for the resource when it is not within the corresponding tolerance) in the PJM Interchange Energy Market. Opportunity costs for Demand Resources to provide Regulation are zero.

The unit-specific opportunity costs associated with uneconomic operation during *each of* the preceding *three Real-time Settlement Intervals of the* shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the initial regulating *Real-time Settlement Interval* in order to provide Regulation and the resource‘s expected output in *each of the* preceding *three Real-time Settlement Intervals of the* shoulder hour times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in *each of* the preceding *three Real-time Settlement Intervals of the* shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in the initial regulating *Real-time Settlement Interval*) in the PJM Interchange Energy Market, all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

The unit-specific opportunity costs associated with uneconomic operation during *each of* the following *three Real-time Settlement Intervals of the* shoulder hour shall be equal to the product of (i) the deviation between the set point of the generation resource that is expected to be required in the final regulating *Real-time Settlement Interval* in order to provide Regulation and the resource‘s expected output in *each of* the following *three Real-time Settlement Intervals of the* shoulder hour times (ii) the absolute value of the difference between the Locational Marginal Price at the generation bus for the generation resource in *each of* the following *three Real-time Settlement Intervals of the* shoulder hour and the lesser of the available market-based or highest available cost-based energy offer from the generation resource (at the megawatt level of the Regulation set point for the resource in final regulating hour) in the PJM Interchange Energy Market all as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

(f) Any amounts credited for Regulation in an hour in excess of the Regulation market-clearing price in that hour shall be allocated and charged to each Market *Participant* in a Regulation Zone that does not meet its hourly Regulation obligation in proportion to its purchases of Regulation in such Regulation Zone in megawatt-hours during that hour.

(g) To determine the performance Regulation market-clearing price for each Regulation Zone, the Office of the Interconnection shall adjust the submitted performance offer for each resource in accordance with the historical performance of that resource, the amount of Regulation that resource will be dispatched based on the ratio of control signals calculated by the Office of the Interconnection, and the unit-specific benefits factor described in subsection (j) of this section for which that resource is qualified. The maximum adjusted performance offer of all cleared resources will set the performance Regulation market-clearing price.

The owner of each Regulation resource that actively follows the Office of the Interconnection's Regulation signals and instructions, will be credited for Regulation performance by multiplying the assigned MW(s) by the performance Regulation market-clearing price, by the ratio between the requested mileage for the Regulation dispatch signal assigned to the Regulation resource and the Regulation dispatch signal assigned to traditional resources, and by the Regulation resource's accuracy score calculated in accordance with subsection (k) of this section.

(h) The Office of the Interconnection shall divide each Regulation resource's capability offer by the unit-specific benefits factor described in subsection (j) of this section and divided by the historic accuracy score for the resource for the purposes of committing resources and setting the market clearing prices.

The Office of the Interconnection shall calculate the capability Regulation market-clearing price for each Regulation Zone by subtracting the performance Regulation market-clearing price described in subsection (g) from the total Regulation market clearing price described in subsection (c). This residual sets the capability Regulation market clearing price for that market *Real-time Settlement Interval*.

The owner of each Regulation resource that actively follows the Office of the Interconnection's Regulation signals and instructions will be credited for Regulation capability based on the assigned MW and the capability Regulation market-clearing price multiplied by the Regulation resource's accuracy score calculated in accordance with subsection (k) of this section.

(i) In accordance with the processes described in the PJM Manuals, the Office of the Interconnection shall: (i) calculate inter-temporal opportunity costs for each applicable resource; (ii) include such inter-temporal opportunity costs in each applicable resource's offer to sell frequency Regulation service; and (iii) account for such inter-temporal opportunity costs in the Regulation market-clearing price.

(j) The Office of the Interconnection shall calculate a unit-specific benefits factor for each of the dynamic Regulation signal and traditional Regulation signal in accordance with the PJM Manuals. Each resource shall be assigned a unit-specific benefits factor based on their order in the merit order stack for the applicable Regulation signal. The unit-specific benefits factor is the point on the benefits factor curve that aligns with the last megawatt, adjusted by historical performance, that resource will add to the dynamic resource stack. The unit-specific benefits factor for the traditional Regulation signal shall be equal to one.

(k) The Office of the Interconnection shall calculate each Regulation resource's accuracy score. The accuracy score shall be the average of a delay score, correlation score, and energy score for each ten second interval. For purposes of setting the interval to be used for the correlation score and delay scores, PJM will use the maximum of the correlation score plus the delay score for each interval.

The Office of the Interconnection shall calculate the correlation score using the following statistical correlation function (r) that measures the delay in response between the Regulation signal and the resource change in output:

$$\text{Correlation Score} = r_{\text{Signal,Response}(\delta,\delta+5\text{ Min});\ \delta=0\text{ to }5\text{ Min}}$$

where δ is delay.

The Office of the Interconnection shall calculate the delay score using the following equation:

$$\text{Delay Score} = \text{Abs}\left((\delta - 5\text{ Minutes}) / (5\text{ Minutes})\right).$$

The Office of the Interconnection shall calculate a*n* energy score as a function of the difference in the energy provided versus the energy requested by the Regulation signal while scaling for the number of samples. The energy score is the absolute error (ε) as a function of the resource's Regulation capacity using the following equations:

$$\text{Energy Score} = 1 - 1/n \sum \text{Abs (Error)};$$

Error = Average of Abs ((Response - Regulation Signal) / (Hourly Average Regulation Signal)); and

n = the number of samples in the hour and the energy.

The Office of the Interconnection shall calculate an accuracy score for each Regulation resource that is the average of the delay score, correlation score, and energy score for a five-minute period using the following equation where the energy score, the delay score, and the correlation score are each weighted equally:

Accuracy Score = max ((Delay Score) + (Correlation Score)) + (Energy Score). The historic accuracy score will be based on a rolling average of the *Real-time Settlement Interval* accuracy scores, with consideration of the qualification score, as defined in the PJM Manuals.

3.2.2A Offer Price Caps.

3.2.2A.1 Applicability.

(a) Each hour, the Office of the Interconnection shall conduct a three-pivotal supplier test as described in this section. Regulation offers from Market Sellers that fail the three-pivotal supplier test shall be capped in the hour in which they failed the test at their cost based offers as determined pursuant to section 1.10.1A(e) of this Schedule. A Regulation supplier fails the three-pivotal supplier test in any hour in which such Regulation supplier and the two largest other Regulation suppliers are jointly pivotal.

(b) For the purposes of conducting the three-pivotal supplier test pursuant to this section, the following applies:

(i) The three-pivotal supplier test will include in the definition of available supply all offers from resources capable of satisfying the Regulation requirement of the PJM Region multiplied by the historic accuracy score of the resource and multiplied by the unit-specific benefits factor for which the capability cost-based offer plus the performance cost-based offer plus any eligible opportunity costs is no greater than 150 percent of the clearing price that would be calculated if all offers were limited to cost (plus eligible opportunity costs).

(ii) The three-pivotal supplier test will apply on a Regulation supplier basis (i.e. not a resource by resource basis) and only the Regulation suppliers that fail the three-pivotal supplier test will have their Regulation offers capped. A Regulation supplier for the purposes of this section includes corporate affiliates. Regulation from resources controlled by a Regulation supplier or its affiliates, whether by contract with unaffiliated third parties or otherwise, will be included as Regulation of that Regulation supplier. Regulation provided by resources owned by a Regulation supplier but controlled by an unaffiliated third party, whether by contract or otherwise, will be included as Regulation of that third party.

(iii) Each supplier shall be ranked from the largest to the smallest offered megawatt of eligible Regulation supply adjusted by the historic performance of each resource and the unit-specific benefits factor. Suppliers are then tested in order, starting with the three largest suppliers. For 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 Regulation requirement for the hour to determine the residual supply index. Where the residual supply index for three pivotal suppliers 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 third supplier result in a residual supply index greater than 1.0, at which point the remaining suppliers pass the test. Any resource owner that fails the three-pivotal supplier test will be offer-capped.

3.2.3 Operating Reserves.

(a) A Market Seller's pool-scheduled resources capable of providing Operating Reserves shall be credited as specified below based on the applicable offer for the operation of such resource, provided that the resource was available for the entire time specified in the Offer Data for such resource. To the extent that Section 3.2.3A.01 of Schedule 1 of this Agreement does not meet the Day-ahead Scheduling Reserves Requirement, the Office of the Interconnection shall schedule additional Operating Reserves pursuant to Section 1.7.17 and 1.10 of Schedule 1 of this Agreement. In addition the Office of the Interconnection shall schedule Operating Reserves pursuant to those sections to satisfy any unforeseen Operating Reserve requirements that are not reflected in the Day-ahead Scheduling Reserves Requirement.

(b) The following determination shall be made for each pool-scheduled resource that is scheduled in the Day-ahead Energy Market: the total offered price for Start-up Costs and No-load Costs and energy, determined on the basis of the resource's scheduled output, shall be compared to the total value of that resource's energy – as determined by the Day-ahead Energy Market and the Day-ahead Prices applicable to the relevant generation bus in the Day-ahead Energy Market. PJM shall also (i) determine whether any resources were scheduled in the Day-ahead Energy Market to provide Black Start service, Reactive Services or transfer interface control during the Operating Day because they are known or expected to be needed to maintain system reliability in a Zone during the Operating Day in order to minimize the total cost of Operating Reserves associated with the provision of such services and reflect the most accurate possible expectation of real-time operating conditions in the day-ahead model, which resources would not have otherwise been committed in the day-ahead security-constrained dispatch and (ii) report on the day following the Operating Day the megawatt quantities scheduled in the Day-ahead Energy Market for the above-enumerated purposes for the entire RTO.

Except as provided in Section 3.2.3(n), if the total offered price for Start-up Costs (shutdown costs for Demand Resources) and No-load Costs and energy summed over all *Day-ahead Settlement Intervals* exceeds the total value summed over all *Day-ahead Settlement Intervals*, the difference shall be credited to the Market Seller.

The Office of the Interconnection shall apply any balancing Operating Reserve credits allocated pursuant to this Section 3.2.3(b) to real-time deviations or real-time load share plus exports, pursuant to Section 3.2.3(p), depending on whether the balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

(i) For resources scheduled by the Office of the Interconnection during the reliability analysis for an Operating Day, the associated balancing Operating Reserve credits shall be allocated based on the reason the resource was scheduled according to the following provisions:

(A) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to operate in real-time to augment the physical resources committed in the Day-ahead Energy Market to meet the forecasted real-time load plus the Operating Reserve requirement, the associated balancing Operating Reserve credits, identified as RA Credits for Deviations, shall be allocated to real-time deviations.

(B) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to maintain system reliability, the associated balancing Operating Reserve credits, identified as RA Credits for Reliability, shall be allocated according to ratio share of real time load plus export transactions.

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing Operating Reserves, the associated balancing Operating Reserve credits shall be segmented and separately allocated pursuant to subsections 3.2.3(b)(i)(A) or 3.2.3(b)(i)(B) hereof. Balancing Operating Reserve credits for such resources will be identified in the same manner as units committed during the reliability analysis pursuant to subsections 3.2.3(b)(i)(A) and 3.2.3(b)(i)(B) hereof.

(ii) For resources scheduled during an Operating Day, the associated balancing Operating Reserve credits shall be allocated according to the following provisions:

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Operating Reserve credits, identified as RT Credits for Reliability, shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, credits will be applied pursuant to this section only if the LMP at the resource's bus does not meet or exceed the applicable offer of the resource for at least four 5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the credits for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category (RT Credits for Reliability or RT Credits for Deviations) as identified for the Operating Reserves for the other discrete clock hours.

(B) If the Office of the Interconnection directs a resource not covered by Section 3.2.3(b)(ii)(A) hereof to operate in real-time during an Operating Day, the associated balancing Operating Reserve credits, identified as RT Credits for Deviations, shall be allocated according to real-time deviations from day-ahead schedules.

(iii) PJM shall post on its Web site the aggregate amount of MWs committed that meet the criteria referenced in subsections (b)(i) and (b)(ii) hereof.

(c) The sum of the foregoing credits calculated in accordance with Section 3.2.3(b) plus any unallocated charges from Section 3.2.3(h) and 5.1.7, and any shortfalls paid pursuant to the Market Settlement provision of the Day-ahead Economic Load Response Program, shall be the cost of Operating Reserves in the Day-ahead Energy Market.

(d) The cost of Operating Reserves in the Day-ahead Energy Market shall be allocated and charged to each Market Participant in proportion to the sum of its (i) scheduled load (net of Behind The Meter Generation expected to be operating, but not to be less than zero), accepted Decrement Bids in the Day-ahead Energy Market in megawatt-hours for that Operating Day, and the scheduled megawatt-hours at the specified sink of an accepted Up-to Congestion Transaction; and (ii) scheduled energy sales in the Day-ahead Energy Market from within the PJM Region to load outside such region in megawatt-hours for that Operating Day, but not including its bilateral transactions that are Dynamic Transfers to load outside such area pursuant to Section 1.12, except to the extent PJM scheduled resources to provide Black Start service, Reactive Services or transfer interface control. The cost of Operating Reserves in the Day-ahead Energy Market for resources scheduled to provide Black Start service for the Operating Day which resources would not have otherwise been committed in the day-ahead security constrained dispatch shall be allocated by ratio share of the monthly transmission use of each Network Customer or Transmission Customer serving Zone Load or Non-Zone Load, as determined in accordance with the formulas contained in Schedule 6A of the PJM Tariff. The cost of Operating Reserves in the Day-ahead Energy Market for resources scheduled to provide Reactive Services or transfer interface control because they are known or expected to be needed to maintain system reliability in a Zone during the Operating Day and would not have otherwise been committed in the day-ahead security constrained dispatch shall be allocated and charged to each Market Participant in proportion to the sum of its real-time deliveries of energy to load (net of operating Behind The Meter Generation) in such Zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such Zone.

(e) At the end of each Operating Day, the following determination shall be made for each synchronized pool-scheduled resource of each Market Seller that operates as requested by the Office of the Interconnection. For each calendar day, pool-scheduled resources in the Real-time Energy Market shall be made whole for each of the following Segments: 1) the greater of their day-ahead schedules *and* minimum run time *specified at the time of commitment* (minimum down time *specified at the time of commitment* for Demand Resources); and 2) any block of *Real-time Settlement Intervals* the resource operates at PJM's direction in excess of the greater of its day-ahead schedule *and* minimum run time *specified at the time of commitment* (minimum down time *specified at the time of commitment* for Demand Resources). For each calendar day, and for each synchronized start of a generation resource or PJM-dispatched economic load reduction, there will be a maximum of two Segments for each resource. Segment 1 will be the greater of the day-ahead schedule and minimum run time *specified at the time of commitment* (minimum down time *specified at the time of commitment* for Demand Resources) and Segment 2 will include the remainder of the contiguous *Real-time Settlement Intervals* when the resource is operating at the direction of the Office of the Interconnection, provided that a segment is limited to the Operating Day in which it commenced and cannot include any part of the following Operating Day.

A Generation Capacity Resource that operates outside of its unit-specific parameters will not receive Operating Reserve Credits nor be made whole for such operation when not dispatched by the Office of the Interconnection, unless the Market Seller of the Generation Capacity Resource can justify to the Office of the Interconnection that operation outside of such unit-specific parameters was the result of an actual constraint. Such Market Seller shall provide to the Market Monitoring Unit and the Office of the Interconnection its request to receive Operating Reserve Credits and/or to be made whole for such operation, along with documentation explaining in detail the reasons for operating its resource outside of its unit-specific parameters, within thirty calendar days following the issuance of billing statement for the Operating Day. The Market Seller shall also respond to additional requests for information from the Market Monitoring Unit and the Office of the Interconnection. The Market Monitoring Unit shall evaluate such request for compensation and provide its determination of whether there was an exercise of market power to the Office of the Interconnection by no later than twenty-five calendar days after receiving the Market Seller's request for compensation. The Office of the Interconnection shall make its determination whether the Market Seller justified that it is entitled to receive Operating Reserve Credits and/or be made whole for such operation of its resource for the day(s) in question, by no later than thirty calendar days after receiving the Market Seller's request for compensation.

Credits received pursuant to this section shall be equal to the positive difference between a resource's Total Operating Reserve Offer, and the total value of the resource's energy for hours in the Day-ahead Energy Market that correspond to five-minute intervals in which the resource is operated in real-time pursuant to the Office of the Interconnection's direction, plus any credit or change for quantity deviations, at PJM dispatch direction (excluding quantity deviations caused by an increase in the Market Seller's Real-time Offer), from the Day-ahead Energy Market during the Operating Day at the real-time LMP(s) applicable to the relevant generation bus in the Real-time Energy Market. The foregoing notwithstanding, credits for segment 2 shall exclude start up (shutdown costs for Demand Resources) costs for generation resources.

Except as provided in Section 3.2.3(m), if the total offered price exceeds the total value, the difference less any credit as determined pursuant to Section 3.2.3(b), and less any amounts credited for Synchronized Reserve in excess of the Synchronized Reserve offer plus the resource's opportunity cost, and less any amounts credited for Non-Synchronized Reserve in excess of the Non-Synchronized Reserve offer plus the resource's opportunity cost, and less any amounts credited for providing Reactive Services as specified in Section 3.2.3B, and less any amounts for Day-ahead Scheduling Reserve in excess of the Day-ahead Scheduling Reserve offer plus the resource's opportunity cost, shall be credited to the Market Seller.

Synchronized Reserve, Non-Synchronized Reserve, and *Real-time Settlement Interval share of the* Day-ahead Scheduling Reserve credits applied against Operating Reserve credits pursuant to this section shall be netted against the Operating Reserve credits earned in the corresponding *Real-time Settlement Interval*(s) in which the Synchronized Reserve, Non-Synchronized Reserve, and Day-ahead Scheduling Reserve credits accrued, provided that for condensing combustion turbines, Synchronized Reserve credits will be netted against the total Operating Reserve credits accrued during each *Real-time Settlement Interval* the unit operates in condensing and generation mode.

(f) A Market Seller of a unit not defined in subsection (f-1), (f-2), or (f-4) hereof (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited *for each Real-time Settlement Interval* in an amount equal to the product of (A) the deviation of the generating unit's output necessary to follow the Office of the Interconnection's signals and the generating unit's expected output level if it had been dispatched in economic merit order, times (B) the Locational Marginal Price at the generation bus for the generating unit, minus (C) the Total Lost Opportunity Cost Offer, provided that the resulting outcome is greater than $0.00. This equation is represented as (A*B) - C.

(f-1) With the exception of Market Sellers of Flexible Resources that submit a Real-time Offer greater than their resource's Committed Offer in the Day-ahead Energy Market, a Market Seller of a Flexible Resource shall be compensated for lost opportunity cost, and shall be limited to the lesser of the unit's Economic Maximum or the unit's Generation Resource Maximum Output, if either of the following conditions occur:

(i) if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as directed by the PJM dispatcher), then the Market Seller shall be credited in a manner consistent with that described in section 3.2.3 (f).

(ii) *If the unit* is scheduled to produce energy in the Day-ahead Energy Market *for a Day-ahead Settlement Interval,* but the unit is not called on by the Office of the Interconnection and does not operate in *the corresponding Real-time Settlement Interval(s)*, then the Market Seller shall be credited in an amount equal to the higher of:

1) the product of (A) the amount of megawatts committed in the Day-ahead Energy Market for the generating unit, and (B) the Real-time Price at the generation bus for the generating unit, minus the sum of (C) the Total Lost Opportunity Cost Offer plus No-load Costs, plus (D) the Start-up Cost, divided by the *Real-time Settlement Intervals* committed for each set of contiguous hours for which the unit was scheduled in Day-ahead Energy Market. This equation is represented as (A*B) - (C+D). The startup cost, (D), shall be excluded from this calculation if the unit operates in real time following the Office of the Interconnection's direction during any portion of the set of contiguous hours for which the unit was scheduled in Day-ahead Energy Market, or

2) the Real-time Price at the unit's bus minus the Day-ahead Price at the unit's bus, multiplied by the number of megawatts committed in the Day-ahead Energy Market for the generating unit.

Market Sellers of Flexible Resources that submit a Real-time Offer greater than their resource's Committed Offer in the Day-ahead Energy Market shall not be eligible to receive compensation for lost opportunity costs under any applicable provisions of Schedule 1 of this Agreement.

(f-2) A Market Seller of a hydroelectric resource that is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), the output of which is altered at the request of the Office of the Interconnection from the schedule submitted by the owner, due to a transmission constraint or other reliability issue, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(f-3) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for opportunity cost associated with following PJM dispatch instructions and reducing or suspending a unit's output due to a transmission constraint or other reliability issue, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of opportunity cost compensation, the Office of the Interconnection shall invoice the Market Seller accordingly. If the Market Monitoring Unit disagrees with the modified amount of opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(f-4) A Market Seller *of a* wind generating unit that is pool-scheduled or self-scheduled, has SCADA capability to transmit and receive instructions from the Office of the Interconnection, has provided data and established processes to follow PJM basepoints pursuant to the requirements for wind generating units as further detailed in this Agreement, the Tariff and the PJM Manuals, and which is operating as requested by the Office of the Interconnection, the output of which is reduced or suspended at the request of the Office of the Interconnection due to a transmission constraint or other reliability issue, and for which the , real-time LMP at the unit's bus is higher than the unit's offer corresponding to the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall be credited *for each Real-time Settlement Interval* in an amount equal to the product of (A) the deviation of the generating unit's output necessary to follow the Office of the Interconnection's signals and the generating unit's expected output level if it had been dispatched in economic merit order, times (B) the Real-time Price at the generation bus for the generating unit, minus (C) the Total Lost Opportunity Cost Offer, provided that the resulting outcome is greater than $0.00. This equation is represented as (A*B) - C.

(g) The sum of the foregoing credits, plus any cancellation fees paid in accordance with Section 1.10.2(d), such cancellation fees to be applied to the Operating Day for which the unit was scheduled, plus any shortfalls paid pursuant to the Market Settlement provision of the real-time Economic Load Response Program, less any payments received from another Control Area for Operating Reserves shall be the cost of Operating Reserves for the Real-time Energy Market in each Operating Day.

(h) The cost of Operating Reserves for the Real-time Energy Market for each Operating Day, except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, shall be allocated and charged to each Market Participant *based on their daily total of hourly deviations determined in accordance with the following equation:*

$\sum_h (A + B + C)$

Where:

h = the hours in the applicable Operating Day;

A = For each Real-Time Settlement Interval in an hour, the sum of the absolute value of the withdrawal deviations (in MW) between the quantities scheduled in the Day-ahead Energy Market and the Market Participant's energy withdrawals (net of operating Behind The Meter Generation) in the Real-Time Energy Market, except as noted in subsection (h)(ii) below and in the PJM *Manuals divided by the number of Real-time Settlement Intervals for that hour. The summation of each Real-time Settlement Interval's withdrawal deviation in an hour will be the Market Participant's total hourly withdrawal deviations. Market Participant bilateral transactions that are Dynamic Transfers to load outside the PJM Region pursuant to section 1.12 of this Schedule are not included in the determination of withdrawal deviations*;

B = For each Real-Time Settlement Interval in an hour, the sum of the absolute value of generation deviations (*in MW and* not including deviations in Behind The Meter Generation) *as determined in subsection (o) divided by the number of Real-Time Settlement Intervals for that hour;*

C = For each Real-Time Settlement Interval in an hour, the sum of the absolute value of the injection deviations (in MW) between the quantities scheduled in the Day-ahead Energy Market and the Market Participant's energy injections in the Real-Time Energy Market divided by the number of Real-time Settlement Intervals for that hour. The summation of the injection deviations for each Real-time Settlement Interval in an hour will be the Market Participant's total hourly injection deviations. The determination of injection deviations does not include generation resources.

The Revenue Data for Settlements determined for each Real-time Settlement Interval in accordance with section 3.1A of this Schedule shall be used in determining the real-time *withdrawal deviations, generation deviations and injection deviations used to calculate Operating Reserve under this subsection (e).*

The costs associated with scheduling of units for Black Start service or testing of Black Start Units shall be allocated by ratio share of the monthly transmission use of each Network Customer or Transmission Customer serving Zone Load or Non-Zone Load, as determined in accordance with the formulas contained in Schedule 6A of the PJM Tariff.

Notwithstanding section (h)(1) above, as more fully set forth in the PJM Manuals, load deviations from the Day-ahead Energy Market shall not be assessed Operating Reserves charges to the extent attributable to reductions in the load of Price Responsive Demand that is in response to an increase in Locational Marginal Price from the Day-ahead Energy Market to the Real-time Energy Market and that is in accordance with a properly submitted PRD Curve.

Deviations that occur within a single Zone shall be associated with the Eastern or Western Region, as defined in Section 3.2.3(q) of this Schedule, and shall be subject to the regional balancing Operating Reserve rate determined in accordance with Section 3.2.3(q). Deviations at a hub shall be associated with the Eastern or Western Region if all the buses that define the hub are located in the region. Deviations at an Interface Pricing Point shall be associated with whichever region, the Eastern or Western Region, with which the majority of the buses that define that Interface Pricing Point are most closely electrically associated. If deviations at interfaces and hubs are associated with the Eastern or Western region, they shall be subject to the regional balancing Operating Reserve rate. Demand and supply deviations shall be based on total activity in a Zone, including all aggregates and hubs defined by buses that are wholly contained within the same Zone.

The foregoing notwithstanding, netting deviations shall be allowed *for each Real-time Settlement Interval* in accordance with the following provisions:

(i) Generation resources with multiple units located at a single bus shall be able to offset deviations in accordance with the PJM Manuals to determine the net deviation MW at the relevant bus.

(ii) Demand deviations will be assessed by comparing all day-ahead demand transactions at a single transmission zone, hub, or interface against the real-time demand transactions at that same transmission zone, hub, or interface; except that the positive values of demand deviations, as set forth in the PJM Manuals, will not be assessed Operating Reserve charges in the event of a Primary Reserve or Synchronized Reserve shortage in real-time or where PJM initiates the request for emergency load reductions in real-time in order to avoid a Primary Reserve or Synchronized Reserve shortage. The scheduled megawatt-hour withdrawal at the specified sink for an accepted Decrement Bid or Up-to Congestion Transaction are included in the determination of demand deviations. Bilateral transactions inside the PJM Region, as defined in section 1.7.10 of this Schedule, will not be included in the determination of demand deviations.

(iii) Supply deviations will be assessed by comparing all day-ahead transactions at a single transmission zone, hub, or interface against the real-time transactions at that same transmission zone, hub, or interface. The scheduled megawatt-hour injection at the specified source for an accepted Increment Offer or Up-to Congestion Transaction are included in the determination of supply deviations. Bilateral transactions inside the PJM Region, as defined in section 1.7.10 of this Schedule, will not be included in the determination of supply deviations.

(i) At the end of each Operating Day, Market Sellers shall be credited on the basis of their offered prices for synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, as well as the credits calculated as specified in Section 3.2.3(b) for those generators committed solely for the purpose of providing synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, at the request of the Office of the Interconnection.

(j) The sum of the foregoing credits as specified in Section 3.2.3(i) shall be the cost of Operating Reserves for synchronous condensing for the PJM Region for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-contingency operation for the Operating Day and shall be separately determined for the PJM Region.

(k) The cost of Operating Reserves for synchronous condensing for purposes other than providing Synchronized Reserve or Reactive Services, or in association with post-contingency operation for each Operating Day shall be allocated and charged to each Market Participant in proportion to the sum of its (i) deliveries of energy to load (net of operating Behind The Meter Generation, but not to be less than zero) in the PJM Region, served under Network Transmission Service, in megawatt-hours during that Operating Day; and (ii) deliveries of energy sales from within the PJM Region to load outside such region in megawatt-hours during that Operating Day, but not including its bilateral transactions that are Dynamic Transfers to load outside the PJM Region pursuant to Section 1.12, as compared to the sum of all such deliveries for all Market Participants.

(l) For any Operating Day in either, as applicable, the Day-ahead Energy Market or the Real-time Energy Market for which, for all or any part of such Operating Day, the Office of the Interconnection: (i) declares a Maximum Generation Emergency; (ii) issues an alert that a Maximum Generation Emergency may be declared ("Maximum Generation Emergency Alert"); or (iii) schedules units based on the anticipation of a Maximum Generation Emergency or a Maximum Generation Emergency Alert, the Operating Reserves credit otherwise provided by Section 3.2.3.(b) or Section 3.2.3(e) in connection with market-based offers shall be limited as provided in subsections (n) or (m), respectively. The Office of the Interconnection shall provide timely notice on its internet site of the commencement and termination of any of the actions described in subsection (i), (ii), or (iii) of this subsection (l) (collectively referred to as "MaxGen Conditions"). Following the posting of notice of the commencement of a MaxGen Condition, a Market Seller may elect to submit a cost-based offer in accordance with Schedule 2 of the Operating Agreement, in which case subsections (m) and (n) shall not apply to such offer; provided, however, that such offer must be submitted in accordance with the deadlines in Section 1.10 for the submission of offers in the Day-ahead Energy Market or Real-time Energy Market, as applicable. Submission of a cost-based offer under such conditions shall not be precluded by Section 1.9.7(b); provided, however, that the Market Seller must return to compliance with

Section 1.9.7(b) when it submits its bid for the first Operating Day after termination of the MaxGen Condition.

(m) For the Real-time Energy Market, if the Effective Offer Price (as defined below) for a market-based offer is greater than $1,000/MWh and greater than the Market Seller's lowest available and applicable cost-based offer, the Market Seller shall not receive any credit for Operating Reserves. For purposes of this subsection (m), the Effective Offer Price shall be the amount that, absent subsections (l) and (m), would have been credited for Operating Reserves for such Operating Day pursuant to Section 3.2.3(e) plus the Real-time Energy Market revenues for the *Real-time Settlement Intervals* that the offer is economic divided by the megawatt hours of energy provided during the *Real-time Settlement Intervals* that the offer is economic. The *Real-time Settlement Intervals* that the offer is economic shall be: (i) the *Real-time Settlement Intervals* that the offer price for energy is less than or equal to the Real-time Price for the relevant generation bus, (ii) the *Real-time Settlement Intervals* in which the offer for energy is greater than Locational Marginal Price and the unit is operated at the direction of the Office of the Interconnection that are in addition to any *Real-time Settlement Intervals* required due to the minimum run time or other operating constraint of the unit, and (iii) for any unit with a minimum run time of one hour or less and with more than one start available per day, any hours the unit operated at the direction of the Office of the Interconnection.

(n) For the Day-ahead Energy Market, if notice of a MaxGen Condition is provided prior to 10:30 a.m. on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price for a market-based offer is greater than $1,000/MWh and greater than the Market Seller's lowest available and applicable cost-based offer, the Market Seller shall not receive any credit for Operating Reserves. If notice of a MaxGen Condition is provided after 10:30 a.m. on the day before the Operating Day for which transactions are being scheduled and the Effective Offer Price is greater than $1,000/MWh, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. If the Effective Offer Price is less than or equal to $1,000/MWh, regardless of when notice of a MaxGen Condition is provided, the Market Seller shall receive credit for Operating Reserves determined in accordance with Section 3.2.3(b), subject to the limit on total compensation stated below. For purposes of this subsection (n), the Effective Offer Price shall be the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day divided by the megawatt hours of energy offered during the Specified Hours, plus the offer for energy during such hours. The Specified Hours shall be the lesser of: (1) the minimum run hours stated by the Market Seller in its Offer Data; and (2) either (i) for steam-electric generating units and for combined-cycle units when such units are operating in combined-cycle mode, the six consecutive hours of highest Day-ahead Price during such Operating Day when such units are running or (ii) for combustion turbine units and for combined-cycle units when such units are operating in combustion turbine mode, the two consecutive hours of highest Day-ahead Price during such Operating Day when such units are running. Notwithstanding any other provision in this subsection, the total compensation to a Market Seller on any Operating Day that includes a MaxGen Condition shall not exceed $1,000/MWh during the Specified Hours, where such total compensation in each such hour is defined as the amount that, absent subsections (l) and (n), would have been credited for Operating Reserves for such Operating Day pursuant to Section 3.2.3(b) divided by the

Specified Hours, plus the Day-ahead Price for such hour, and no Operating Reserves payments shall be made for any other hour of such Operating Day. If a unit operates in real time at the direction of the Office of the Interconnection consistently with its day-ahead clearing, then subsection (m) does not apply.

(o) Dispatchable pool-scheduled generation resources and dispatchable self-scheduled generation resources that follow dispatch shall not be assessed balancing Operating Reserve deviations. Pool-scheduled generation resources and dispatchable self-scheduled generation resources that do not follow dispatch shall be assessed balancing Operating Reserve deviations in accordance with the calculations described below and in the PJM Manuals.

The Office of the Interconnection shall calculate a ramp-limited desired MW value for generation resources where the economic minimum and economic maximum are at least as far apart in real-time as they are in day-ahead according to the following parameters:

(i) real-time economic minimum <= 105% of day-ahead economic minimum or day-ahead economic minimum plus 5 MW, whichever is greater.

(ii) real-time economic maximum >= 95% day-ahead economic maximum or day-ahead economic maximum minus 5 MW, whichever is lower.

The ramp-limited desired MW value for a generation resource shall be equal to:

$$\mathbf{Ramp\_Request_t} = \mathbf{(UDStarget_{t-1} - AOutput_{t-1})} / \mathbf{(UDSLAtime_{t-1})}$$

$$\mathbf{RL\_Desired_t} = \mathbf{AOutput_{t-1}} + \left(\mathbf{Ramp\_Request_t * Case\_Eff\_time_{t-1}}\right)$$

where:

1. UDStarget = UDS basepoint for the previous UDS case
2. AOutput = Unit’s output at case solution time
3. UDSLAtime = UDS look ahead time
4. Case_Eff_time = Time between base point changes
5. RL_Desired = Ramp-limited desired MW

To determine if a generation resource is following dispatch the Office of the Interconnection shall determine the unit’s MW off dispatch and % off dispatch by using the lesser of the difference between the actual output and the UDS Basepoint or the actual output and ramp-limited desired MW value *for each Real-time Settlement Interval.* If the UDS Basepoint and the ramp-limited desired MW for the resource are unavailable, the Office of the Interconnection will determine the unit’s MW off dispatch and % off dispatch by calculating the lesser of the difference between the actual output and the UDS LMP Desired *MW for each Real-time Settlement Interval*.

A pool-scheduled or dispatchable self-scheduled resource is considered to be following dispatch if its actual output is between its ramp-limited desired MW value and UDS Basepoint, or if its % off dispatch is <= 10, or its Real-time *Settlement Interval* MWh is within 5% of the *Real-time Settlement Interval* ramp-limited desired MW. A self-scheduled generator must also be dispatched above economic minimum. The degree of deviations for resources that are not following dispatch shall be determined *for each Real-time Settlement Interval* in accordance with the following provisions:

- A dispatchable self-scheduled resource that is not dispatched above economic minimum shall be assessed balancing Operating Reserve deviations according to the following formula: Real-time *Settlement Interval* MWh – Day-Ahead MWh.

- A resource that is dispatchable day-ahead but is Fixed Gen in real-time shall be assessed balancing Operating Reserve deviations according to the following formula: Real-time *Settlement Interval* MWh – UDS LMP Desired MW.

- Pool-scheduled generators that are not following dispatch shall be assessed balancing Operating Reserve deviations according to the following formula: Real-time *Settlement Interval* MWh –Ramp-Limited Desired MW.

- If a resource's real-time economic minimum is greater than its day-ahead economic minimum by 5% or 5 MW, whichever is greater, or its real-time economic maximum is less than its Day Ahead economic maximum by 5% or 5 MW, whichever is lower, and UDS LMP Desired MWh for the *Real-time Settlement Interval* is either below the real time economic minimum or above the real time economic maximum, then balancing Operating Reserve deviations for the resource shall be assessed according to the following formula: Real time *Settlement Interval* MWh – UDS LMP Desired MWh.

- If a resource is not following dispatch and its % Off Dispatch is <= 20%, balancing Operating Reserve deviations shall be assessed according to the following formula: Real-time *Settlement Interval* MWh – Ramp-Limited Desired MW. If deviation value is within 5% of Ramp-Limited Desired MW, balancing Operating Reserve deviations shall not be assessed.

- If a resource is not following dispatch and its % off Dispatch is > 20%, balancing Operating Reserve deviations shall be assessed according to the following formula: Real time *Settlement Interval* MWh – UDS LMP Desired MWh.

- If a resource is not following dispatch, and the resource has tripped, for the *Real-time Settlement Interval* the resource tripped and the *Real-time Settlement Intervals* it remains offline throughout its day-ahead schedule balancing Operating Reserve deviations shall be assessed according to the following formula: Real time *Settlement Interval* MWh – Day-Ahead MWh.

- For resources that are not dispatchable in both the Day-Ahead and Real-time Energy Markets balancing Operating Reserve deviations shall be assessed according to the following formula: Real-time *Settlement Interval* MWh - Day-Ahead MWh.

If a resource has a sum of the absolute value of generator deviations for an hour that is less than 5 MWh, then the resource shall not be assessed balancing Operating Reserve deviations for that hour.

(o-1) Dispatchable economic load reduction resources that follow dispatch shall not be assessed balancing Operating Reserve deviations. Economic load reduction resources that do not follow dispatch shall be assessed balancing Operating Reserve deviations as described in this subsection and as further specified in the PJM Manuals.

The Desired MW quantity for such resources for each hour shall be the hourly integrated MW quantity to which the load reduction resource was dispatched for each hour (where the hourly integrated value is the average of the dispatched values as determined by the Office of the Interconnection for the resource for each hour).

If the actual reduction quantity for the load reduction resource for a given hour deviates by no more than 20% above or below the Desired MW quantity, then no balancing Operating Reserve deviation will accrue for that hour. If the actual reduction quantity for the load reduction resource for a given hour is outside the 20% bandwidth, the balancing Operating Reserve deviations will accrue for that hour in the amount of the absolute value of (Desired MW – actual reduction quantity). For those hours where the actual reduction quantity is within the 20% bandwidth specified above, the load reduction resource will be eligible to be made whole for the total value of its offer as defined in section 3.3A of this Appendix. Hours for which the actual reduction quantity is outside the 20% bandwidth will not be eligible for the make-whole payment. If at least one hour is not eligible for make-whole payment based on the 20% criteria, then the resource will also not be made whole for its shutdown cost.

(p) The Office of the Interconnection shall allocate the charges assessed pursuant to Section 3.2.3(h) of Schedule 1 of this Agreement except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, to real-time deviations from day-ahead schedules or real-time load share plus exports depending on whether the underlying balancing Operating Reserve credits are related to resources scheduled during the reliability analysis for an Operating Day, or during the actual Operating Day.

(i) For resources scheduled by the Office of the Interconnection during the reliability analysis for an Operating Day, the associated balancing Operating Reserve charges shall be allocated based on the reason the resource was scheduled according to the following provisions:

(A) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to operate in real-time to augment the physical resources committed in the Day-ahead

Energy Market to meet the forecasted real-time load plus the Operating Reserve requirement, the associated balancing Operating Reserve charges shall be allocated to real-time deviations from day-ahead schedules.

(B) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource was committed to maintain system reliability, the associated balancing Operating Reserve charges shall be allocated according to ratio share of real time load plus export transactions.

(C) If the Office of the Interconnection determines during the reliability analysis for an Operating Day that a resource with a day-ahead schedule is required to deviate from that schedule to provide balancing Operating Reserves, the associated balancing Operating Reserve charges shall be allocated pursuant to (A) or (B) above.

(ii) For resources scheduled during an Operating Day, the associated balancing Operating Reserve charges shall be allocated according to the following provisions:

(A) If the Office of the Interconnection directs a resource to operate during an Operating Day to provide balancing Operating Reserves, the associated balancing Operating Reserve charges shall be allocated according to ratio share of load plus exports. The foregoing notwithstanding, charges will be assessed pursuant to this section only if the LMP at the resource's bus does not meet or exceed the applicable offer of the resource for at least four-5-minute intervals during one or more discrete clock hours during each period the resource operated and produced MWs during the relevant Operating Day. If a resource operated and produced MWs for less than four 5-minute intervals during one or more discrete clock hours during the relevant Operating Day, the charges for that resource during the hour it was operated less than four 5-minute intervals will be identified as being in the same category as identified for the Operating Reserves for the other discrete clock hours.

(B) If the Office of the Interconnection directs a resource not covered by Section 3.2.3(h)(ii)(A) of Schedule 1 of this Agreement to operate in real-time during an Operating Day, the associated balancing Operating Reserve charges shall be allocated according to real-time deviations from day-ahead schedules.

(q) The Office of the Interconnection shall determine regional balancing Operating Reserve rates for the Western and Eastern Regions of the PJM Region. For the purposes of this section, the Western Region shall be the AEP, APS, ComEd, Duquesne, Dayton, ATSI, DEOK, EKPC transmission Zones, and the Eastern Region shall be the AEC, BGE, Dominion, PENELEC, PEPCO, ME, PPL, JCPL, PECO, DPL, PSEG, RE transmission Zones. The regional balancing Operating Reserve rates shall be determined in accordance with the following provisions:

(i) The Office of the Interconnection shall calculate regional adder rates for the Eastern and Western Regions. Regional adder rates shall be equal to the total balancing Operating Reserve credits paid to generators for transmission constraints that occur on transmission system capacity equal to or less than 345kv. The regional adder rates shall be separated into reliability and deviation charges, which shall be allocated to real-time load or real-time deviations, respectively. Whether the underlying credits are designated as reliability or deviation charges shall be determined in accordance with Section 3.2.3(p).

(ii) The Office of the Interconnection shall calculate RTO balancing Operating Reserve rates. RTO balancing Operating Reserve rates shall be equal to balancing Operating Reserve credits except those associated with the scheduling of units for Black Start service or testing of Black Start Units as provided in Schedule 6A of the PJM Tariff, in excess of the regional adder rates calculated pursuant to Section 3.2.3(q)(i) of Schedule 1 of this Agreement. The RTO balancing Operating Reserve rates shall be separated into reliability and deviation charges, which shall be allocated to real-time load or real-time deviations, respectively. Whether the underlying credits are allocated as reliability or deviation charges shall be determined in accordance with Section 3.2.3(p).

(iii) Reliability and deviation regional balancing Operating Reserve rates shall be determined by summing the relevant RTO balancing Operating Reserve rates and regional adder rates.

(iv) If the Eastern and/or Western Regions do not have regional adder rates, the relevant regional balancing Operating Reserve rate shall be the reliability and/or deviation RTO balancing Operating Reserve rate.

(r) Market Sellers that incur incremental operating costs for a generation resource *that are either* greater than $*1*,000/MWh *as* determined in accordance with *the Market Seller's PJM-approved Fuel Cost Policy,* Schedule 2 of the Operating Agreement and PJM Manual 15, *but are not verified at the time of dispatch of the resource under section 6.4.3 of this Schedule, or greater than $2,000/MWh as determined in accordance with the Market Seller's PJM-approved Fuel Cost Policy, Schedule 2 of the Operating Agreement, and PJM Manual 15,* will be eligible to receive credit for Operating Reserves upon review of the Market Monitoring Unit and the Office of the Interconnection, and approval of the Office of the Interconnection. Market Sellers must submit to the Office of the Interconnection and the Market Monitoring Unit all relevant documentation demonstrating the calculation of costs greater than *$2,000/MWh, and costs greater than* $*1*,000/MWh *which were not verified at the time of dispatch of the resource under section 6.4.3 of this Schedule*. The Office of the Interconnection must approve any Operating Reserve credits paid to a Market Seller under this subsection (r).

3.2.3A Synchronized Reserve.

(a) Each Market Participant that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Synchronized Reserve equal to its pro rata share of Synchronized Reserve requirements for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market *Participant's* total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone or Reserve Sub-zone for the hour ("Synchronized Reserve Obligation"), less any amount obtained from condensers associated with provision of Reactive Services as described in section 3.2.3B(i) and any amount obtained from condensers associated with post-contingency operations, as described in section 3.2.3C(b). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. A Market Participant *with an* hourly Synchronized Reserve Obligation shall be charged *the pro rata share of the sum of the quantity of Synchronized Reserves provided in each Real-time Settlement Interval times the clearing price for all Real-time Settlement Intervals in the hour associated with that obligation.*

(b) A resource supplying Synchronized Reserve at the direction of the Office of the Interconnection, in excess of its hourly Synchronized Reserve Obligation, shall be credited as follows:

i) Credits for Synchronized Reserve provided by generation resources that are then subject to the energy dispatch signals and instructions of the Office of the Interconnection and that increase their current output or Demand Resources that reduce their load in response to a Synchronized Reserve Event ("Tier 1 Synchronized Reserve") shall be at the Synchronized Energy Premium Price*, as described in 3.2.3A (c),* with the exception of those *Real-time Settlement Intervals* in which the Non-Synchronized Reserve Market Clearing Price for the applicable Reserve Zone or Reserve Sub-zone is not equal to zero. During such hours, Tier 1 Synchronized Reserve resources shall be compensated at the Synchronized Reserve Market Clearing Price for the applicable Reserve Zone or Reserve Sub-zone for the lesser of the amount of Tier 1 Synchronized Reserve attributed to the resource as calculated by the Office of the Interconnection, or the actual amount of Tier 1 Synchronized Reserve provided should a Synchronized Reserve Event *occur in a Real-time Settlement Interval*.

ii) Credits for Synchronized Reserve provided by generation resources that are synchronized to the grid but, at the direction of the Office of the Interconnection, are operating at a point that deviates from the Office of the Interconnection energy dispatch signals and instructions ("Tier 2 Synchronized Reserve") shall be the higher of (i) the Synchronized Reserve Market Clearing Price or (ii) the sum of (A) the Synchronized Reserve offer, and (B) the specific opportunity cost of the generation resource supplying the increment of Synchronized Reserve, as determined by the Office of the Interconnection *to a Synchronized Reserve Event in a Real-time Settlement Interval* in accordance with procedures specified in the PJM Manuals.

iii) Credits for Synchronized Reserve provided by Demand Resources that are synchronized to the grid and accept the obligation to reduce load in response to a Synchronized Reserve Event *in a Real-time Settlement Interval* initiated by the Office of the Interconnection shall be the sum of (i) the higher of (A) the Synchronized Reserve offer or (B) the Synchronized Reserve Market Clearing Price and (ii) if a Synchronized Reserve Event is actually initiated by the Office of the Interconnection and the Demand Resource reduced its load in response to the event, the fixed costs associated with achieving the load reduction, as specified in the PJM Manuals.

(c) The Synchronized Reserve Energy Premium Price is an adder in an amount to be determined periodically by the Office of the Interconnection not less than fifty dollars and not to exceed one hundred dollars per megawatt hour.

(d) The Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each *Real-time Settlement Interval* of the Operating Day. The hourly Synchronized Reserve Market Clearing Price shall be calculated as the 5-minute clearing price. Each 5-minute clearing price shall be calculated as the marginal cost of serving the next increment of demand for Synchronized Reserve in each Reserve Zone or Reserve Sub-zone, inclusive of Synchronized Reserve offer prices and opportunity costs. When the Synchronized Reserve Requirement or Extended Synchronized Reserve Requirement in a Reserve Zone or Reserve Sub-zone cannot be met, the 5-minute clearing price shall be at least greater than or equal to the applicable Reserve Penalty Factor for the Reserve Zone or Reserve Sub-zone, but less than or equal to the sum of the Reserve Penalty Factors for the Synchronized Reserve Requirement and Primary Reserve Requirement for the Reserve Zone or Reserve Sub-zone. If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a Voltage Reduction Action as described in the PJM Manuals or a Manual Load Dump Action as described in the PJM Manuals, the 5-minute clearing price shall be the sum of the Reserve Penalty Factors for the Primary Reserve Requirement and the Synchronized Reserve Requirement for that Reserve Zone or Reserve Sub-zone.

The Reserve Penalty Factor for the Synchronized Reserve Requirement shall be $850/MWh.

The Reserve Penalty Factor for the Extended Synchronized Reserve Requirement shall be $300/MWh.

By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to prices exceeding $1,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Synchronized Reserve Penalty Factors are warranted for subsequent Delivery Year(s).

(e) *For each Real-time Settlement Interval and for* determining the 5-minute Synchronized Reserve clearing price, the estimated unit-specific opportunity cost for a generation resource *will be determined in accordance with the following equation:*

(A x B) + (C x D)

Where

A = *T*he Locational Marginal Price at the generation bus for the generation resource*;*

B = *T*he megawatts of energy used to provide Synchronized Reserve submitted as part of the Synchronized Reserve offer*;*

*C = T*he deviation of the set point of the generation resource that is expected to be required in order to provide Synchronized Reserve from the generation resource's expected output level if it had been dispatched in economic merit order*; and*

*D = T*he difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource.

The opportunity costs for a Demand Resource shall be zero.

(f) In determining the credit under subsection (b) to a resource selected to provide Tier 2 Synchronized Reserve and that actively follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each *Real-time Settlement Interval* that the Office of the Interconnection requires a generation resource to provide Tier 2 Synchronized Reserve and shall be *in accordance with the following equation:*

(A x B) + (C x D)

Where:

A = *T*he megawatts of energy used by the resource to provide Synchronized Reserve as submitted as part of the generation resource's Synchronized Reserve offer;

B = *T*he Locational Marginal Price at the generation bus of the generation resource;

*C = T*he deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order*; and*

D = *T*he difference between the Locational Marginal Price at the generation bus for the generation resource and the offer price for energy from the generation resource (at the megawatt level of the Synchronized Reserve set point for the generation resource) in the PJM Interchange Energy Market when the Locational Marginal Price at the generation bus is greater than the offer price for energy from the generation resource.

The opportunity costs for a Demand Resource shall be zero.

(g) Charges for Tier 1 Synchronized Reserve will be allocated in proportion to the amount of Tier 1 Synchronized Reserve applied to each Synchronized Reserve Obligation. In the event Tier 1 Synchronized Reserve is provided by a Market *Participant* in excess of that Market *Participant's* Synchronized Reserve Obligation, the Tier 1 Synchronized Reserve that is not utilized to fulfill the *Market Participant's* obligation will be allocated proportionately among all other Synchronized Reserve Obligations.

(h) Any amounts credited for Tier 2 Synchronized Reserve in a *Real-time Settlement Interval* in excess of the Synchronized Reserve Market Clearing Price in that *Real-time Settlement Interval* shall be allocated and charged to each Market Participant that does not meet its hourly Synchronized Reserve Obligation in proportion to its purchases of Synchronized Reserve in megawatt-hours during that hour.

(i) In the event the Office of the Interconnection needs to assign more Tier 2 Synchronized Reserve during a *Real-time Settlement Interval* than was estimated as needed at the time the Synchronized Reserve Market Clearing Price was calculated for that *Real-time Settlement Interval* due to a reduction in available Tier 1 Synchronized Reserve, the costs of the excess Tier 2 Synchronized Reserve shall be allocated and charged to those providers of Tier 1 Synchronized Reserve whose available Tier 1 Synchronized Reserve was reduced from the needed amount estimated during the Synchronized Reserve Market Clearing Price calculation, in proportion to the amount of the reduction in Tier 1 Synchronized Reserve availability.

(j) In the event a generation resource or Demand Resource that either has been assigned by the Office of the Interconnection or self-scheduled to provide Tier 2 Synchronized Reserve fails to provide the assigned or self-scheduled amount of Tier 2 Synchronized Reserve in response to a Synchronized Reserve Event, the resource will be credited for Tier 2 Synchronized Reserve capacity in the amount that actually responded for all *Real-time Settlement Intervals* the resource was assigned or self-scheduled Tier 2 Synchronized Reserve on the Operating Day during which the event occurred. The determination of the amount of Synchronized Reserve credited to a resource shall be on an individual resource basis, not on an aggregate basis.

The resource shall refund payments received for Tier 2 Synchronized Reserve it failed to provide. For purposes of determining the amount of the payments to be refunded by a Market Participant, the Office of the Interconnection shall calculate the shortfall of Tier 2 Synchronized Reserve on an individual resource basis unless the Market Participant had multiple resources that were assigned or self-scheduled to provide Tier 2 Synchronized Reserve, in which case the shortfall will be determined on an aggregate basis. For performance determined on an aggregate basis, the response of any resource that provided more Tier 2 Synchronized Reserve than it was assigned or self-scheduled to provide will be used to offset the performance of other resources that provided less Tier 2 Synchronized Reserve than they were assigned or self-scheduled to provide during a Synchronized Reserve Event, as calculated in the PJM Manuals. The determination of a Market Participant's aggregate response shall not be taken into consideration in the determination of the amount of Tier 2 Synchronized Reserve credited to each individual resource.

The amount refunded shall be determined by multiplying the Synchronized Reserve Market Clearing Price by the amount of the shortfall of Tier 2 Synchronized Reserve, measured in megawatts, for all *intervals* the resource was assigned or self-scheduled to provide Tier 2 Synchronized Reserve for a period of time immediately preceding the Synchronized Reserve Event equal to the lesser of the average number of days between Synchronized Reserve Events, or the number of days since the resource last failed to provide the amount of Tier 2 Synchronized Reserve it was assigned or self-scheduled to provide in response to a Synchronized Reserve Event. The average number of days between Synchronized Reserve Events for purposes of this calculation shall be determined by an annual review of the twenty-four month period ending October 31 of the calendar year in which the review is performed, and shall be rounded down to a whole day value. The Office of the Interconnection shall report the results of its annual review to stakeholders by no later than December 31, and the average number of days between Synchronized Reserve Events shall be effective as of the following January 1. The refunded charges shall be allocated as credits to Market Participants based on its pro rata share of the Synchronized Reserve Obligation megawatts less any Tier 1 Synchronized Reserve applied to its Synchronized Reserve Obligation in the hour(s) of the Synchronized Reserve Event for the Reserve Sub-zone or Reserve Zone, except that Market Participants that incur a refund obligation and also have an applicable Synchronized Reserve Obligation during the hour(s) of the Synchronized Reserve Event shall not be included in the allocation of such refund credits. If the event spans multiple hours, the refund credits will be prorated hourly based on the duration of the event within each clock hour.

(k) The magnitude of response to a Synchronized Reserve Event by a generation resource or a Demand Resource, except for Batch Load Demand Resources covered by section 3.2.3A(l), is the difference between the generation resource’s output or the Demand Resource’s consumption at the start of the event and its output or consumption 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output or Demand Resource consumption at the start of the event is defined as the lowest telemetered generator resource output or greatest Demand Resource consumption between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output or a Demand Resource's consumption 10 minutes after the event is defined as the greatest generator resource output or lowest Demand Resource consumption achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter. The response actually credited to a Demand Resource will be reduced by the amount the megawatt consumption of the Demand Resource exceeds the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

(l) The magnitude of response by a Batch Load Demand Resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the start of a Synchronized Reserve Event shall be the difference between (i) the Batch Load Demand Resource’s consumption at the end of the Synchronized Reserve Event and (ii) the Batch Load Demand Resource’s consumption during the minute within the ten minutes after the end of the Synchronized Reserve Event in which the Batch Load Demand Resource’s consumption was highest and for which its consumption in all subsequent minutes within the ten minutes was not less than fifty percent of the consumption in such minute; provided that, the

magnitude of the response shall be zero if, when the Synchronized Reserve Event commences, the scheduled off-cycle stage of the production cycle is greater than ten minutes. .

3.2.3A.001 Non-Synchronized Reserve.

(a) Each Market Participant that is a Load Serving Entity that is not part of an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have an obligation for hourly Non-Synchronized Reserve equal to its pro rata share of Non-Synchronized Reserve assigned for the hour for each Reserve Zone and Reserve Sub-zone of the PJM Region, based on the Market *Participant's* total load (net of operating Behind The Meter Generation, but not to be less than zero) in such Reserve Zone and Reserve Sub-zone for the hour ("Non-Synchronized Reserve Obligation"). Those entities that participate in an agreement to share reserves with external entities subject to the requirements in BAL-002 shall have their reserve obligations determined based on the stipulations in such agreement. A Market Participant *with an* hourly Non-Synchronized Reserve Obligation shall be charged *the pro rata share of the sum of the quantity of Non-Synchronized Reserves provided in each Real-time Settlement Interval times the clearing price for all Real-time Settlement Intervals in the hour associated with that obligation.*

(b) Credits for Non-Synchronized Reserve provided by generation resources that are not operating for energy at the direction of the Office of the Interconnection specifically for the purpose of providing Non-Synchronized Reserve shall be the higher of (i) the Non-Synchronized Reserve Market Clearing Price or (ii) the specific opportunity cost of the generation resource supplying the increment of Non-Synchronized Reserve, as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals.

(c) The Non-Synchronized Reserve Market Clearing Price shall be determined for each Reserve Zone and Reserve Sub-zone by the Office of the Interconnection for each *Real-time Settlement Interval* of the Operating Day. The Non-Synchronized Reserve Market Clearing Price shall be calculated as the 5-minute clearing price. Each 5-minute clearing price shall be calculated as the marginal cost of procuring sufficient Non-Synchronized Reserves and/or Synchronized Reserves in each Reserve Zone or Reserve Sub-zone inclusive of opportunity costs associated with meeting the Primary Reserve Requirement or Extended Primary Reserve Requirement. When the Primary Reserve Requirement or Extended Primary Reserve Requirement in a Reserve Zone or Reserve Sub-zone cannot be met at a price less than or equal to the applicable Reserve Penalty Factor, the 5-minute clearing price for Non-Synchronized Reserve shall be at least greater than or equal to the applicable Reserve Penalty Factor for the Reserve Zone or Reserve Sub-zone, but less than or equal to the Reserve Penalty Factor for the Primary Reserve Requirement for the Reserve Zone or Reserve Sub-zone. If the Office of the Interconnection has initiated in a Reserve Zone or Reserve Sub-zone either a *V*oltage *R*eduction *A*ction as described in the PJM Manuals or a *M*anual *L*oad *D*ump *A*ction as described in the PJM Manuals, the 5-minute clearing price shall be the Reserve Penalty Factor for the Primary Reserve Requirement for that Reserve Zone or Reserve Sub-zone.

The Reserve Penalty Factor for the Synchronized Reserve Requirement shall be $850/MWh.

The Reserve Penalty Factor for the Extended Primary Reserve Requirement shall be $300/MWh.

By no later than April 30 of each year, the Office of the Interconnection will analyze Market Participants' response to prices exceeding $1,000/MWh on an annual basis and will provide its analysis to PJM stakeholders. The Office of the Interconnection will also review this analysis to determine whether any changes to the Primary Reserve Penalty Factors are warranted for subsequent Delivery Year(s).

(d) *For each Real-time Settlement Interval and for* determining the 5-minute Non-Synchronized Reserve clearing price, the unit-specific opportunity cost for a generation resource that is not providing energy because they are providing Non-Synchronized Reserves *will be determined in accordance with the following equation:*

(A x B) – C

Where:
A = *T*he deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order;

B = *T*he Locational Marginal Price at the generation bus for the generation resource; *and*

C = *T*he applicable offer for energy from the generation resource in the PJM Interchange Energy Market.

(e) In determining the credit under subsection (b) to a resource selected to provide Non-Synchronized Reserve and that follows the Office of the Interconnection's signals and instructions, the unit-specific opportunity cost of a generation resource shall be determined for each *Real-time Settlement Interval* that the Office of the Interconnection requires a generation resource to provide Non- Synchronized Reserve and shall be *in accordance with the following equation:*

(A x B) – C

Where:
A = *T*he deviation of the generation resource's output necessary to follow the Office of the Interconnection's signals and instructions from the generation resource's expected output level if it had been dispatched in economic merit order;

B = *T*he Locational Marginal Price at the generation bus for the generation resource; *and*

C = *T*he applicable offer for energy from the generation resource in the PJM Interchange Energy Market.

(f) Any amounts credited for Non-Synchronized Reserve in a *Real-time Settlement Interval* in excess of the Non-Synchronized Reserve Market Clearing Price in that *Real-time Settlement Interval* shall be allocated and charged to each Market Participant that does not meet its hourly Non-Synchronized Reserve Obligation in proportion to its purchases of Non-Synchronized Reserve in megawatt-hours during that hour.

(g) The magnitude of response to a Non-Synchronized Reserve Event by a generation resource is the difference between the generation resource's output at the start of the event and its output 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, generation resource output at the start of the event is defined as the lowest telemetered generator resource output between one minute prior to and one minute following the start of the event. Similarly, a generation resource's output 10 minutes after the start of the event is defined as the greatest generator resource output achieved between 9 and 11 minutes after the start of the event. The response actually credited to a generation resource will be reduced by the amount the megawatt output of the generation resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

(h) In the event a generation resource that has been assigned by the Office of the Interconnection to provide Non-Synchronized Reserve fails to provide the assigned amount of Non-Synchronized Reserve in response to a Non-Synchronized Reserve Event, the resource will be credited for Non-Synchronized Reserve capacity in the amount that actually responded for the contiguous *Real-time Settlement Interval* the resource was assigned Non-Synchronized Reserve during which the event occurred.

3.2.3A.01 Day-ahead Scheduling Reserves.

(a) The Office of the Interconnection shall satisfy the Day-ahead Scheduling Reserves Requirement by procuring Day-ahead Scheduling Reserves in the Day-ahead Scheduling Reserves Market from Day-ahead Scheduling Reserves Resources, provided that Demand Resources shall be limited to providing the lesser of any limit established by the Reliability First Corporation or SERC, as applicable, or twenty-five percent of the total Day-ahead Scheduling Reserves Requirement. Day-ahead Scheduling Reserves Resources that clear in the Day-ahead Scheduling Reserves Market shall receive a Day-ahead Scheduling Reserves schedule from the Office of the Interconnection for the relevant Operating Day. PJMSettlement shall be the Counterparty to the purchases and sales of Day-ahead Scheduling Reserves in the PJM Interchange Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a self-schedule or self-supply of generation resources by a Market Buyer to satisfy its Day-ahead Scheduling Reserves Requirement.

(b) A Day-ahead Scheduling Reserves Resource that receives a Day-ahead Scheduling Reserves schedule pursuant to subsection (a) of this section shall be paid the hourly Day-ahead Scheduling Reserves Market clearing price for the cleared megawatt quantity of Day-ahead Scheduling Reserves in each hour of the schedule, subject to meeting the requirements of subsection (c) of this section.

(c) To be eligible for payment pursuant to subsection (b) of this section, Day-ahead Scheduling Reserves Resources shall comply with the following provisions:

(i) Generation resources with a start time greater than thirty minutes are required to be synchronized and operating at the direction of the Office of the Interconnection during the resource's Day-ahead Scheduling Reserves schedule and shall have a dispatchable range equal to or greater than the Day-ahead Scheduling Reserves schedule.

(ii) Generation resources and Demand Resources with start times or shut-down times, respectively, equal to or less than 30 minutes are required to respond to dispatch directives from the Office of the Interconnection during the resource's Day-ahead Scheduling Reserves schedule. To meet this requirement the resource shall be required to start or shut down within the specified notification time plus its start or shut down time, provided that such time shall be less than thirty minutes.

(iii) Demand Resources with a Day-ahead Scheduling Reserves schedule shall be credited based on the difference between the resource's MW consumption at the time the resource is directed by the Office of the Interconnection to reduce its load (starting MW usage) and the resource's MW consumption at the time when the Demand Resource is no longer dispatched by PJM (ending MW usage). For the purposes of this subsection, a resource's starting MW usage shall be the greatest telemetered consumption between one minute prior to and one minute following the issuance of a dispatch instruction from the Office of the Interconnection, and a resource's ending MW usage shall be the lowest consumption between one minute before and one minute after a dispatch instruction from the Office of the Interconnection that is no longer necessary to reduce.

(iv) Notwithstanding subsection (iii) above, the credit for a Batch Load Demand Resource that is at the stage in its production cycle when its energy consumption is less than the level of megawatts in its offer at the time the resource is directed by the Office of the Interconnection to reduce its load shall be the difference between (i) the "ending MW usage" (as defined above) and (ii) the Batch Load Demand Resource's consumption during the minute within the ten minutes after the time of the "ending MW usage" in which the Batch Load Demand Resource's consumption was highest and for which its consumption in all subsequent minutes within the ten minutes was not less than fifty percent of the consumption in such minute; provided that, the credit shall be zero if, at the time the resource is directed by the Office of the Interconnection to reduce its load, the scheduled off-cycle stage of the production cycle is greater than the timeframe for which the resource was dispatched by PJM.

Resources that do not comply with the provisions of this subsection (c) shall not be eligible to receive credits pursuant to subsection (b) of this section.

(d) The hourly credits paid to Day-ahead Scheduling Reserves Resources satisfying the Base Day-ahead Scheduling Reserves Requirement ("Base Day-ahead Scheduling Reserves credits") shall equal the ratio of the Base Day-ahead Scheduling Reserves Requirement to the Day-ahead Scheduling Reserves Requirement, multiplied by the total credits paid to Day-ahead Scheduling Reserves Resources, and are allocated as Base Day-ahead Scheduling Reserves charges per paragraph (i) below. The hourly credits paid to Day-ahead Scheduling Reserve Resources satisfying the Additional Day-ahead Scheduling Reserve Requirement ("Additional Day-ahead Scheduling Reserves credits") shall equal the ratio of the Additional Day-ahead Scheduling Reserves Requirement to the Day-ahead Scheduling Reserves Requirement, multiplied by the total credits paid to Day-ahead Scheduling Reserves Resources and are allocated as Additional Day-ahead Scheduling Reserves charges per paragraph (ii) below.

(i) A Market Participant's Base Day-ahead Scheduling Reserves charge is equal to the ratio of the Market Participant's hourly obligation to the total hourly obligation of all Market Participants in the PJM Region, multiplied by the Base Day-ahead Scheduling Reserves credits. The hourly obligation for each Market Participant is a megawatt representation of the portion of the Base Day-ahead Scheduling Reserves credits that the Market Participant is responsible for paying to PJM. The hourly obligation is equal to the Market Participant's load ratio share of the total megawatt volume of Base Day-ahead Scheduling Reserves resources (described below), based on the Market Participant's total hourly load (net of operating Behind The Meter Generation, but not to be less than zero) to the total hourly load of all Market Participants in the PJM Region. The total megawatt volume of Base Day-ahead Scheduling Reserves resources equals the ratio of the Base Day-ahead Scheduling Reserves Requirement to the Day-ahead Scheduling Reserves Requirement multiplied by the total volume of Day-ahead Scheduling Reserves megawatts paid pursuant to paragraph (c) of this section. A Market Participant's hourly Day-ahead Scheduling Reserves obligation can be further adjusted by any Day-ahead Scheduling Reserve bilateral transactions.

(ii) Additional Day-ahead Scheduling Reserves credits shall be charged hourly to Market Participants that are net purchasers in the Day-ahead Energy Market based on its positive demand difference ratio share. The positive demand difference for each Market Participant is the difference between its real-time load (net of operating Behind The Meter Generation, but not to be less than zero) and cleared Demand Bids in the Day-ahead Energy Market, net of cleared Increment Offers and cleared Decrement Bids in the Day-ahead Energy Market, when such value is positive. Net purchasers in the Day-ahead Energy Market are those Market Participants that have cleared Demand Bids plus cleared Decrement Bids in excess of its amount of cleared Increment Offers in the Day-ahead Energy Market. If there are no Market Participants with a positive demand difference, the Additional Day-ahead Scheduling Reserves credits are allocated according to paragraph (i) above.

(e) If the Day-ahead Scheduling Reserves Requirement is not satisfied through the operation of subsection (a) of this section, any additional Operating Reserves required to meet the requirement shall be scheduled by the Office of the Interconnection pursuant to Section 3.2.3 of Schedule 1 of this Agreement.

3.2.3B Reactive Services.

(a) A Market Seller providing Reactive Services at the direction of the Office of the Interconnection shall be credited as specified below for the operation of its resource. These provisions are intended to provide payments to generating units when the LMP dispatch algorithms would not result in the dispatch needed for the required reactive service. LMP will be used to compensate generators that are subject to redispatch for reactive transfer limits.

(b) At the end of each Operating Day, where the active energy output of a Market Seller's resource is reduced or suspended at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region, the Market Seller shall be credited according to Sections 3.2.3B(c) & 3.2.3B(d).

(c) A Market Seller providing Reactive Services from either a steam-electric generating unit or combined cycle unit operating in combined cycle mode, where such unit is pool-scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override) shall be compensated for lost opportunity cost by receiving a credit in an amount equal to the product of (A) the deviation of the generating unit's output necessary to follow the Office of the Interconnection's signals and the generating unit's expected output level if it had been dispatched in economic merit order, times (B) the Real-time Price at the generation bus for the generating unit, minus (C) the Total Lost Opportunity Cost Offer, provided that the resulting outcome is greater than $0.00. This equation is represented as (A*B) - C.

(d) A Market Seller providing Reactive Services from either a combustion turbine unit or combined cycle unit operating in simple cycle mode that is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), operated as requested by the Office of the Interconnection, shall be compensated for lost opportunity cost, limited to the lesser of the unit's Economic Maximum or the unit's Generation Resource Maximum Output, if the unit output is reduced at the direction of the Office of the Interconnection and the real time LMP at the unit's bus is higher than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection as directed by the PJM dispatcher, then the Market Seller shall be credited in a manner consistent with that described above in Section 3.2.3B(c) for a steam unit or a combined cycle unit operating in combined cycle mode.

(e) At the end of each Operating Day, where the active energy output of a Market Seller's unit is increased at the request of the Office of the Interconnection for the purpose of maintaining reactive reliability within the PJM Region and the offered price of the energy is above the real-time LMP at the unit's bus, the Market Seller shall be credited according to Section 3.2.3B(f).

(f) A Market Seller providing Reactive Services from either a steam-electric generating unit, combined cycle unit or combustion turbine unit, where such unit is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the real time LMP at the unit's bus is lower than the price offered by the Market Seller for energy from the unit at the level of output requested by the Office of the Interconnection (as indicated either by the desired MWs of output from the unit determined by PJM's unit dispatch system or as directed by the PJM dispatcher through a manual override), shall receive a credit hourly in an amount equal to {(AG - LMPDMW) x (UB - URTLMP)}where:

AG equals the actual output of the unit;

LMPDMW equals the level of output for the unit determined according to the point on the scheduled offer curve on which the unit was operating corresponding to the real time LMP at the unit's bus and adjusted for any Regulation or Tier 2 Synchronized Reserve assignments;

UB equals the unit offer for that unit for which output is increased, determined according to the lesser of the Final Offer or Committed Offer;

URTLMP equals the real time LMP at the unit's bus; and

where UB - URTLMP shall not be negative.

(g) A Market Seller providing Reactive Services from a hydroelectric resource where such resource is pool scheduled (or self-scheduled, if operating according to Section 1.10.3 (c) hereof), and where the output of such resource is altered from the schedule submitted by the Market Seller for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, shall be compensated for lost opportunity cost in the same manner as provided in sections 3.2.2(d) and 3.2.3A(f) and further detailed in the PJM Manuals.

(h) If a Market Seller believes that, due to specific pre-existing binding commitments to which it is a party, and that properly should be recognized for purposes of this section, the above calculations do not accurately compensate the Market Seller for lost opportunity cost associated with following the Office of the Interconnection's dispatch instructions to reduce or suspend a unit's output for the purpose of maintaining reactive reliability, then the Office of the Interconnection, the Market Monitoring Unit and the individual Market Seller will discuss a mutually acceptable, modified amount of such alternate lost opportunity cost compensation, taking into account the specific circumstances binding on the Market Seller. Following such discussion, if the Office of the Interconnection accepts a modified amount of alternate lost opportunity cost compensation, the Office of the Interconnection shall invoice the Market *Participant* accordingly. If the Market Monitoring Unit disagrees with the modified amount of alternate lost opportunity cost compensation, as accepted by the Office of the Interconnection, it will exercise its powers to inform the Commission staff of its concerns.

(i) The amount of Synchronized Reserve provided by generating units maintaining reactive reliability shall be counted as Synchronized Reserve satisfying the overall PJM Synchronized Reserve requirements. Operators of these generating units shall be notified of such provision, and to the extent a generating unit's operator indicates that the generating unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in Section 3.2.3A regarding provision of Tier 2 Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated to provide Reactive Services also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing for the purpose of maintaining reactive reliability at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the Synchronized Reserve Market Clearing Price for each *Real-time Settlement Interval* a generating unit provided synchronous condensing multiplied by the amount of Synchronized reserve provided by the synchronous condenser or (ii) the sum of (A) the generating unit's cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the product of MW energy usage for providing synchronous condensing multiplied by the real time LMP at the generating unit's bus, (C) the generating unit's startup-cost of providing synchronous condensing, and (D) the unit-specific lost opportunity cost of the generating resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated to provide Reactive Services was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generating unit's cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to subsection (l) below.

(j) A Market Seller's pool scheduled steam-electric generating unit or combined cycle unit operating in combined cycle mode, that is not committed to operate in the Day-ahead Market, but that is directed by the Office of the Interconnection to operate solely for the purpose of maintaining reactive reliability, at the request of the Office of the Interconnection, shall be credited in the amount of the unit's offered price for start-up and no-load fees. The unit also shall receive, if applicable, compensation in accordance with Sections 3.2.3B(e)-(f).

(k) The sum of the foregoing credits as specified in Sections 3.2.3B(b)-(j) shall be the cost of Reactive Services for the purpose of maintaining reactive reliability for the Operating Day and shall be separately determined for each transmission zone in the PJM Region based on whether the resource was dispatched for the purpose of maintaining reactive reliability in such transmission zone.

(l) The cost of Reactive Services for the purpose of maintaining reactive reliability in a transmission zone in the PJM Region for each Operating Day shall be allocated and charged to each Market Participant in proportion to its deliveries of energy to load (net of operating Behind The Meter Generation) in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

(m) Generating units receiving dispatch instructions from the Office of the Interconnection under the expectation of increased actual or reserve reactive shall inform the Office of the Interconnection dispatcher if the requested reactive capability is not achievable.

Should the operator of a unit receiving such instructions realize at any time during which said instruction is effective that the unit is not, or likely would not be able to, provide the requested amount of reactive support, the operator shall as soon as practicable inform the Office of the Interconnection dispatcher of the unit's inability, or expected inability, to provide the required reactive support, so that the associated dispatch instruction may be cancelled. PJM Performance Compliance personnel will audit operations after-the-fact to determine whether a unit that has altered its active power output at the request of the Office of the Interconnection has provided the actual reactive support or the reactive reserve capability requested by the Office of the Interconnection. PJM shall utilize data including, but not limited to, historical reactive performance and stated reactive capability curves in order to make this determination, and may withhold such compensation as described above if reactive support as requested by the Office of the Interconnection was not or could not have been provided.

3.2.3C Synchronous Condensing for Post-Contingency Operation.

(a) Under normal circumstances, PJM operates generation out of merit order to control contingency overloads when the flow on the monitored element for loss of the contingent element ("contingency flow") exceeds the long-term emergency rating for that facility, typically a 4-hour or 2-hour rating. At times however, and under certain, specific system conditions, PJM does not operate generation out of merit order for certain contingency overloads until the contingency flow on the monitored element exceeds the 30-minute rating for that facility ("post-contingency operation"). In conjunction with such operation, when the contingency flow on such element exceeds the long-term emergency rating, PJM operates synchronous condensers in the areas affected by such constraints, to the extent they are available, to provide greater certainty that such resources will be capable of producing energy in sufficient time to reduce the flow on the monitored element below the normal rating should such contingency occur.

(b) The amount of Synchronized Reserve provided by synchronous condensers associated with post-contingency operation shall be counted as Synchronized Reserve satisfying the PJM Synchronized Reserve requirements. Operators of these generation units shall be notified of such provision, and to the extent a generation unit's operator indicates that the generation unit is capable of providing Synchronized Reserve, shall be subject to the same requirements contained in Section 3.2.3A regarding provision of Tier 2 Synchronized Reserve. At the end of each Operating Day, to the extent a condenser operated in conjunction with post-contingency operation also provided Synchronized Reserve, a Market Seller shall be credited for providing synchronous condensing in conjunction with post-contingency operation at the request of the Office of the Interconnection, in an amount equal to the higher of (i) the Synchronized Reserve Market Clearing Price for each *applicable interval* a generation resource provided synchronous condensing multiplied by the amount of Synchronized Reserve provided by the synchronous condenser or (ii) the sum of (A) the generation resource's *applicable interval* cost to provide synchronous condensing, calculated in accordance with the PJM Manuals, (B) the *applicable interval* product of the megawatts of energy used to provide synchronous condensing multiplied by the real-time LMP at the generation bus of the generation resource, (C) the generation resource's start-up cost of providing synchronous condensing, and (D) the unit-specific lost opportunity cost of the generation resource supplying the increment of Synchronized Reserve as determined by the Office of the Interconnection in accordance with procedures specified in the PJM Manuals. To the extent a condenser operated in association with post-contingency constraint control was not also providing Synchronized Reserve, the Market Seller shall be credited only for the generation unit's cost to condense, as described in (ii) above. The total Synchronized Reserve Obligations of all Load Serving Entities under section 3.2.3A(a) in the zone where these condensers are located shall be reduced by the amount counted as satisfying the PJM Synchronized Reserve requirements. The Synchronized Reserve Obligation of each Load Serving Entity in the zone under section 3.2.3A(a) shall be reduced to the same extent that the costs of such condensers counted as Synchronized Reserve are allocated to such Load Serving Entity pursuant to subsection (d) below.

(c) The sum of the foregoing credits as specified in section 3.2.3C(b) shall be the cost of synchronous condensers associated with post-contingency operations for the Operating Day and shall be separately determined for each transmission zone in the PJM Region based on whether the resource was dispatched in association with post-contingency operation in such transmission zone.

(d) The cost of synchronous condensers associated with post-contingency operations in a transmission zone in the PJM Region for each Operating Day shall be allocated and charged to each Market Participant in proportion to its deliveries of energy to load (net of operating Behind The Meter Generation) in such transmission zone, served under Network Transmission Service, in megawatt-hours during that Operating Day, as compared to all such deliveries for all Market Participants in such transmission zone.

3.2.4 Transmission Congestion Charges.

Each Market Buyer shall be assessed Transmission Congestion Charges as specified in Section 5 of this Schedule.

3.2.5 Transmission Loss Charges.

Each Market Buyer shall be assessed Transmission Loss Charges as specified in Section 5 of this Schedule.

3.2.6 Emergency Energy.

(a) When the Office of the Interconnection has implemented Emergency procedures, resources offering Emergency energy are eligible to set real-time Locational Marginal Prices, capped at the energy offer cap plus the sum of the applicable Reserve Penalty Factors for the Synchronized Reserve Requirement and Primary Reserve Requirement, provided that the Emergency energy is needed to meet demand in the PJM Region.

(b) Market Participants shall be allocated a proportionate share of the net cost of Emergency energy purchased by the Office of the Interconnection. Such allocated share during each *applicable interval* of such Emergency energy purchase shall be in proportion to the amount of each Market Participant's real-time deviation from its net *withdrawals and injections* in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market sales. This deviation shall not include any reduction or suspension of output of pool scheduled resources requested by PJM to manage an Emergency within the PJM Region.

(c) Net revenues in excess of Real-time Prices attributable to sales of energy in connection with Emergencies to other Control Areas shall be credited to Market Participants during each *applicable interval* of such Emergency energy sale in proportion to the sum of (i) each Market Participant's real-time deviation from its net *withdrawals and injections* in the Day-ahead Energy Market, whenever that deviation increases the Market Participant's spot market purchases or decreases its spot market sales, and (ii) each Market Participant's energy sales from within the PJM Region to entities outside the PJM Region that have been curtailed by PJM.

(d) The net costs or net revenues associated with sales or purchases of energy in connection with a Minimum Generation Emergency in the PJM Region, or in another Control Area, shall be allocated during each *applicable interval* of such Emergency sale or purchase to each Market Participant in proportion to the amount of each Market Participant's real-time deviation from its net *withdrawals and injections* in the Day-ahead Market, whenever that deviation increases the Market Participant's spot market sales or decreases its spot market purchases.

3.2.7 Billing.

(a) PJMSettlement shall prepare a billing statement each billing cycle for each Market *Participant* in accordance with the charges and credits specified in Sections 3.2.1 through 3.2.6 of this Schedule, and showing the net amount to be paid or received by the Market *Participant*. Billing statements shall provide sufficient detail, as specified in the PJM Manuals, to allow verification of the billing amounts and completion of the Market *Participant's* internal accounting.

(b) If deliveries to a Market *Participant* that has PJM Interchange meters in accordance with Section 14 of the Operating Agreement include amounts delivered for a Market Participant that does not have PJM Interchange meters separate from those of the metered Market *Participant*, PJMSettlement shall prepare a separate billing statement for the unmetered Market Participant based on the allocation of deliveries agreed upon between the Market *Participant* and the unmetered Market Participant specified by them to the Office of the Interconnection.

Attachment C
PJM Virtual Transactions Whitepaper

Virtual Transactions in the PJM Energy Markets

PJM Interconnection

October 12, 2015

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Executive Summary

PJM Interconnection prepared this paper, which explores the role of financial trading in PJM markets, at the request of stakeholders at the April 21, 2015, Liaison Committee Meeting. Virtual transactions have been an integral part of the PJM energy markets since implementation of the Day-Ahead Market on June 1, 2000. Financial trading also is incorporated in all other organized electricity markets in the United States and elsewhere.

This paper examines:

- the purpose of virtual trading in the PJM energy markets,
- the mechanics by which virtual transactions are submitted and cleared,
- potential problems that can result from virtual transactions, and
- examples that illustrate how market participants utilize virtual transactions.

The paper concludes with PJM-recommended market design and rule changes for stakeholders to consider to improve the effectiveness of virtual trading in the PJM energy markets.

Virtual transactions are sets of bids and offers submitted in the Day-Ahead Market that take financial positions in that market without the intent of delivering or consuming physical power in the Real-Time Market. In PJM, virtual transactions include increment offers, decrement bids and up-to-congestion transactions (UTCs). Virtual transactions can be a valuable component of a two-settlement market such as the PJM market. They have the ability to mitigate both supply-side and demand-side market power by allowing market participants without physical assets to compete with asset owners and load-serving entities in the market.

Overall, virtual trading benefits the efficient operation of the PJM energy markets. It can assist in attaining efficient market outcomes and improve commitment and price convergence between the Day-Ahead and Real-Time Markets. The participation of financial traders alongside physical asset owners and load-serving entities provides enhanced competition and liquidity to support hedging. Virtual trading generally assists in achieving efficient market outcomes, i.e. Day-Ahead Market outcomes that commit those generation resources that will in fact be needed to serve load in real time.

However, this paper also points out that virtual transactions can have negative impacts on the market and explains, through examples, why certain types of transaction activities, while profitable for traders, do not bring efficiency and may even degrade market operation. When used in certain ways, these transactions profit from the market without adding commensurate benefit, skew transmission flows and congestion patterns in a manner inconsistent with transmission system topology and load levels, and, in large volumes, can significantly degrade the performance of the Day-Ahead Market.

This paper examines the purpose and potential for financial trading to provide efficiencies in PJM markets; however, it is not presented as a complete empirical assessment of financial trading. PJM also acknowledges continuing examination of these questions across organized wholesale electricity markets by the Federal Energy Regulatory Commission's Office of Enforcement, the PJM Independent Market Monitor, and analysis offered by industry participants.

Based on the work summarized in this paper, PJM has concluded that rule reforms are needed to address financial trading in certain circumstances and under certain conditions. These reforms should be pursued immediately. The paper presents preliminary rule changes to ensure that financial trading does not impose costs without returning reasonably expected benefits to the market.

PJM's proposals would align eligible trading points for increment offers and decrement bids with the locations where physical generation, load and interchange transactions are settled in addition to trading hubs, and, change the biddable locations for UTCs to active generation buses as sources, trading hubs, load zones and interfaces. Additionally, PJM proposes leveling the allocation of uplift across virtual transactions by allocating uplift to a UTC transaction in a manner that is consistent with increment offers and decrement bids. These recommendations are intended to eliminate a significant amount of the negative aspects of virtual trading while preserving their reasonably expected benefits.

Currently, PJM has insufficient information to warrant further changes beyond those called for in this paper, which are common-sense reforms. Further analysis to support a shared consensus for change is warranted before departing from or qualifying long-standing principles and academic and theoretical assumptions which support financial transactions as valuable hedging, convergence and liquidity tools.

As the administrator of a large wholesale energy market, PJM's first mission is to operate markets that are efficient, fair and lead to just and reasonable price outcomes. The design changes affecting virtual trading proposed in this paper reflect PJM's assessment of opportunities to improve a well-functioning Day-Ahead Market.

PJM is bound to explain the need for such design changes and collaborate with stakeholders in making these changes. Accordingly, this paper is intended to promote that dialogue and educate stakeholders on why PJM recommends the design changes proposed here. The goal of this discussion is to retain the positive contribution that virtual transactions bring to the market while removing the bulk of the issues they create when used inefficiently under the existing rules.

Background

At the request of several market participants at the April 21, 2015, Liaison Committee Meeting, PJM undertook this report to explore the role of financial trading in PJM markets. Academic and industry analysis, including studies applying actual data either test or prove the validity of long-standing theories and assumptions underlying the basis for financial trading in PJM markets.

This paper adds to the body of work. It is not designed as a comprehensive academic dissertation on financial trading in organized electricity markets. Rather, it is intended to provide a practical platform to examine and address changes to what PJM regards as evident problems.

In order to provide the context necessary to meet its primary purpose, this paper explores:

- the intended use of the transaction type — including the conditions under which each transaction is profitable;
- actual use, including how the transaction type is used today; and
- how the transaction type is actually used in PJM, versus its original intent.

In the section titled Observed Bidding Strategies, PJM identifies several virtual trading strategies it has observed in which virtual trading cannot reasonably be expected to offer efficiencies. These behaviors, in addition to the arguments laid out within this paper, have led PJM to conclude that changes should be made to the rules governing virtual trading.

Synopsis of the Virtual Transactions

What are Virtual Transactions?

Virtual transactions is the name given to purely financial transactions in the PJM energy markets. Virtual transactions closely resemble financial transactions in other electricity commodity markets and share basic common elements with financially-settled, forward electricity contracts traded bilaterally or on electronic platforms and exchanges (such as the Intercontinental Exchange (ICE), New York Mercantile Exchange (NYMEX) and Nodal Exchange). Virtual trading in organized wholesale energy markets, such as the PJM markets, has been regarded as a valuable market feature because it:

- affords participants with physical assets or load-serving obligations or participants with positions in related markets an opportunity to hedge those positions,
- adds liquidity, enabling market participants to more easily and efficiently take on or close out forward positions,
- allows for both speculative and arbitrage trading to enhance market efficiency through price convergence and unit commitment convergence between the day-ahead and real-time markets; and
- serves to mitigate structural market power through the addition of competitive entities whose participation prevents persistent market distortions.

Virtual transactions in PJM are bids and offers submitted to take financial positions in the Day-Ahead Market without the intent of delivering or consuming physical power in the Real-Time Market.

Virtual transactions include increment offers (INCs), decrement bids (DECs) and up-to-congestion transactions (UTCs). The financial positions taken in the Day-Ahead Market by these types of transactions are settled as imbalances in the Real-Time Market.

Increment Offers

INCs are offers submitted in the Day-Ahead Market to sell an amount of energy at a specific location (node) if the day-ahead clearing price for that node equals or exceeds the offer price. INCs can be thought of as virtual transactions that emulate generation offers in the Day-Ahead Market.

INCs are currently allocated real-time uplift charges and are generally profitable when the day-ahead clearing price exceeds the real-time clearing price.

Decrement Bids

DEC bids are almost the exact opposite of INC offers. DECs are submitted into the Day-Ahead Market as a bid to purchase energy at or below a specified price. DECs can be thought of as virtual transactions that emulate load buy bids in the Day-Ahead Market.

DECs are currently allocated day-ahead and real-time uplift charges and are generally profitable when the day-ahead clearing price is lower than the real-time clearing price.

Up-to-Congestion Transactions

A UTC is a bid in the Day-Ahead Market to purchase congestion and losses between two points. UTC bids can be based on the prevailing flow direction where the UTC is buying a position on the Day-Ahead Market congestion, or they can be in the counterflow direction where they are paid to take a position. The UTC bid consists of a specified source and sink location and a "bid spread" that identifies how much the market participant is willing to pay for a congestion and loss position between the source and the sink.

UTCs are not allocated uplift. For prevailing flow UTCs, profitability occurs when the real-time congestion is in excess of the congestion purchased day-ahead. For counterflow UTCs the opposite is true.

What They Do

Virtual transactions are a valuable component of a two-settlement market such as the PJM market. They have the ability to mitigate both supply-side and demand-side market power by allowing market participants without physical assets to compete with asset owners and load-serving entities in the market.

Because virtual transactions compete with physical resources in the Day-Ahead Market, they can either displace, or cause additional scheduling of, physical resources and load, including price-sensitive demand bids. These changes in the Day-Ahead Market outcome due to virtual transactions may or may not match what is needed in the Real-Time Market. Regardless, the Day-Ahead Market results, including resource commitments, dispatch and pricing, all are impacted by virtual transactions every day.

How They Function

A market participant submitting a virtual transaction that clears takes a financial position in the Day-Ahead Market by agreeing to buy or sell energy at a specific location or locations that it then liquidates in the Real-Time Market. This occurs because the energy that is bought or sold in the Day-Ahead Market is not provided or consumed in real-time and creates an imbalance between the markets.

The PJM two-settlement system then settles all quantity (megawatts of power) deviations from the Day-Ahead Market at the real-time spot price. Thus, virtual transactions can speculate price differences between the two markets and be profitable.

As stated previously, because virtual transactions compete with physical resources in the Day-Ahead Market, they can displace, or cause potentially unneeded additional scheduling of, physical resources in the Day-Ahead Market that are not required in real time. Virtual transactions may also impact the dispatch of physical supply resources and clearing price-sensitive demand bids in the Day-Ahead Market, thus altering the outcome of the Day-Ahead Market, which is used to set an operating plan for the upcoming operating day.

Virtual transactions can benefit the market in several different ways that are discussed throughout this paper. However, by competing with physical resources in the Day-Ahead Market, virtual transactions can affect how physical resources are scheduled and dispatched, impacting Locational Marginal Price (LMP) and uplift costs.

Efficiencies of Virtual Trading

Wholesale electricity is a volatile commodity with prices that can move dramatically in hours. This volatility supports a market design that allows the hedging of inter-day price risk. PJM's two-settlement energy markets (day-ahead and real-time) afford hedging only 24 hours in advance of the spot market. Parties looking for longer-dated hedges to protect against PJM price volatility must turn to other markets (such as Nodal Exchange, ICE or NYMEX) or reach arrangements bilaterally (an asset-tolling agreement or a structured product with a financial risk management services provider such as a bank).

Even with the short tenor of the hedge offered by the Day-Ahead Market, virtual trading has proven itself as a risk management tool for generation owners nominating and scheduling day-ahead and other physical participants, such as Load Serving Entities (LSEs), seeking to lock in a fixed price. It is also a useful risk management tool for both physical and financial participants that have positions in other energy markets, such as ICE. The participation of virtual traders in the PJM Day-Ahead Market provides added liquidity to facilitating these hedging practices. (See *Virtual Transactions as Hedging Instruments*).

The terms *speculative* and *arbitrage* describe related concepts and are frequently used interchangeably. Still, it is helpful to distinguish between these two forms of convergence trading.

Speculative trading identifies a supply-and-demand dislocation in the Day-Ahead Market, relative to what the trader expects will actually occur in real time. A speculator takes on risk; it will put on a long or short position going into real time because it has a view of expected Real-Time Market outcomes that differs from others in the Day-Ahead Market.

Arbitrage reflects trading between two or more price-related instruments or nodes designed to take advantage of mispricing of one, relative to the other. Apparent arbitrage opportunities often arise at the point where energy can be imported into a control area and immediately exported at different prices. Unlike speculation, arbitrage is typically regarded as a risk-free transaction.

In efficient financial and commodity markets, both arbitrage and speculative trading converge prices.

For arbitrage, this convergence can occur in seconds or even milliseconds and the price inefficiency is said to be "arbed out." In the case of speculative trading, convergence can occur less rapidly, but consistently profitable speculative opportunities do not persist in efficient and transparent markets. In large part, this is because the opportunity attracts other speculators whose transactions over time provide added information to correct misperceptions of expected price. In other words, speculative trading, like arbitrage, offers the promise of market efficiency by converging Day-Ahead and Real-Time Market prices. A more detailed illustration of the price convergence benefits of virtual trading is provided further in this paper. (See *Virtual Bidding in a Two-Settlement Market*).

The presence of virtual trading in PJM's energy markets also adds competition and may help to discipline structural market power resulting, in part, from a concentrated ownership of generation. (See below, *Use of INCs to Mitigate Supply-Side Market Power*). The ability for any market participant to become a supplier in the Day-Ahead Market by submitting an INC offer inherently increases the number of suppliers and correspondingly reduces any single supplier's market share.

The theoretical hedging, price convergence and competitive benefits of virtual trading have been demonstrated to a degree through some studies analyzing actual empirical data and efficiency metrics, such as price spreads.[1] This paper builds on these efforts and largely assumes those advantages exist based on their theoretical merits. However, it also identifies situations where actual data and particular market design features illustrate practical realities that plainly call into question the validity of the theoretical premise in such situations.

Unique Attributes of the PJM Energy Markets

Although a virtual transaction is similar to a financial trade as may be found in other energy markets, important features distinguish the PJM energy markets from other commodities or markets, as well as other financial electricity markets. These distinctions are important to consider when examining whether the efficiency values that result from speculation and arbitrage in these other markets can be fully realized in PJM's energy markets.

Virtual transactions participate in single clearing price, auction-based constructs administered by PJM to settle its Day-Ahead and Real-Time Markets.

This stands in contrast to other financial electricity markets where individual buyers and sellers are matched at the price where their respective bids and offers meet. In PJM's markets, the marginal offer sets a single locational clearing price that represents the price paid to all market sellers, including virtual traders.

PJM's financially settled Day-Ahead Market is closely linked with its physically settled Real-Time Market.

The two PJM energy markets are yoked so closely together that the design is often described as a single "two-settlement" market. Clearing the PJM Day-Ahead Market effectively sets a production schedule for more than 1,000 generation and demand response resources in PJM as well as establishing a day-ahead unit commitment for PJM as the system operator. Participants in the Day-Ahead Market include physical market participants – owners of generating stations, many of which are required by rule to submit offers into the Day-Ahead Market, and load-serving entities buying for resale to end-use consumers. As they go about their typical physical operations in real time, which

[1] Harvey S. Virtual Bidding in Forward Power Markets. Presented at Western Power Trading Forum; August 7, 2015; Washington, DC. http://www.lmpmarketdesign.com/papers/Harvey-Financial-Trading8-3-15-final.pdf

Parsons J, Colbert, Larrieu J, Martin T, Mastrangelo E. Financial Arbitrage and Efficient Dispatch in Wholesale Electricity Markets. February 2015. http://www.mit.edu/~jparsons/publications/20150300_Financial_Arbitrage_and_Efficient_Dispatch.pdf is to say generate and inject electricity onto the grid or purchase and consume electricity respectively, the commitments they assumed day ahead are met through physical performance in real time.

Alongside physical market participants are virtual traders. Unlike physical market participants, they own no actual generation or serve no actual load and, thus, are unable to bring physical resources in real time (in the form of supply or consumption) to close out positions they established day ahead. Cleared INCs and DECs in the Day-Ahead Market represent short and long positions for electricity held by these respective financial participants as they go into the Real-Time Market. Performance in the Real-Time Market is physical. In other words, any market participant (including a virtual trader) that does not meet its day-ahead commitments – in full or in part – through physical supply or consumption in real time, will have that imbalance satisfied or met physically by imputed purchases and sales in the Real-Time Market.

In large part due to its physical unit commitment and scheduling mission, the clearing of the Day-Ahead Market and operation of the Real-Time Market are complex.

Price formation in PJM's energy markets is not as straightforward as meeting bids with offers. PJM employs sophisticated optimization software, load forecasting and network models with embedded algorithms that solve for bids and offers while respecting all transmission security constraints, reserve requirements, interchange transactions and generator operating constraints. Assumptions included in, and the operation of, models and rules that produce recommended solutions in light of expected system conditions can contribute significantly to price formation. Since these features can differ across pricing points and between Day-Ahead and Real-Time Market operations, they can create differing prices that cannot be converged by arbitrage trading.

A recent, comprehensive description of the numerous complex factors (beyond bids and offers) that contribute to prices differing in day-ahead and real-time energy markets can be found in *Financial Arbitrage and Efficient Dispatch in Wholesale Electricity Markets*, John E. Parsons, Cathleen Colbert, Jeremy Larrieu, Taylor Martin and Erin Mastrangelo, MIT Center for Energy and Environmental Research, February 2015 (*MIT Paper*). That paper observes that:

> Because the real problem is so much more complex than intersecting a pair of simple supply and demand curves, and because the day-ahead and real-time markets employ algorithms with different approximations, decompositions and judgments, a DA/RT spread can arise even when there is no simple deficiency of supply or demand bid into the Day-Ahead Market. Since the problem is not caused by a simple deficiency of supply and demand, virtual bidding may not help to converge the prices.
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> *MIT Paper* at page 16

Trading in PJM markets is distinguished from other financial and commodity marketplaces by a number of factors. These include the single clearing price in PJM markets; the auction-based structure; the primary design objective to set a production schedule or unit commitment; a scheduling of physical resources, as well as the complex rules, models, algorithms and judgments that can vary between Day-Ahead and Real-Time Markets.

In considering when and to what degree virtual trading offers benefits to PJM markets, it is important to account for these distinctions before definitively concluding that generally accepted principles of market efficiency as demonstrated by trading in other financial and commodity marketplaces hold equally well to PJM's energy markets.

Market Manipulation Concerns

In recent years, organized wholesale electricity markets, including those administered by PJM, have seen an increase in enforcement activities directed at virtual traders by the Federal Energy Regulatory Commission. Physical participants have also attracted enforcement attention and legal reform pursuant to the Energy Policy Act of 2005, and a shifting regulatory focus towards enforcement generally goes a long way to explain the rise in the number of investigations and cases brought by the FERC's Office of Enforcement.

There can be little doubt that incidents of alleged market manipulation stemming from potentially exploitative trading practices have been sufficiently numerous and serious enough to warrant questions as to the cost and benefit of virtual transactions in organized wholesale electricity markets.

While this analysis does not express opinions or raise arguments about the lawfulness, or even the policy questions raised by the trading conduct giving rise to these investigations and cases, there is a common theme in these cases. Traders that claim to have merely followed the rules of the market operator, or at least not offended any explicit prohibition in the rules, are nonetheless subject to enforcement for manipulating the market.

The courts are likely to determine whether a case for manipulation brought by the FERC under the Federal Power Act can lie under these circumstances. If the Commission's theories prevail in court, the enforcement risks that traders confront going forward will at least curtail, and possibly stifle outright, financial trading in organized electricity markets.

If, however, traders prevail on grounds that it is the responsibility of the FERC and market administrators like PJM to close loopholes in market design or operations, then there will likely be a call for dramatic rule changes, perhaps going so far as to eliminate outright virtual trading in RTO markets.

Those unsatisfied with either litigation outcome would be well-advised to explore rules that:

- preserve virtual trading in circumstances where there is a reasonable expectation its theoretical efficiency values can be realized,
- while eliminating clear opportunities for inefficient trading where there is a reasonable expectation that such trading promises little or no value to the market.

Recommended Improvements to Virtual Trading

Notwithstanding the compelling theoretical efficiency value associated with financial trading, certain types of transactions can extract money from the market without adding commensurate benefit, skew transmissions flows and congestion patterns such that they are inconsistent with system topology and load levels and, in large volumes, can significantly degrade the performance of the Day-Ahead Market. Refining the market rules that govern virtual transactions can eliminate a significant amount of the negative aspects of virtual trading while preserving their reasonably expected benefits. Specifically, the rules that determine the available trading locations for INCs, DECs, and UTCs, and the allocation of uplift to these transactions can be improved.

With that in mind, PJM proposes the following changes to the market rules for virtual transactions.

Align the eligible trading points for INCs and DECs with nodes where either generation, load or interchange transactions are settled, or at trading hubs. This would include generator buses where active generators exist, load buses where load is settled nodally, load zones, interfaces and trading hubs.

The intent of this change is to better align the use of INCs and DECs with the physical nature of the Real-Time Market while preserving the ability for such instruments to be used at trading hubs to facilitate longer-term hedges. Under today's rules, INCs and DECs can be placed at nodes where there is no other settlement such as individual load busses. While these types of transactions may be profitable based on differences between the Day-Ahead and Real-Time Markets, they can result in transmission flows and load distributions that are inconsistent with physical reality of the system and potentially result in resource commitments in the Day-Ahead Market that do not align with the system needs in real time. They may aid in price convergence at the specific node, but it is at a location where there is no other settlement and therefore no real change in the incentives to other market participants.

PJM believes that it is extremely important that the Day-Ahead Market produce a resource commitment that closely mimics the set of resources required to operate the system in real time. Allowing INCs and DECs at load busses that can change the load distribution of a zone in a manner inconsistent with PJM's expectation of the real-time load distribution only makes achieving that goal more difficult and more costly. Additionally, INCs and DECs at individual load buses can create congestion patterns inconsistent with the load levels in the Day-Ahead Market. This can cause the Day-Ahead Market to commit resources to control congestion in a zone when what really is needed are additional resources to cover underbid load or the decommitment of resources due to overbid load.

Additionally, this change will reduce unique transaction volume which will improve Day-Ahead Market solution times. This is explained further within this document. (See below, *Virtual Transaction Volumes and Day-Ahead Market Solution Time*).

Alter the biddable locations for UTCs to generation buses as sources only, trading hubs, load zones and interfaces.

For the same reasons as stated for INCs and DECs, in addition to others contained within this paper, PJM believes that the available bidding nodes for UTCs should be changed. In addition to hubs, zones and interfaces, PJM also proposes to allow generator buses as biddable UTC points but only as the source point of the transaction. Permitting

UTCs at interfaces, hubs and zones is intended to continue to permit UTC trading but remove their ability to be used in ways that do not lead to market efficiency. Because these activities are typically enacted nodally, removing individual nodes will remove much of this ability. Notwithstanding the foregoing, PJM does propose to permit UTCs to be submitted with active generation buses as the source point only. This change is proposed to allow market participants trying to hedge generation or load against real-time congestion a method to do that.

Given the volume of UTC transactions, reducing the bidding points would significantly reduce the number of unique UTC transactions and significantly improve Day-Ahead Market performance.

Allocate uplift to UTCs consistent with INC and DEC transactions. Currently, UTCs do not face a similar uplift charge as INCs and DECs, which has led to a significantly greater volume of UTCs compared to INCs and DECs.

The incentives created by the inconsistent allocation of uplift between UTCs, and INCs and DECs can be seen through the specific transaction volumes PJM has seen over the last few years. Currently, UTCs account for approximately 80 percent of all virtual transaction activity and collect more than 81 percent of the total virtual transaction revenues. UTCs have a much smaller risk profile than INCs and DECs due to the lack of allocation of uplift and no exposure to energy price risk between day ahead and real time. Allocating UTCs uplift consistent with INCs and DECs would better align the risk profiles of the transactions as they pertain to fees and help level the uneven playing field that exists today.

PJM believes the allocation of uplift to UTCs is a critical market design change that must be made to remove the competitive advantage afforded today to UTCs.

PJM proposes these suggested market rule changes to stimulate discussion within the stakeholder process. The goal of this discussion is to retain all of the positive aspects that virtual transactions bring to the market while removing the bulk of the issues that they can create when used inefficiently under the existing rules.

In-Depth Review of Virtual Transactions

In general, the use of virtual transactions falls into two categories: price convergence and risk mitigation. Both uses play a vital role in the two-settlement market. However, the transaction type and use have different implications on the scheduling and dispatch of the power system, risk profiles and revenue streams. The multiple facets of virtual transactions must be understood in order to understand how market rules can be further enhanced to maximize the usefulness of virtual transactions.

How Increment Offers Work

INCs are offers submitted in the Day-Ahead Market to sell a stated amount of energy at a specified location. From a Day-Ahead Market clearing perspective, these offers can be thought of as equivalent to a generation offer without temporal restrictions (such as startup times and minimum run times). An INC will clear if the day-ahead clearing price for that node exceeds the offer price. For example, a 10 MWh INC submitted at node A with an offer price of $30/MWh will clear if the Locational Marginal Price (LMP) at that node is equal to or higher than $30/MWh. In this example, the market seller is paid the settled LMP in the Day-Ahead Market, assumed to be $40/MWh, multiplied by the cleared MW amount of the INC and has taken a short position going into the Real-Time Market. The left half of Table 1 shows the day-ahead settlement of the 10 MWh INC.

As is the case with all Day-Ahead Market transactions, a cleared INC does not represent any physical flow or injection of electricity – it establishes a financial position that must be closed out the next day in the Real Time Energy Market[2]. The market seller closes that position in real time (or closes its short position) by purchasing physical supply at the prevailing spot price at the same location the INC was cleared in the Day-Ahead Market. By definition, this electricity was not previously scheduled in the Day-Ahead Market and the purchase therefore creates a MW deviation between the Day-Ahead and Real-Time Markets. The right half of Table 1 shows the closure of the INC position in real time. In this example, the Market Seller purchases real-time energy at $20/MWh which is less than the $40/MWh they were paid in the Day-Ahead Market to sell the power. As a result, the INC makes a profit of $20/MWh or $200 for the full 10 MWh that cleared.

Table 1. Example Increment Offer

INC (MW)	Day-Ahead LMP at INC Location ($/MWh)	Day-Ahead Payment to Market Seller for INC	Real-Time LMP at INC Location ($/MWh)	Cost to Purchase Out of INC Position in Real Time	INC Payoff
10	$40	$400	$20	$200	$200

[2] As is also the case with all activity in the Day-Ahead Market, PJM analyzes and clears the market based on the feasibility of the cleared bids and offers given a transmission model that is intended to be as close as possible to the transmission model that will actually exist in real time. Therefore, while activity in the Day-Ahead Market is not physical in and of itself, PJM endeavors to ensure that the activity that clears in the Day-Ahead Market is physically feasible given the limitations on the transmission system expected to exist during the operating day.

Because a cleared INC represents a commitment assumed in the Day-Ahead Market that must be met with physical supply in real time, it can create deviations between the resource plan cleared in the Day-Ahead Market and what is actually needed for real-time operations the next operating day. In the case of an INC, it can displace economic resources that could have been scheduled in the Day-Ahead Market. These deviations from the optimal resource commitment can result in uplift payments to resources scheduled outside of the Day-Ahead Market in real time. Under PJM's current rules, cleared INC offers pay a share of these uplift charges, as do cleared DEC bids, along with generator, load and transaction deviations. Therefore, absent administrative fees assessed to every bid type, an INC bid is profitable when the following equation is true:

Equation 1.

$$\text{Payoff} = \left[\left(\begin{matrix}\text{Day-Ahead}\\ \text{LMP}\\ (\$/\text{MWh})\end{matrix} - \begin{matrix}\text{Real-Time}\\ \text{LMP}\\ (\$/\text{MWh})\end{matrix} - \begin{matrix}\text{Real-Time}\\ \text{Uplift Charge}\\ (\$/\text{MWh})\end{matrix}\right)\right] * \begin{matrix}\text{Cleared}\\ \text{MWh}\end{matrix}$$

INCs were originally implemented in June 1, 2000, coincident with the implementation of the Day-Ahead Market and have remained unchanged since.

How Decrement Bids Work

DEC bids are almost the exact opposite of INC offers. DECs are submitted into the Day-Ahead Market as a bid to purchase a stated amount of energy at a specified price at a specific location. From a Day-Ahead Market clearing perspective, cleared DEC bids can be thought of as additional demand or load. A DEC will clear the Day-Ahead Market if the day-ahead price at that location settles at or below the price specified by the DEC.

For example, if a DEC is submitted into the Day-Ahead Market for 10 MWh at node A at a price of $60/MWh, the market buyer is bidding to purchase 10 MWh of energy at node A if the LMP at that location settles at or less than $60/MWh. The market buyer in this example pays the settled LMP in the Day-Ahead Market, assumed to be $50/MWh, and has taken a long position going into the real time market. The left half of Table 2 illustrates this.

Table 2. Example Decrement Bid

DEC (MW)	Day-Ahead LMP at DEC Location ($/MWh)	Day-Ahead Payment by Market Buyer for DEC	Real-Time LMP at DEC Location ($/MWh)	Payment to Sell Out of DEC Position in Real Time	DEC Payoff
10	$50	$500	$60	$600	$100

In real time, the 10 MWh withdrawal position from the DEC that cleared in the Day-Ahead Market creates deviation between the Day-Ahead and Real-Time Markets that must be settled at the real-time LMP. The market buyer with a cleared DEC must sell or close out its long position from the Day-Ahead Market at the real-time LMP. In this example, assume the real-time LMP is $60/MWh and, therefore, in order to close the long position established in the

Day-Ahead Market, the market seller now sells the 10 MWh purchased in the Day-Ahead Market via the DEC at that LMP. This would result in a profit to the DEC of $10/MWh or $100 for the full 10 MWh transaction.

Like an INC, a DEC creates a deviation between the Day-Ahead and Real-Time Markets. Because a DEC acts like load in the Day-Ahead Market, it can cause changes to the scheduling of resources in the Day-Ahead Market that are not required for real-time operations, which can again result in out-of-market uplift payments to resources called on in real time to resolve the differences. Additionally, DECs require the commitment of resources to serve load in the Day-Ahead Market caused by a cleared DEC. As a result of a DEC being a causal factor for both the commitment of resources in the Day-Ahead Market to cover the load caused by the cleared DEC, and the potential resulting uplift payments in real time due to the MW deviation the DEC causes between the Day-Ahead and Real-Time Markets, a DEC is assessed an uplift charge in both the Day-Ahead and Real-Time Markets. Absent administrative fees, a DEC is profitable when:

Equation 2.

$$\text{Payoff} = \left[\left(\begin{array}{c}\text{Real-Time}\\ \text{LMP}\\ (\$/\text{MWh})\end{array} - \begin{array}{c}\text{Real-Time}\\ \text{Uplift Charge}\\ (\$/\text{MWh})\end{array}\right) - \left(\begin{array}{c}\text{Day-Ahead}\\ \text{LMP}\\ (\$/\text{MWh})\end{array} + \begin{array}{c}\text{Day-Ahead}\\ \text{Uplift Charge}\\ (\$/\text{MWh})\end{array}\right)\right] * \begin{array}{c}\text{Cleared}\\ \text{MWh}\end{array}$$

DECs were originally implemented in June 1, 2000, coincident with the implementation of the Day-Ahead Market and have remained unchanged since.

How Up-To-Congestion Transactions Work

A UTC is a bid in the Day-Ahead Market to purchase congestion and losses between two points. UTC bids can be based on the prevailing flow direction where the UTC is buying a position on the Day-Ahead Market congestion or they can be in the counterflow direction where they are paid to take a position. In either case, like INCs and DECs, UTCs are bids that impose flows on the transmission network in the Day-Ahead Market that do not exist in real time and therefore classify as a virtual transaction. A major difference between an INC or a DEC and a UTC is that an INC or a DEC is a discrete injection or withdrawal at a location whereas a UTC transaction is an injection at a source point and a withdrawal at a sink point. Effectively, the UTC transaction takes an identical MW position at two different locations that from an energy perspective net to zero (absent losses) but do not for congestion and losses.

Like INCs and DECs, UTCs are virtual transactions in the Day-Ahead Market that do not represent the physical delivery of power in real time and therefore represent a deviation between MWs in the Day-Ahead and Real-Time Markets that is liquidated at the real-time LMP. What makes the UTC deviation different from a discrete INC or DEC deviation is that the UTC is both a supply and demand deviation because it has a source and sink. This makes the UTC identical to an INC offer at the source point and a DEC bid at the sink that are cleared simultaneously.

More specifically, forward flow UTCs (i.e. UTCs where the LMP in the Day-Ahead Market is lower at the source point than it is at the sink point) are profitable when they increase day-ahead congestion such that it is closer to the congestion observed in real time. In the counterflow direction (i.e. UTCs where the LMP in the Day-Ahead Market is higher at the source point than it is at the sink point), UTCs are profitable when they relieve day-ahead congestion on a path that is less constrained in real time.

Because UTCs are profitable when they drive congestion between the Day-Ahead and Real-Time Markets closer to each other, they also work to converge price spreads between both markets but not necessarily convergence of prices at discrete source and sink locations themselves. This is because the profitability of a UTC does not depend on all three components of the LMP (energy, congestion and losses) but only congestion and losses. As a result, energy component differences between the day-ahead and real-time LMPs are irrelevant when it comes to a UTC's profitability because, absent losses, the source and sink energy positions offset each other.

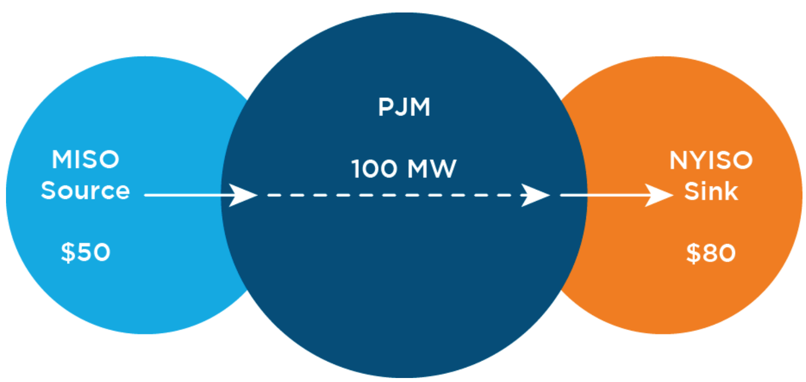
Absent administrative fees, UTCs are profitable when:

Equation 3. UTC Profitability

$$\text{Payoff} = \left[\left(\begin{array}{c}\text{Real-Time}\\ \text{LMP "B"}\\ \$/\text{MWh}\end{array} - \begin{array}{c}\text{Real-Time}\\ \text{LMP "A"}\\ \$/\text{MWh}\end{array}\right) - \left(\begin{array}{c}\text{Day-Ahead}\\ \text{LMP "B"}\\ \$/\text{MWh}\end{array} - \begin{array}{c}\text{Day-Ahead}\\ \text{LMP "A"}\\ \$/\text{MWh}\end{array}\right)\right] * \begin{array}{c}\text{Cleared}\\ \text{MWh}\end{array}$$

A simple example that illustrates the benefits of a UTC is in the modeling of a wheel-through transaction in the Day-Ahead Market. A wheel-through transaction is one where a market participant purchases power from a balancing authority that is external to PJM and transfers that power through PJM to another external balancing authority. The example provided in Figure 1 shows how a UTC can be used to accurately model a wheel-through transaction in the Day-Ahead Market.

Figure 1. Example UTC



In this example, a market participant would like to purchase power in MISO and deliver it to NYISO through PJM. The market participant would only like to execute this transaction if the cost of congestion and losses for the transaction are less than $50/MWh. From a Day-Ahead Market clearing perspective, this means that the transaction will only clear when the price difference between the NYISO interface and the MISO interface is less than, or equal to, $50/MWh. When the Day-Ahead Market clears for this case, the NYISO price is $80/MWh and the MISO price is $50/MWh. Because the difference between these prices (NYISO minus MISO) is only $30/MWh, the transaction will clear and be charged $3,000 for the position taken in the Day-Ahead Market.

Table 3. Settlement of Example UTC

UTC Position (MWh)	Day-Ahead LMP Source MISO ($/MWh)	Day-Ahead LMP Sink NYISO ($/MWh)	Congestion & Losses on Path ($/MWh)	Payment to Create UTC
100	$50	$80	$30	$3,000

If this transaction represents a hedge for a physical transaction that takes place in real time, the market participant clearing the transaction now has a hedge to take into real time and can ensure that they will pay no more than $30/MWh in congestion and losses for this transaction up to the 100 MWh cleared in the Day-Ahead Market. If the transaction is purely financial, it is paid the real-time difference between the NYISO and MISO prices due to it deviating by the cleared 100 MWh in real time.

Brief Background on the Evolution of UTCs

UTCs have changed significantly over time. They were originally implemented on June 1, 2000, coincident with the implementation of the Day-Ahead Market and were intended to allow market participants to "lock in" the congestion charge associated with physical interchange transactions at day-ahead LMPs. Since then they have evolved into what is primarily used as a purely financial transaction. The timeline below identifies critical events in the evolution of the UTC product.

- **June 1, 2000:** The product is implemented and intended to be used as a hedge against real-time prices for a physical transaction that would flow during the next operating day. As a result, a transmission service reservation was required to submit a UTC in the Day-Ahead Market. An offer range was placed on the product of +/- $25/MWh, the sources and sinks at which a UTC could be submitted were only those available on OASIS for the purposes of scheduling physical interchange transactions, and either the source point or the sink point or both were required to be a PJM interface pricing point. The product would continue in this form for approximately the next eight years.

- **June 1, 2007:** PJM implements marginal losses. Because UTCs require a transmission service reservation, they are now allocated a portion of the marginal loss surplus along with loads and other point-to-point transmission customers.

- **March 1, 2008:** As a result of a compromise at the Reserve Market Working Group, the maximum price spread for UTCs was increased to +/- $50/MWh but the available source and sink points were decreased. The available paths had increased over time due to market participant requests to add additional sources and sinks to PJM's OASIS. The decrease in available paths was necessary due to infeasible transactions that were being submitted and concern with the volume of transactions being submitted.

- **December 1, 2008:** PJM implements the balancing operating reserve cost allocation method to allocate uplift costs. These rule changes continued to allocate uplift charges to INCs and DECs as "deviations" between the Day-Ahead Market and Real-Time Market but allocated nothing to UTCs. At the time, UTCs were still considered to be a hedge for a physical transaction in real time and therefore would not actually deviate significantly between day ahead and real time. As a result, they were not included in the allocation of uplift costs as were INCs and DECs.

- **July 23, 2010:** PJM is made aware of market participants making large reservations of non-firm point-to-point service on OASIS in certain hours. PJM investigates this behavior and identifies that UTCs are being used for the sole purpose of collecting a share of the marginal loss surplus as opposed to a financial hedge or for convergence trading.

- **September 17, 2010:** As a result of the July 2010 findings, the requirement of a transmission service reservation to submit a UTC transaction into the Day-Ahead Market is removed. This rule change indicates that, even prior to this time, UTCs were being used for reasons other than purchasing a hedge against real-time prices; however, this change cemented the product as purely financial. No changes were made to the uplift allocation to UTCs to assign them a share of uplift as with other virtual transactions.

- **November 1, 2012:** The previous requirement to have one end (source or sink) of a UTC be an interface point is removed as a result of stakeholder discussion.

Price Convergence and Commitment Convergence

Virtual transactions are often thought of as tools that market participants can use as revenue opportunities while helping to converge prices between the Day-Ahead and Real-Time Markets. While this is true, price convergence only represents a portion of the value added by virtual transactions. In addition to promoting competition and mitigating market power, virtual transactions have the ability to enable the efficient scheduling of the physical assets on the power system needed to cost effectively maintain reliability during the subsequent operating day. This "commitment convergence" is a vital function of virtual transactions, yet is often overlooked.

As explained above, the PJM energy markets are unique in part because of the comingling of the financial trading represented by virtual transactions and the commitment and scheduling of physical assets and actual electricity consumption. Virtual transactions that impact prices in the Day-Ahead Market but that do not result in physical resource commitments that more closely reflect what are actually needed in real time do not result in more efficient market operation. The concept of converging the commitments between day ahead and real time is complicated considering that virtual transactions are often thought to offset the scheduling of physical assets. For example, in the Day-Ahead Market it is entirely possible for an INC transaction to clear and displace the scheduling of a physical generation resource. Consider the following two potential scenarios of what happens when an INC offer clears in the Day-Ahead Market.

1. The generation resource that was supplanted by the INC was not needed in real time and therefore the INC has avoided this additional system cost. In most cases the INC will be profitable and has aided in converging the commitments between day ahead and real time.

2. The generation resource that was deferred in the Day-Ahead Market was actually needed in Real-Time Market. Either this unit, or a more expensive one, is then committed in real time resulting in higher real-time LMPs – all else equal. In this case the INC has not converged the commitment of resources between day ahead and real time and, consequently, the INC is not profitable because the real-time price is higher than the day-ahead price.

Driving the day-ahead commitment closer to what is needed in real time to maintain system reliability is an important function provided by virtual transactions. In order for virtual transactions to accomplish this function, they must impact the scheduling and commitment of the physical resources on the system. When this is done in a direction leading to a day-ahead resource commitment that more closely aligns with real-time needs, market clearing prices will reflect this and the transaction will be profitable. When the opposite occurs, the transaction will not be profitable and, therefore, the market participant is incentivized not to submit the same transaction again.

If there are persistent scenarios found where virtual transactions drive physical unit commitments in the Day-Ahead Market that are different than real time and yet the transactions are still profitable, or, in cases where virtual transactions are cleared that are not meaningfully impacting the day-ahead resource commitment yet are extracting profits from the market, not only is there no value added, but the transactions are actually detrimental to efficient market operation.

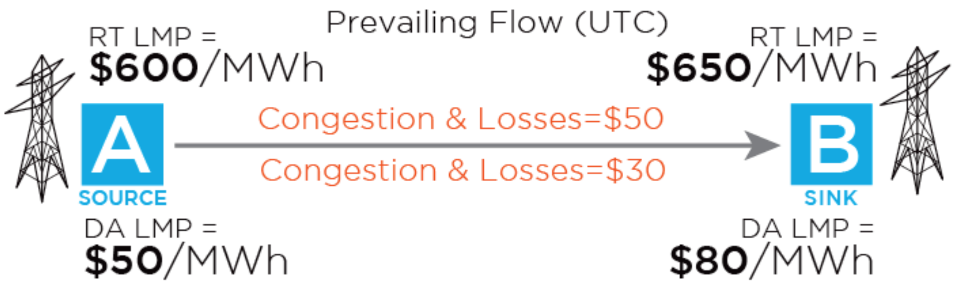
Differences between INCs and DECs, and UTCs

Transaction Characteristics

An important distinction between INCs and DECs, and UTCs is that absent uplift payments, the profitability of an INC or a DEC bid is based purely on the difference between the day-ahead and real-time LMPs at a specific single pricing point. A UTC's profitability is based on the difference between day-ahead and real-time price spreads at the source and sink points. While this difference seems straightforward because the UTC is a transaction with a specified source and sink, there are some underlying complexities to consider. Notwithstanding the current administrative fees assessed to UTCs, the following principles apply to UTCs in the prevailing flow direction.

1. The UTC is profitable when the difference between congestion and loss prices for the source and sink points is greater in real time than it is in day ahead. Under the scenario in Figure 2, the UTC has imposed forward flow between two points in the Day-Ahead Market and paid congestion and losses for that position. In real time, that flow does not occur and therefore the removal of the UTC "relieves" congestion between the same source and sink at a higher price spread than was paid for in the Day-Ahead Market.

Figure 2. UTC Clearing Example



For example, if in the Day-Ahead Market there is a price spread of $30/MWh on the path from A (source) to B (sink) as shown at the bottom of Figure 2. If a 10 MWh UTC position is taken in the direction of A to B, in order for that position to be profitable, the price spread between A and B needs to be greater in real time than it is in day ahead.

Table 4. UTC Day-Ahead Settlement

UTC Position (MWh)	Day-Ahead LMP Source ($/MWh)	Day-Ahead LMP Sink ($/MWh)	Congestion & Losses on Path ($/MWh)	Payment to Create UTC Position
10	$50	$80	$30	$300

Table 4 illustrates the day-ahead settlement for a 10 MWh cleared UTC from A to B. The cleared transaction imposes a flow from A to B and as a result pays $300 of congestion and losses based on the cleared 10 MWh and the $30/MWh price separation between the source and sink.

Table 5. UTC Balancing Settlement 1

UTC Position (MWh)	Real-Time LMP Source ($/MWh)	Real-Time LMP Sink ($/MWh)	Congestion & Losses on Path ($/MWh)	UTC Closure	UTC Payoff
10	$600	$650	$50	$500	$200

For that transaction to be profitable, the price spread in the Real-Time Market needs to be more than $30/MWh, regardless of what the actual source and sink prices at nodes A and B are. In the example in Figure 2, the real-time LMPs at the source and sink are $600/MWh and $650/MWh, respectively. Table 5 illustrates the balancing settlement for the cleared 10 MWh UTC. In this example, the UTC trader has taken a 10 MWh position from A to B that it has paid $300 for in the Day-Ahead Market. In real time, the UTC flow is not imposed on the path from A to B and therefore the trader sells its long flow position at the real-time price difference between A and B, now $50/MWh. This results in a $500 credit back to the UTC trader for a net payoff of $200.

Table 6. UTC Balancing Settlement 2

UTC Position (MWh)	Real-Time LMP Source ($/MWh)	Real-Time LMP Sink ($/MWh)	Congestion & Losses on Path ($/MWh)	UTC Closure	UTC Payoff	UTC Payoff per MWh
10	$50	$100	$50	$500	$200	$20

Table 6 illustrates the same UTC settled under a different set of real-time LMPs but with the same level of price separation. In this case, the real-time LMPs at the source and sink locations are $50/MWh and $100/MWh, respectively. Because the price separation is the same, the profitability of the UTC remains the same.

2. If both the source and sink points of a UTC are analyzed independently as if they were discrete INC and DEC transactions, only one of those transactions needs to be profitable in order for the transaction to be profitable as a whole. As long as one end of the transaction is more profitable than the loss incurred by the other, the transaction, as a whole, makes money. This means that a UTC can be profitable as a whole even when one end of the transaction is not individually rational. This occurs in about 90 percent of all cleared UTCs. The following example illustrates this concept.

Figure 3. UTC Clearing Example

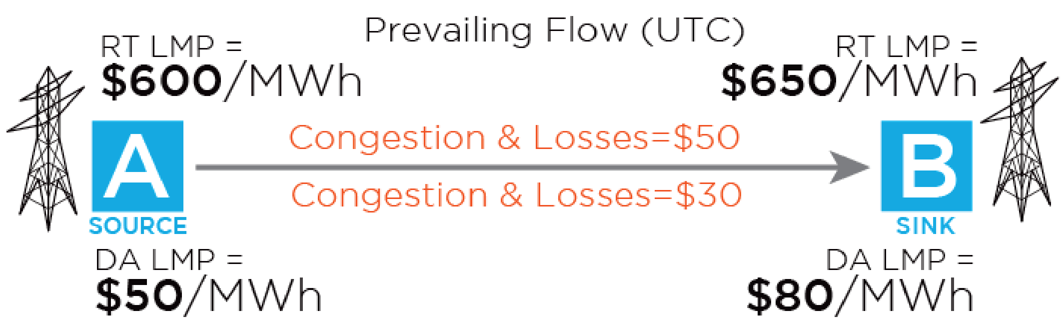


Figure 3 shows the same cleared UTC as used in the previous example with the same set of day-ahead and real-time LMPs. Table 7 shows the settlement of this cleared UTC transaction from a different perspective. While it results in the same UTC payoff, the settlement of each end of the transaction in isolation and then combining the total illustrates how each end of the transaction impacts the market differently.

Table 7. UTC Balancing Settlement on Injection and Withdrawal

UTC Position (MWh)	Real-Time LMP Source ($/MWh)	Real-Time LMP Sink ($/MWh)	Day Ahead LMP Source ($/MWh)	Day-Ahead LMP Sink ($/MWh)	UTC Source Payoff	UTC Sink Payoff	UTC Payoff
10	$600	$650	$50	$80	-$5,500	$5,700	$200

The settlement of the source end of the UTC at node A can be handled exactly like an INC transaction without the uplift considerations. In this example, the UTC trader sells 10 MWh in the Day-Ahead Market at a price of $50/MWh for a credit of $500 and must purchase out of that position in real time at a price of $600/MWh. This results in a loss of $5,500 to the UTC trader for the injection portion of the UTC. The withdrawal portion of the UTC can be treated exactly like a DEC. The UTC trader has cleared a 10 MWh withdrawal in the Day-Ahead Market at the sink location at a price of $80/MWh and is charged $800. In real time, the UTC trader sells that long position back into the market at $650/MWh and profits $5,700. When the independent source and sink settlements are combined they yield the original $200 UTC payoff.

Separating the settlement into injection and withdrawal components shows how each end can impact the market in very different ways. In the case of the injection or source end of the UTC, when considered as an INC transaction, it alone is not profitable which indicates that at the source location there was more supply in day ahead than in real time. That additional supply in day ahead further reduced the day-ahead LMP below real time causing a larger price divergence and thus the injection end of the UTC loses money.

The opposite occurs on the withdrawal or sink end of the UTC. The additional load at the withdrawal end from the UTC adds load at the sink location that serves to increases prices in the Day-Ahead Market beyond what they would otherwise be without the UTC. This means that the withdrawal end of the UTC helps converge prices at the sink location and therefore the withdrawal end of the UTC is profitable.

While the injection portion of the UTC loses $5,500, the withdrawal end profits by $5,700 and therefore on net, the transaction is profitable. Ideally, a DEC at the receiving end of the transmission constraint would have resulted in the most profitable outcome for the market participant and the most benefit to the market absent any major shift in the market clearing caused by removing the injection portion of the transaction. While the UTC was profitable, it created a divergence in prices at the source end which resulted in a $5,500 loss. The convergence provided on the sink end resulting in $5,700 profit is enough to cover that loss.

Factors Impacting Risk

Another factor that differentiates the UTC from an INC or a DEC is the risk types and levels associated with the different transactions. INCs and DECs settle based on LMP differences between the Day-Ahead and Real-Time Markets and therefore face risks on all three LMP components (energy, congestion, and losses). In the case of the UTC, the bid is effectively a point-to-point transaction with two energy positions that absent losses net to zero financially. This occurs because the energy component of LMP is, by definition, the same at every point on the system. Since the settlement of a UTC transaction is based upon the difference in LMP between two points on the system, the energy component of LMP nets to zero and therefore the transaction is only exposed to differences in the congestion and loss components of LMP between the Day-Ahead Market and Real-Time Market. Because the congestion and loss components of LMP differ across the system under constrained conditions, the risk level of each UTC will be dependent on the source and sink points chosen. If there is a very low probability that the path on which the UTC is cleared in the Day-Ahead Market will have congestion in the opposite direction in real time, then the UTC is a very low-risk transaction. As the probability of congestion in the opposite direction of the cleared UTC increases, the risk level also increases.

Finally, the allocation of uplift charges to INCs and DECs adds an additional risk to those transactions that UTCs do not have to manage. Under today's rules, UTCs effectively net the source and sink positions whereas similar positions taken by discrete INC and DEC transactions do not net. While this netting is not explicit within the existing rules, it inherently exists because UTCs are not allocated uplift today because of how the transaction type has evolved over time. This netting of injection and withdrawal positions results in no uplift allocation to UTCs which impacts the bidding behavior of these transactions. As will be shown later, a majority of the bids submitted for UTCs are between positive and negative $2.00/MWh. An allocation of uplift to these transactions would make these transactions not profitable in many cases.

More information regarding recent levels of uplift and its impact on the profitability of different virtual bid types can be found in Appendix A.

Virtual Bidding in a Two-Settlement Market

Spot Market Price Arbitrage

Virtual transactions add value to a two-settlement market in a number of ways. In their simplest application, they can be used to converge price differences between Day-Ahead and Real-Time Markets when physical positions are not represented in day ahead as they occur in real time. For example, if the load, generation and interchange in the Day-Ahead Market were identical to what occurred in real time, the cleared quantities and prices would be identical between the two markets and virtual transactions would not be profitable. However, when the offered quantities or prices in the Day-Ahead Market differ from what occurs in real time, virtual bids add value in a number of ways.

Under today's market rules, the only entities required to make an offer into the Day-Ahead Market are generation owners of capacity resources. These resource owners are required to offer the committed capacity value of their resource into the Day-Ahead Market unless the resource is on an outage. However, notwithstanding PJM's market power mitigation measures, generation capacity resource owners have the ability to submit offers that can potentially price them out of the Day-Ahead Market via their market-based offer, depending on their bidding strategy. Those resources that do not clear in the Day-Ahead Market then have the opportunity to rebid prior to the Real-Time Market and be committed via the PJM Reliability Unit Commitment process.

Load Serving Entities (LSEs) in PJM are not required bid their load into the Day-Ahead Market. This market design was chosen for two main reasons. First, it allows LSEs the maximum amount of flexibility in how they procure the needed supply to meet their load the following day. They may procure all of their energy needs day ahead, none, or somewhere in between depending on their willingness to pay along with their risk profile. Second, having the Day-Ahead Market clear based on the demand submitted by the members rather than the load forecasted by PJM removes the influence PJM's load forecast accuracy would have on the market both in the short and long term. This eliminates any biasing that could have existed based on load forecast accuracy and leaves the supply and demand dynamics of the market between market participants.

While there is no requirement for LSEs to bid in the Day-Ahead Market, there are financial incentives to do so. LSEs that lock in their position in the Day-Ahead Market are not exposed to potential price volatility in real time and also avoid deviation charges that apply to entities with schedule imbalances between day-ahead and real-time load positions. On average, fixed demand bids in the Day-Ahead Market account for about 95 percent of the load forecast for the next operating day. On a peak load day where the real-time load is about 150,000 MW, five percent of the load is 7,500 MW which is equivalent to about seven nuclear plants. On a percentage basis it is small but in terms of real megawatts it is substantial. Without some form of virtual trading, this amount of load could go un-procured in the Day-Ahead Market leading to discounted prices and inadequate resource commitments.

The flexibility allowed to both LSEs and generation owners in the Day-Ahead Market on how their assets are represented in the Day-Ahead Market creates differences between the Day-Ahead and Real-Time Markets in addition to market power issues. The market power issues arise from either the LSEs or generation owners being able to exert market power over the other on an aggregate basis. For example, if LSEs underbid load in the Day-Ahead Market by 20 percent, the resulting market outcome absent virtual bidding would be a procurement of 80 percent of the expected supply needed the next day at a fraction of the cost of procuring the full 100 percent of expected supply needed.

Real-Time Spot Market Only

The most basic market design is one with a real-time spot market only. In this case, all settlement in the market is done at the real-time price. An example of this is provided below in Figure 4 where for an example hour, the aggregate system supply curve is shown via the positively sloped line and the real-time load is 1,800 MWh. In this case, the real-time clearing price is shown by the intersection of the supply and demand curves at $60/MWh. Because all load and generation is settled at the real-time price, the total money collected from loads and paid to suppliers is $108,000. Table 8 illustrates the settlement for this market outcome.

Figure 4. Real-Time Spot Market Only

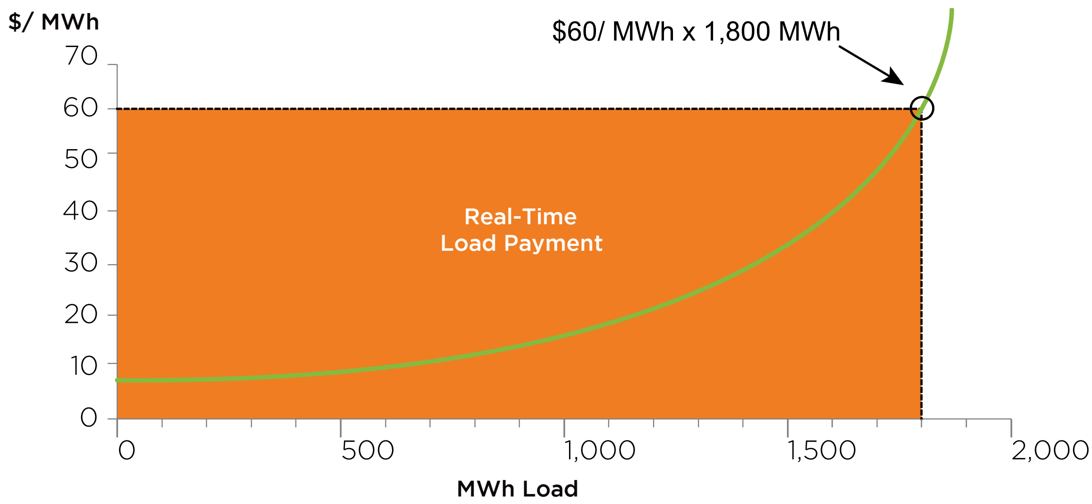


Table 8. Real-Time Spot Market Settlement

Real-Time Load (MWh)	Real-Time Price ($/MWh)	Real-Time Load Payment
1,800	$60	$108,000

Two-Settlement Market: No Virtual Bidding

The example shown in Figure 5 graphically illustrates a two-settlement system like PJM's but without any virtual bidding. The purpose of this example is to show that absent virtual transactions, LSEs have monopsony power that can be exerted to purchase much of the required supply at a discount to what they would otherwise have to pay in real time. In this system, the demand cleared in the Day-Ahead Market is 1,600 MWh at a clearing price of $40/MWh. In real time, the actual system load is 1,800 MWh at a clearing price of $60/MWh, similar to the previous example. In this scenario, LSEs have underbid demand in the Day-Ahead Market and it has resulted in a clearing price lower than what is observed in real time at the load level of 1,800 MWh. The region in Figure 5 labeled "Day-Ahead Demand Payment" represents the total payments in the Day-Ahead Market by the cleared day-ahead demand to cleared supply resources. The region labeled "Real-Time Load Payment" shows the amount of money paid by real-time, unhedged load that has not cleared in the Day-Ahead Market. The region labeled "Day-Ahead Market Discount to Real Time" represents the amount of payments that load has avoided by underbidding in day ahead and procuring 1,600 MWh of the 1,800 MWh needed in real time at a discounted price.

Figure 5. Two-Settlement Market Without Virtual Bidding

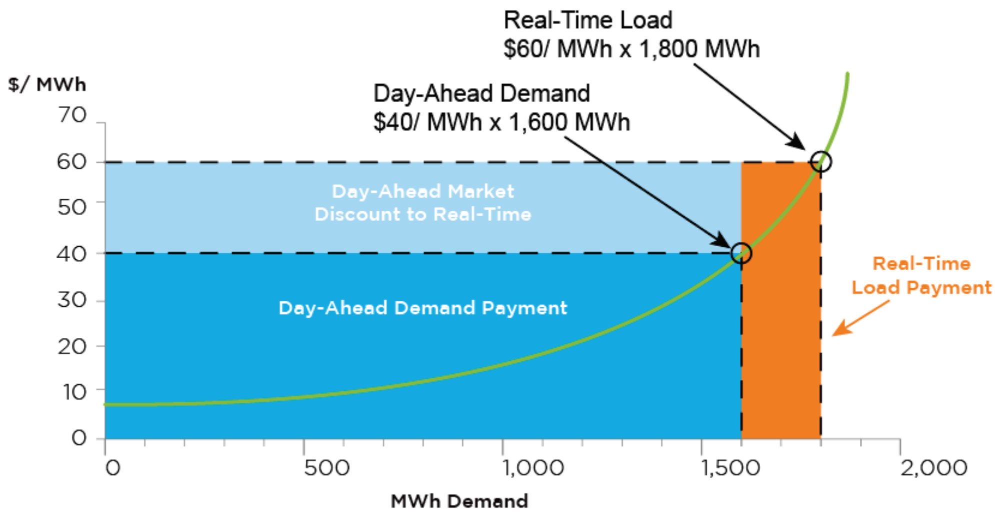


Table 9. Two-Settlement Market Without Virtual Bidding Settlement

Day-Ahead Demand (MWh)	Day-Ahead Price ($/MWh)	Real-Time Load (MWh)	Real-Time Price ($/MWh)	Balancing Load in Real-Time (MWh)
1,600	$40	1,800	$60	200

As stated previously, this example illustrates that absent virtual bidding, LSEs have monopsony power because of their ability to underbid in the Day-Ahead Market and purchase much of the supply required in real time at a discount. The effect of this is illustrated in Table 10. The total payment from cleared demand in the Day-Ahead Market in this example is $64,000. This is shown in the section labeled “Day-Ahead Demand Payment”. The section labeled “Real-Time Load Payment” totals $12,000 and represents the payments made by real-time, unhedged loads for the additional 200 MWh of supply required in real time in excess of the 1,600 MWh procured day ahead. The sum of these two, $76,000, represents the total payments by load and demand to supply resources to procure 1,800 MWh of supply. This is $32,000 less than the $108,000 settled in the prior example where there was no Day-Ahead Market. This cost reduction of $32,000 is shown in the shaded region of Figure 5 titled “Day-Ahead Market Discount to Real-Time Load” and in this example is a direct result of demand in day ahead being bid in at levels that are lower than those observed in real time.

Table 10. Total Settlement for Two-Settlement Market Without Virtual Bidding

Payment from Day-Ahead Demand	Real-Time Balancing Payments	Total Supplier Settlement	Cost Avoided by Load
$64,000	$12,000	$76,000	$32,000

Consistent underbidding by demand in the Day-Ahead Market and the resulting suppression of the day-ahead prices would be extremely detrimental to the long-term health of the market because the prices resulting from the PJM spot market drives forward prices in other markets. The ability for both suppliers and load to build a portfolio of short- and long-term forward contracts to hedge their market positions is critical to their ability to manage their risk. Price suppression in the Day-Ahead Market would severely impede the efficient functioning of the markets for these longer-term hedges.

Two Settlement Market with Virtual Bidding

The introduction of virtual transactions, in this case a DEC, is extremely helpful in mitigating this monopsony power. Consider the same example but now with a 100 MWh DEC that has fully cleared and set the Day-Ahead Market clearing price as shown Figure 6. The cleared DEC in this case is converging the Day-Ahead and Real-Time Markets by increasing the demand and price in the Day-Ahead Market closer to what is observed in real time. The additional 100 MWh of demand provided causes an increase in the supply needed to meet the demand in the Day-Ahead Market and a corresponding increase in price.

Assume in this case that the cleared DEC was not submitted by an LSE as part of a load-hedging strategy but rather by a financial trader. The financial trader believes that the real-time LMP will be greater than $50/MWh and therefore submits the DEC bid with an offer price of $50/MWh. If the DEC clears and the real-time price is greater than $50/MWh, the DEC will be profitable as the trader will sell out of the long position at a price that is higher than the cost to take that position.

Figure 6. Two-Settlement Market with Virtual Bidding

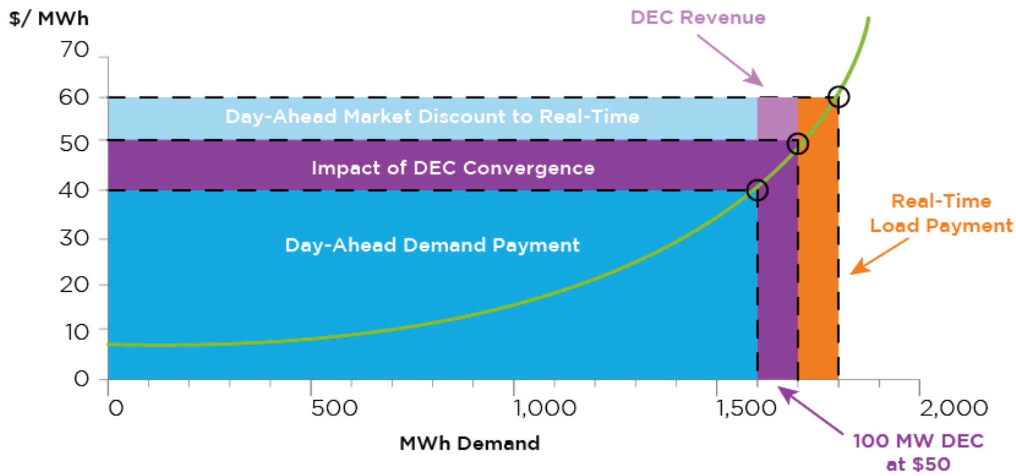


Table 11. Two-Settlement Market with Virtual Bidding

Day-Ahead Demand (MWh)	DEC Position (MWh)	Day-Ahead Price ($/MWh)	Real-Time Load (MWh)	Real-Time Price ($/MWh)	Balancing Load in Real Time (MWh)
1,600	100	$50	1,800	$60	200

From a macro perspective, the cleared DEC has increased demand in the Day-Ahead Market and has also resulted in an increase in price from what it would have been without the DEC. Both of these increases bring the Day-Ahead Market clearing closer to real time. The new dark purple shaded region titled "Impact of DEC Convergence" shows the amount of convergence created by the cleared DEC. The light purple shaded region titled "DEC Revenue" shows the profit made by the DEC transaction. Additionally, both the "Day-Ahead Market Discount to Real Time", which includes the light purple section, and the "Real-Time Load Payment" which illustrate differences between the Day-Ahead and Real-Time Markets have both decreased as a result of the DEC transaction.

Because the clearing price in the Day-Ahead Market has increased to $50/MWh from the prior example, the LSEs who have secured their load in the Day-Ahead Market now pay a total of $80,000 ($50/MWh * 1,600 MWh) for that hedge. The DEC also must pay $50/MWh for the cleared 100 MWh to take the long position in the Day-Ahead Market. The additional demand created by the DEC results in the scheduling of an additional 100 MW of supply resulting in an increase in cleared supply in the Day-Ahead Market. The $5,000 paid by the DEC for its hedge is also used to fund the supply cleared in the Day-Ahead Market. As a result, the total payments from demand to supply in day ahead are $85,000. From the previous example, this is an increase of $21,000.

In real time, the LMP is now $60/MWh as a result of a 100 MWh increase in load above the cleared demand in the Day-Ahead Market. The supply cleared in the Day-Ahead Market is 1,700 MW as a result of the 100 MWh cleared DEC and the 1,600 MWh of cleared demand from LSEs. As a result, only an additional 100 MWh of supply are needed in real time to meet the 1,800 MWh load. It is important to note that because LSEs only cleared 1,600 MWh of demand in the Day-Ahead Market, there is still a balancing load settlement of 200 MWh as the real-time load is 1,800 MWh. This means that real-time, unhedged loads will pay a total of $12,000. Half of that $12,000 is paid to the cleared DEC that closes its 100 MWh long position in real time for $6,000. The remaining $6,000 is paid to the additional 100 MWh of supply required to cover the addition 100 MWh of load in real time.

Table 12. Settlement of Two-Settlement with Virtual Bidding

Payment from Day-Ahead Demand (not including DEC)	Payment to Create DEC Position	Total Day-Ahead Settlement	DEC Closure in Real-Time	DEC Payoff	Real-Time Balancing	Total Supplier Settlement
$80,000	$5,000	$85,000	$6,000	$1,000	$12,000	$91,000

Because the DEC has brought the day-ahead and Real-Time Markets closer together, the DEC makes a profit of $1,000. In Figure 6, this is shown via the light purple shaded region titled "DEC Revenue". Importantly, the profit accrued by the DEC is much smaller than the convergence value it brings to the market as a whole. In this example, the DEC increased the day-ahead clearing price by $10/MWh and increased the day-ahead demand by 100 MWh. This results in an increase in total Day-Ahead Market billing of $21,000. This additional $21,000 increases revenues to suppliers who have cleared in the Day-Ahead Market and brings their settlement closer to what it would have been had they cleared in real time only. The total market billing in this case would be $91,000 which is significantly closer to the original $108,000 in the Real-Time Spot Market Only example than the $76,000 in the prior example without virtual bidding.

The assumption in this example is that the cleared DEC represents a purely financial position and therefore there are still 200 MWh of load that need to be settled in real time at a cost of $12,000. In Figure 6, this is represented via the orange and light and dark purple shaded regions between the amounts of 1,600 MWh and 1,800 MWh. The difference in this example is that for 100 MWh of those 200 MWh, PJM would have already scheduled and compensated supply in the Day-Ahead Market because of the 100 MWh cleared DEC. Therefore, in real time only 100 MWh of additional supply needs to be scheduled and compensated at the real-time LMP. The $12,000 collected from loads in real time that did not hedge day ahead ends up being split between the 100 MWh of additional supply needed in real time and purchasing the long position taken by the DEC that is liquidated in real time. Essentially, the DEC holder sells the supply it procured in the Day-Ahead Market for $50/MWh to unhedged loads in real time at a price of $60/MWh. As a result, the DEC holder profits on the difference between those prices for a total of $1,000.

Table 13 shows the same scenario but with a cleared DEC of 199 MWh. The additional cleared demand in the Day-Ahead Market pushes the day-ahead LMP closer to real time thus providing even greater convergence. The total cleared demand in the Day-Ahead Market has now increased to 1,799 MWh at a clearing price of $58/MWh.

Table 13. DEC Near Convergence – 199 MWh

Day-Ahead Demand (MWh)	DEC Position (MWh)	Day-Ahead Price ($/MWh)	Real-Time Load (MW)	Real-Time Price ($/MWh)	DEC Position (MW)	Balancing Load in Real Time (MW)
1,600	199	$58	1,800	$60	199	200

Table 14 shows the resulting market outcome. Between the payments from cleared demand in the Day-Ahead Market and the DEC, the total day-ahead settlement is now $104,342 which is just below the $108,000 settled in the Spot Market Only example. The $12,000 collected from unhedged load in real time is again split between supply that was not committed in the Day-Ahead Market and the payment required to purchase the supply procured by the DEC in the Day-Ahead Market. Because the DEC position is larger in this example, the payment required to close the DEC's position is larger; however, the payoff to the DEC is much smaller because of the converged prices between day ahead and real time.

Table 14. DEC Near Convergence Settlement

Payment from Day-Ahead Demand	Payment to Create DEC	Total Day-Ahead Settlement	DEC Closure	DEC Payoff	Real-Time Balancing	Total Supplier Settlement
$92,800	$11,542	$104,342	$11,940	$398	$12,000	$104,402

The ideal example of market convergence in this case would be a 200 MWh DEC offered in with a bid price of $60/MWh. This would result in the Day-Ahead Market clearing perfectly matching real time with 1,800 MW cleared at a price of $60/MWh. However, this would also result in the 200 MWh DEC making no profit because the day-ahead and real-time clearing prices matched perfectly. Because INCs and DECs only profit when the real-time and day-ahead prices are not equal, these products alone will not perfectly converge the Day-Ahead and Real-Time Markets. However, they are critical components of the market because they drive markets towards convergence while mitigating market power.

Table 15. DEC at Total Convergence

Day-Ahead Demand (MW)	DEC Position (MW)	Day-Ahead Price	Real-Time Load (MW)	Real-Time Price	DEC Position (MW)	Balancing Load in Real Time (MW)
1,600	200	$60	1,800	$60	200	200

Table 16. DEC at Total Convergence Settlement

Payment from DA Demand	Payment to Create DEC	Total DA Settlement	DEC Closure	DEC Payoff	RT Balancing	Total Supplier Settlement
$96,000	$12,000	$108,000	$12,000	$0	$12,000	$108,000

The examples in this section illustrate the use of DEC bids but similar examples can be constructed using INC offers. This discussion is contained in the following section.

Use of INCs to Mitigate Supply-Side Market Power

As stated previously, generation owners in PJM can submit market-based offers to sell energy that if high enough will result in the offer failing to clear and thus, the associated resource not being committed in the Day-Ahead Market. Market-based offers allow generators to price many risks into their generation offer that their cost-based offers do not permit. For example, a generation owner submitting a day-ahead offer for a resource that has a high risk of tripping in real time may want to reflect that risk in its offer into the Day-Ahead Market. One strategy for this would be to submit a market-based offer that ensures that an at-risk resource does not receive a day-ahead award when the day-ahead LMPs are less than what it anticipates the real-time LMPs will be the following day. This strategy would minimize the financial risk of buying out of the day-ahead commitment in real time should the generator actually trip.

While market-based offers provide generation owners additional flexibility on how to construct their offers above what the prescriptive cost-based offer methodology permits, they also provide the opportunity for generation resources to withhold from the Day-Ahead Market similar to the way LSEs can underbid load positions. For example, in theory, a generation owner could submit a high market-based offer on a resource in the Day-Ahead Market in an attempt to price that resource out of the market, resulting in higher day-ahead LMPs for the rest of its portfolio.

In the prior example, a generation resource owner with a portfolio of assets submits a high market-based offer into the Day-Ahead Market for one resource in the portfolio. The resource owner's goal in this case is to not receive an award on one resource in its portfolio in the hope that the increase in Day-Ahead LMPs from economically withholding one resource results in a net benefit to their portfolio, because of the increased LMPs paid to the remaining committed resources. The generation owner then reduces its offer on the resource during the re-bid period in an attempt to receive a real-time commitment for that resource. The final offer for the withheld resource is one that is infra-marginal based on the Day-Ahead Market results. In this case, the INC offer provides a measure of protection to LSEs trying to hedge in the Day-Ahead Market by allowing virtual supply to moderate, if not eliminate, the price increase.

If we further assume that the resource either received a real-time commitment during the reliability analysis or the generation owner elected to self-schedule the resource, the additional supply from this resource in real time will push real-time LMPs below what they were day ahead, all other things equal. Because the INC profits when day-ahead LMP exceeds the real-time LMP, the artificially increased day-ahead LMPs resulting from the withheld resource provide a revenue opportunity for any market participant to take a position with the INC. In this scenario, any market participant willing to submit and clear an INC in the Day-Ahead Market has the ability to mitigate the generation resource owner's market power.

The INC offer will clear any time the offer price is below the day-ahead LMP. Submitting and clearing an INC offer in this scenario creates supply in the Day-Ahead Market at a level below the day-ahead LMP replacing the supply withheld by the generation resource owner. This additional supply in the Day-Ahead Market moderates the increase in the day-ahead LMP which minimizes or eliminates the revenues the generation owner was attempting to collect. In addition to this, the moderation in the day-ahead LMP increase protects loads from the impacts of the generation owner's behavior.

Market rules and dynamics designed particularly to address supply-side market power serve to limit the role that INCs play to mitigate supply-side market power as compared to the role DECs play to check demand-side market power. The following features, for which there are no analogs on the demand side, illustrate this point:

1. Generation capacity resources owners are required to offer into the Day-Ahead Market. While there is flexibility on how that offer is priced, the "must-offer" requirement for generation capacity resources exists and there is no corollary for loads. This rule removes much of the ability for generation capacity resource owners to physically withhold from the Day-Ahead Market. Some ability still exists if the generation resource owner is willing to take a forced outage but there are significant compliance risks in doing so.

2. Generation capacity resource owners must also submit a cost-based offer that is used in the scheduling and dispatch of the resource when it is determined to have local market power. This removes the ability for a generation capacity resource to withhold their resources economically when they have local market power.

3. Because of the competition inherent in PJM's markets, market participants behave in a competitive manner. The IMM states,

> "Participant behavior was evaluated as competitive because the analysis of markup shows that marginal units generally make offers at, or close to, their marginal costs in both Day-Ahead and Real-Time Markets, although the behavior of some participants during the high demand periods in the first quarter raises concerns about economic withholding."[3]
>
> *2014 State of the Market Report for PJM, page 70*

The additional market rules for generation capacity resource owners in addition to the IMM's statement regarding competitive behavior indicate that outside of infrequent high demand periods, the opportunities for INCs to mitigate supply-side market power are few whereas the market design features of the Day-Ahead Market that result in persistent underbidding of load in the Day-Ahead Market provide opportunities for DEC bids to mitigate demand-side market power much more often. This is likely a primary driver in the reason cleared DEC volume exceeds cleared INC volume over the previous three planning years by a ratio of 1.5 to 1. (See Appendix A for more detail)

Virtual Transactions as Hedging Instruments

One of the primary uses of virtual transactions is to hedge the financial risks inherent in the volatility of the spot energy market. They can be used in a variety of different ways ranging from a simple hedge procured to protect a generation asset from real-time price exposure to a more complex scenario such as converting a forward contract into the physical delivery of power.

An equally important and more complicated usage of INCs and DECs is to convert forward financial contracts used as either risk-based revenue streams or risk-hedging mechanisms into physical deliveries of power. This type of strategy may originate with a forward contract on an open exchange such as the Intercontinental Exchange (ICE) or the New York Mercantile Exchange (NYMEX), or, simply an internal bilateral transaction between two different counterparties, but can incorporate the use of INCs and DECs to fully effectuate a strategy.

Generator at Risk of Tripping

A simple risk mitigation strategy to consider is a generation capacity resource that is required to offer into the Day-Ahead Market but is at risk of tripping in real time on a peak-load day where real-time prices are anticipated to be high. In this case, a generation owner may use a DEC in the Day-Ahead Market to hedge a portion, or all, of the risk of purchasing out of a day-ahead commitment in real time.

Assume the generation capacity resource at risk of tripping is an 800 MW unit. If the resource clears all 800 MWs in day ahead for all 24 hours of the day at an average price of $200/MWh, the resource will be paid a total of $3.84 million. Table 17 shows this settlement.

[3] 2014 State of the Market Report for PJM, Monitoring Analytics
http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2014/2014-som-pjm-volume2-sec3.pdf

Table 17. Generator at Risk – Day-Ahead Clearing

DA Commitment (MWs)	Hours Committed	Average Day-Ahead Price ($/MWh)	Day-Ahead Revenue to Generator
800	24	$200	$3,840,000

However, based on a simple approach, if the generation owner feels that the unit has a 50 percent chance of tripping the next day, then in order to mitigate that risk the owner may submit and clear a 400 MW DEC at the generator bus for all 24 hours of the same day.

Table 18. DEC Position

DEC Position (MWs)	DEC Hours Cleared	Average Day-Ahead Price ($/MWh)	Payment to Create DEC
400	24	$200	$1,920,000

Under PJM's current settlement rules, the DEC and the generation position at the same location do not net against each other. Therefore, the day-ahead settlement for the generator is the same $3.84 million regardless of whether the DEC clears or not. However, the DEC has created a financial hedge for the generator because it was submitted at the same location. In this example, the generation owner would also pay a $1.92 million charge for the cleared DEC that financially offsets the $3.84 million paid to the generation resource. This results in a net settlement of a $1.92 million credit to the generation owner, exclusive of the day-ahead uplift charges allocated to the cleared DEC. Absent the uplift charges, it is the same day-ahead settlement that would have occurred had the generator only cleared for 400 MWs throughout the day.

In real time, any quantity deviations from the day-ahead schedule for both the generator and the DEC are settled at the real-time LMP. If the generator trips, it must buy out of its day-ahead position at the real-time LMP. If it does not and it meets its day-ahead schedule then the balancing settlement for the generator is $0.00 because there are no quantity deviations in the schedule for the generator in real time. Because the DEC is a virtual bid, it deviates in real time for the full 400 MWs that cleared day ahead. The balancing settlement for the DEC is a credit to the generation owner at the value of the real-time LMP in addition to an uplift charge resulting from the deviation.

Regardless of the generator's performance in real time, the generation owner will always receive the real-time LMP for the position established by the DEC when it is liquidated in real time. As a result, the generation owner has created a market outcome that results in being compensated at the day-ahead LMP for half of the resource and the real-time LMP for the other half. From a risk mitigation perspective, if the generator trips in real time the owner must fully purchase out of the 800 MWs position established in day ahead. However, the balancing settlement of the cleared DEC will offset half of those costs because it results in a credit back to the owner at the real-time LMP for half of the unit's output.

Bilateral Transaction with Day-Ahead and Real-Time Pricing

Suppose an LSE wants to bilaterally contract with supply to serve their load rather than be exposed to spot market energy prices. The LSE finds a seller and they agree on a 100 MWh contract at a specific location but the Seller wants real-time pricing and the buyer wants day-ahead pricing. The two parties agree to enter into an internal bilateral transaction (IBT) that is priced at day ahead.

For the buyer, nothing more needs to be done unless it wants to hedge congestion additionally between the location of the IBT and the location of the LSE's actual load. The simplest way to do this would be to procure a Financial Transmission Right (FTR).

For the seller who wants real-time pricing, it would need to clear a 100 MWs INC in the Day-Ahead Market at the location of the IBT.

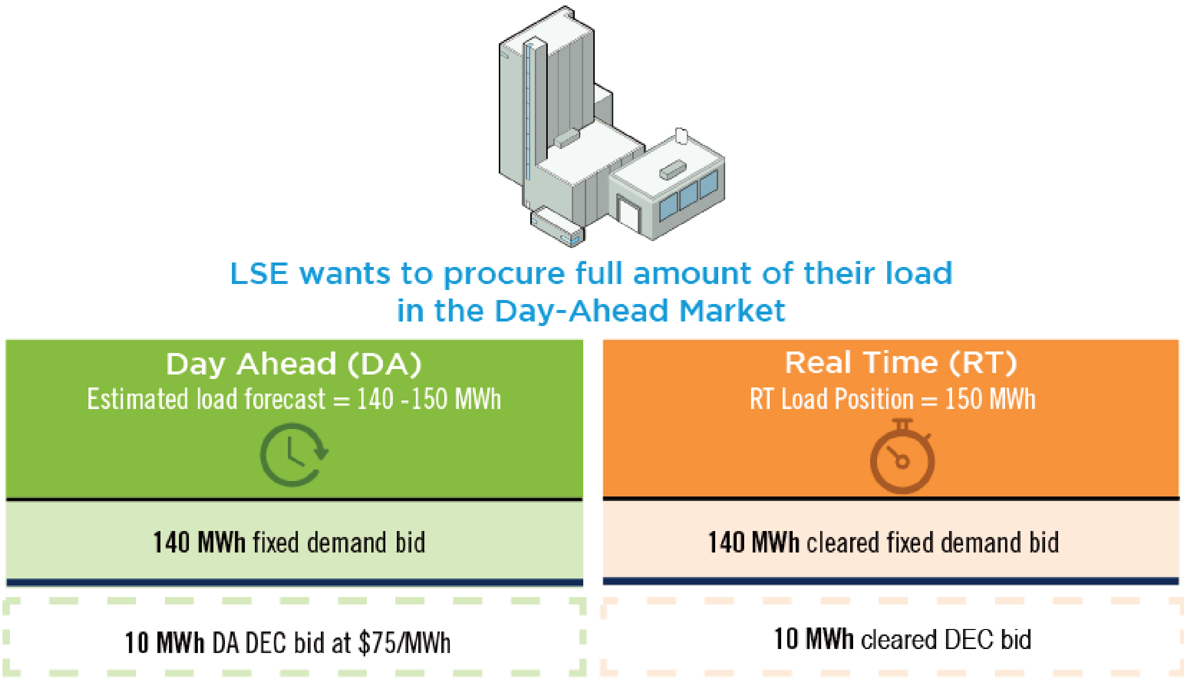
The IBT would result in a net negative position for the seller such that absent any other market activity, the seller would receive a charge for the 100 MWs sold in the IBT. The 100 MWs cleared INC at that same location will financially offset the sell position created by the IBT. The resulting day-ahead settlement for the seller would be a purchase of 100 MWs at the location of the IBT as well as a 100 MWs credit at the same location due to the cleared INC. In real time, the IBT has no deviation and therefore the balancing settlement is zero. However, the liquidation of the INC positon in real time will result in a 100 MWs purchase at the location of the IBT at the real-time LMP. In this scenario, the seller is not charged uplift because the INC is permitted to net with the IBT.

Demand Hedging with a DEC Bid

Another demand-side hedging strategy incorporates the use of DEC bids to express an LSE's willingness to pay for power in Day-Ahead Market at a given price. This practice allows LSEs to procure some portion of their load in the Day-Ahead Market up to a specified price and have the rest procured in real time at the real-time LMP.

Assume that an LSE has estimated their load forecast the next day to be between 140 MWs and 150 MWs for a given hour. The LSE would like to procure the full amount of its load in the Day-Ahead Market if possible but does not know what the exact amount will be. Because the LSE knows that its load will be greater than or equal to 140 MWh, it submits a fixed demand bid in the Day-Ahead Market for 140 MWh. This leaves the LSE with a potential 10 MWh of load exposed to real-time prices.

Figure 7. Demand Hedging



Based on the LSE's risk management strategy, it would prefer to buy an additional 10 MWs of potential load at a price of $75/MWh or less rather than be exposed to real-time prices for those 10 MWs. However, if the day-ahead price exceeds $75/MWh, the LSE would prefer to take that portion of the load into real time. To effectuate this strategy, the LSE can submit a 10 MWh DEC bid into the Day-Ahead Market at a price of $75/MWh.

If the LMP at the load location is $60/MWh such that the DEC clears, the LSE is charged $9,000 ($60/MWh * 150 MWh) and carries a 150 MWh load position into the Real-Time Market. If the LSE's load is less than the cleared 150 MWh position, the LSE will sell out of that position in real time and be paid the real-time LMP for any imbalances on that 150 MW position. Regardless of whether the real-time LMP is higher or lower than the day-ahead LMP, the LSE has been successful in protecting its load from real-time volatility based on its own internal strategy and the use of a DEC bid. If the real-time LMP is higher than the day-ahead LMP of $60/MWh, the LSE will sell back its long load position at the real-time LMP and make a profit on that position.

While it is not the case in this example, if the LSE had a real-time load in excess of 150 MWh, it would have to purchase the balance at the real-time LMP.

Virtual Transaction Volumes

Figures 9 and 10 show the trend in submitted and cleared volumes of virtual bids, respectively. Both of these figures show generally the same trend, which is a reduction in the number of INCs and DECs that have been submitted and cleared since 2008 and a meteoric rise in the amount of submitted and cleared UTCs up until September of 2014.

Figure 8. 12-Month Rolling Average of Submitted Virtual Transactions

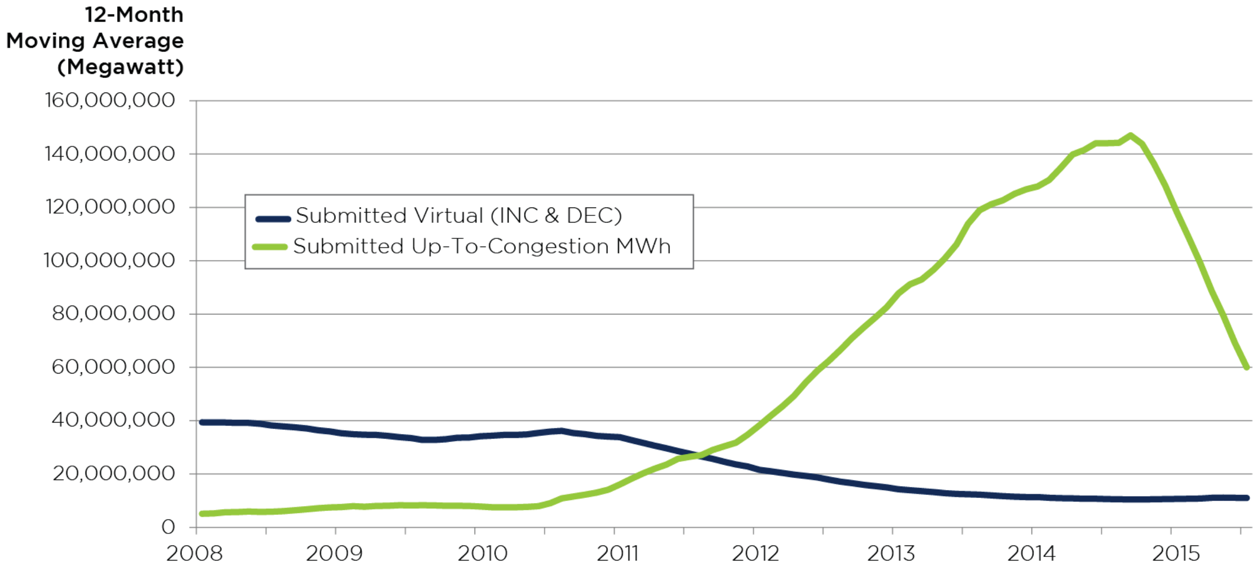
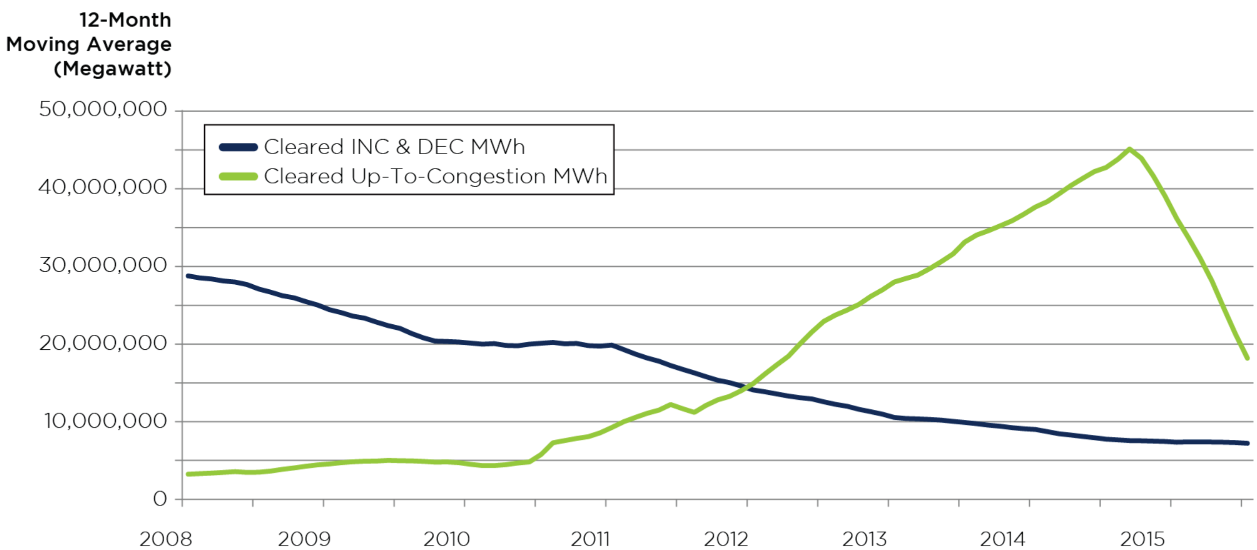


Figure 9. 12-Month Rolling Average of Cleared Virtual Transactions



As stated in the section titled, *Brief Background on the Evolution of UTCs*, the UTC product has changed significantly over time which no doubt led to the significant increase in its popularity. The expansion of bidding points combined with the reduction in transaction costs via the removal of the transmission service reservation requirement has made the UTC transaction extremely low cost to those deciding to use it.

The migration to UTCs has shifted the virtual trading market from what was primarily an INC and DEC traded market to one that is now dominated by UTCs. The benefit of no uplift allocation that is currently afforded to UTCs is likely a significant driver of this behavior. Additional information is provided on this in the *Observed Bidding Strategies* section of this paper.

The significant change in the volume of submitted and cleared UTCs in September 2014 is due to an open FERC 206 proceeding regarding FTR forfeiture rules and, more significantly, the allocation of uplift to UTCs. The Order established a refund effective date of September 8, 2015, after which any virtual transaction (including INCs and DECs) would potentially be responsible for paying uplift based on a method that is yet to be determined. This creates a significant risk for UTC traders because, today, they are not allocated any uplift as those participants submitting INCs and DECs are. This risk has significantly decreased both the number of UTCs submitted and the associated MW volumes.

A common discussion with regard to virtual trading is that high volumes are indicative of the health of the market. While this may be true in some cases, this presumes that the market rules and incentives in place always guide virtual activity towards trades that are both beneficial to efficient operation of the market and profitable to the trader. The section titled *Observed Bidding Strategies* provides simple examples that show bidding behaviors that PJM has witnessed that are permitted by today's market rules but do not positively contribute to market efficiency or price or commitment convergence.

Virtual Transaction Volumes and Day-Ahead Market Solution Time

The time required to clear the Day-Ahead Market has become a critical topic since the issuance of FERC Order 809[4]. In addition to revising gas nomination deadlines on interstate pipelines, Order 809 requires RTOs and ISOs to review the timing of their resource commitment processes. The obligation for RTOs includes adjusting the Day-Ahead Market timing to ensure that those commitments are provided to generation owners in enough time to allow them to make gas nominations for the Timely deadline. More specifically, Order 809 requires,

> "each ISO and RTO within ninety days of the publication of a Final Rule in this proceeding to: (1) make a filing that proposes tariff changes to adjust the time at which the results of its Day-Ahead Market and reliability unit commitment process (or equivalent) are posted to a time that is sufficiently in advance of the Timely and Evening Nomination Cycles, respectively, to allow gas fired generators to procure natural gas supply and pipeline transportation capacity to serve their obligations; or (2) show cause why such changes are not necessary."

In response to the Order, PJM filed changes to its longstanding Day-Ahead Market timeline that included moving the gate closure for bid and offer submissions from 12:00 p.m. to 10:30 a.m. PJM also committed to change the time of the publication of the Day-Ahead Market results from 4:00 p.m. to no later than 1:30 p.m. These changes will result in a decrease in the Day-Ahead Market clearing window from four hours to three hours.

[4] http://www.ferc.gov/whats-new/comm-meet/2015/041615/M-1.pdf

To achieve the reduction in the Day-Ahead Market clearing time PJM has primarily focused on technology enhancements. However, PJM believes that technology should not be the sole focus to improve the Day-Ahead Market solution time. The market rules that govern the set of viable bids and offers that can be submitted into the Day-Ahead Market can increase both the complexity and time required to clear the market. Thus market rules should be investigated as a potential area to improve Day-Ahead Market clearing times.

With respect to virtual transactions, both simple transaction volume and unique transaction volume are significant contributors to the complexity of the Day-Ahead Market solution and solution time. Simple transaction volume can be thought of as total number of virtual transactions at any location for INCs and DECs or with any source and sink for UTCs. For example, 1,500 MWh of additional DECs at Zone X only would be an increase in simple volume. Unique transaction volume can be thought of as additional transactions with different locations for INCs and DECs or sources and sinks for UTCs.

Increases in simple transaction volume can negatively affect data transfer times because of increases in the information that needs to be moved from one system to another. It can also increase solution complexity because it can cause transmission constraints to bind which further complicates the Day-Ahead Market and thus requires additional processing time. However, because those transactions are submitted at the same location, the ability for multiple different constraints to bind because of increases in simple volume is relatively small.

Unique transaction volume has an even more significant effect on the solution time of the Day-Ahead Market. Unique transaction volume is more impactful in terms of both solution time and complexity because it creates additional injections and withdrawals at different locations on the system and increases the number of transmission constraints that need to be controlled. Additional transmission constraints require additional controlling actions to be taken and, therefore, increase the complexity of the solution. As the complexity of the Day-Ahead Market solution increases, the solution scales exponentially, not linearly. The exponential impact is caused by the less efficient computational methods required to solve the increasingly complex problem.

To minimize the added complexity resulting from general transaction volume PJM has implemented a soft cap of 3,000 UTC transactions per market participant. PJM enforces the soft cap only when it experiences performance issues that could be mitigated by reducing the UTC volume.

This cap only indirectly limits unique transaction volume. However, the unique transaction volume issue can be addressed directly by reducing the number of available trading locations. The direct approach to limiting unique transaction volumes would reduce the number of different locations where virtual transactions can inject and withdraw on the system as well as the number of different transmission constraints encountered in the Day-Ahead Market. The reduction in the number of transmission constraints would reduce solution complexity and improve overall solution times.

Observed Bidding Strategies

All of the strategies contained within this section are possible within the existing PJM market rules. PJM believes that these types of trades, while profitable, do not add value to the market commensurate with the revenues collected by them. Thus, to the greatest extent practicable, where the rules or market operations cannot be changed without compromising more fundamental objectives (such as system reliability), the optimal approach to resolving these kinds of problems is simply to eliminate the opportunity for inefficient trading. Such an approach avoids enforcement uncertainty as well as legal and policy debates as to whether participants who follow market rules can nonetheless manipulate markets. Rather than prosecuting participants after the fact for exploiting opportunities left open by market design and operations, certain circumstances can be defined to prevent virtual trading where such trading can reasonably be assumed to provide little or no efficiency value to the market.

Small Positions on Low-Risk Paths

This strategy is observed exclusively with UTCs and is characterized by taking very small low-risk, positions in the Day-Ahead Market over a number of days and weeks and waiting for a particular path to bind in real time consistent with the flow direction of the UTC in the Day-Ahead Market.

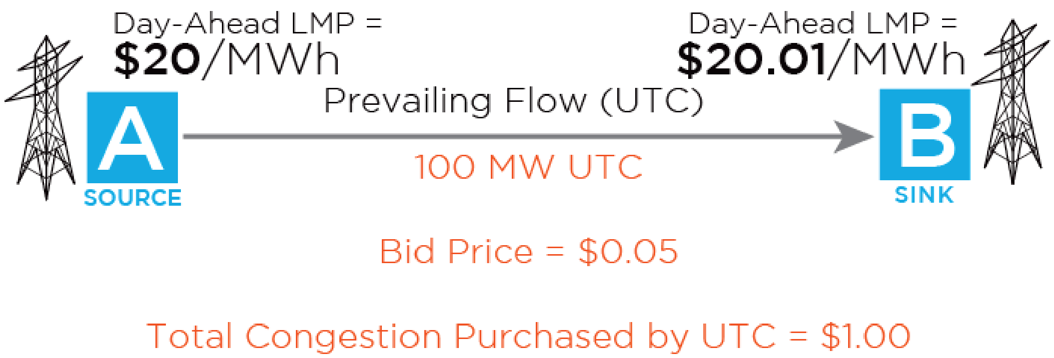
In this strategy, large volumes of UTCs are submitted throughout the system with very small price spreads of typically plus or minus $1.00/MWh or less. The large volume of UTCs submitted loads the transmission system causing a multitude of constraints in the Day-Ahead Market at very low shadow prices due to the low offer prices of the UTCs that are marginal on those paths. In real time, any price spread between the source and sink points that is in the same direction and of greater magnitude than what was purchased in the Day-Ahead Market now makes that UTC, as well as others in the same situation, profitable.

From the perspective of the market participant making this trade, this type of strategy provides many benefits with very low risk.

1. The position in the Day-Ahead Market can be taken with a very small monetary obligation.
2. Under the current rules, UTCs are not allocated uplift and therefore there is no risk that an allocation of uplift will make the transaction unprofitable.
3. There is a very low probability that the path binds in the opposite direction causing the transaction to lose money.

The third point above is important. The flow direction on a facility is based on the physics of the transmission system and is not a random variable. Therefore, absent topology changes in the area (which PJM posts) or uncommon weather patterns, the probability that the flows on a given facility change direction and do so to the extent that there is congestion opposite the flow of the UTC, is extremely small. The extremely low probability of this occurring combined with the first two points makes this a very common bidding strategy. The example below illustrates this strategy numerically.

Figure 10. Example of Low Risk UTC Position – Day-Ahead Market



Assume there is a 100 MWh UTC bid in on the path from A to B in the Day-Ahead Market. This UTC is submitted with a bid price of $0.05/MWh. This UTC will clear in day ahead any time the spread between A and B is less than or equal to $0.05/MWh. In this example, assume that spread is $0.01/MWh so that the UTC clears. The Day-Ahead Market settlement for the UTC in this hour would be a charge for the 100 MWh cleared from A to B, times the difference of $0.01/MWh between those two points, or $1.00. If this bidding strategy is put in place every hour of the day for a week with no congestion on that path or a neighboring one in real-time, absent administrative fees, the financial trader ends up spending only $168 in total (100 MWh * $0.01/MWh * 24 hours per day * 7 days per week).

As stated before, if the path being bid by the financial trader binds in real-time in the direction of A to B, the UTC will be profitable because the position taken in the Day-Ahead Market is so small. In the outcome shown below, there is congestion in real time between points A and B. In this case, the price at point B is $50/MWh and the price at point A is $10/MWh. For this given hour, the UTC profits $4,000 (100 MW * ($50/MWh - $10/MWh)).

Figure 11. Example of Low Risk UTC Position – Real-Time Market

PJM's opinion is that this bidding behavior, while permitted by today's market rules, does not provide the type of convergence sought through the inclusion of virtual transactions in the market. The position taken by the financial trader in the Day-Ahead Market is not significant enough to influence the commitment and dispatch of resources in the Day-Ahead Market such that the resulting commitment matched the controlling actions taken by PJM system operators in real time to manage congestion. Additionally, if positions like this are taken over multiple days or weeks, as PJM has observed, the relatively small impacts to other market participants due to the additional congestion in day ahead grow larger. Finally, when the constraint does bind in real time, the UTC has not provided any material convergence because clearing it only resulted in a day-ahead price spread of $0.01/MWh whereas the real-time split was $40/MWh.

In this example the impacts appear small when viewed in isolation but they can increase depending on the size of the position taken by the UTC and the amount of time over which it is not profitable. Because the risk associated with the bid is so low, the financial trader can afford to take the position over a significant period of time which increases the chances that the trader will have taken the position in Day-Ahead Market if the constraint ever binds in real time. When the transaction is profitable, the revenues paid come from balancing congestion and the marginal loss surplus. Because the UTC takes injection and withdrawal positions in the Day-Ahead Market, any difference between the energy component of LMP nets to zero. For example, if the energy component of LMP in day ahead was $5/MWh higher than real time, the injection portion of the UTC would make a $5/MWh profit whereas the withdrawal end would lose $5/MWh. As a result, the credits paid to UTCs when profitable come purely from congestion and marginal losses because they are different across the system. Large volumes of transactions of this type can significantly impact the funding in these areas.

Below is a histogram and accompanying chart showing the bidding activity for UTCs. As shown in the graphic below, despite the +/- $50/MWh bid cap on UTC trades, more than 95 percent of UTCs offered into the market are at a price between +/- $10/MWh. Further, more than 72 percent of all UTC bids are between +/- $2/MWh and more than half of the total activity falls between +/- $1/MWh. These types of bids are indicative of the low-risk positions that can be extremely lucrative without adding commensurate value to the market.

Figure 12. UTC Activity by Offer Price 2012/2013 Through 2014/2015

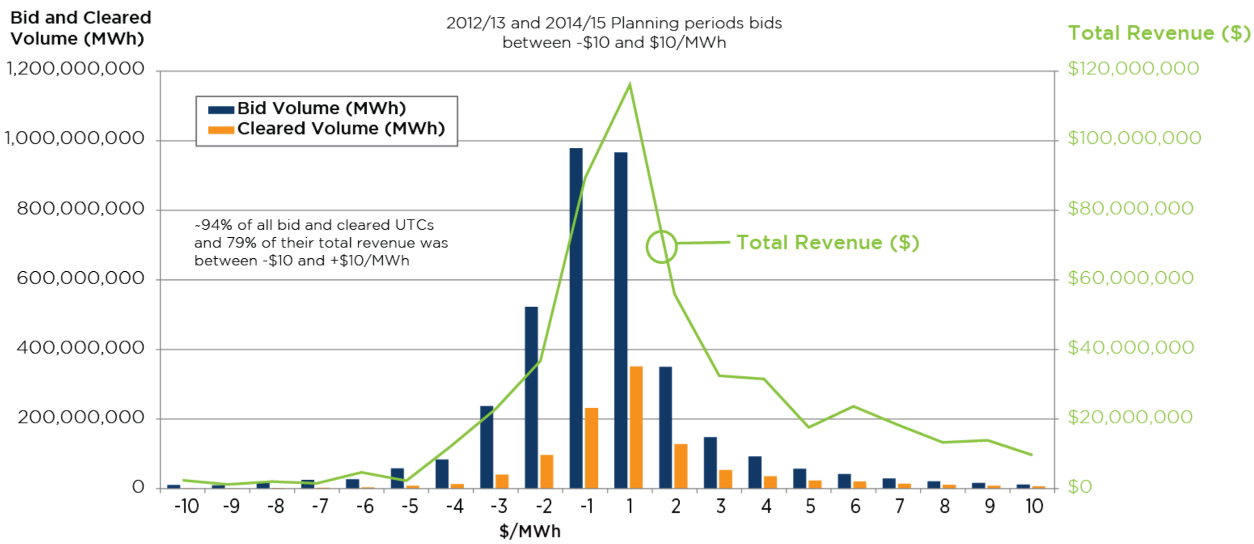


Table 19. UTC Volumes and Revenues by Offer Price

Price Group	Bid Volume (MWh)	Cleared Volume (MWh)	Total Revenue ($)	Bid Volume (% Total)	Cleared Volume (% Total)	Total Revenue (% Total)
Between $1/MWh and -$1/MWH	1,944,017,063.8	583,234,516.0	205,399,911.0	50.1%	51.1%	32.0%
Between $2/MWh and -$2/MWh	2,817,091,856.7	808,596,221.3	298,096,610.1	72.6%	70.9%	46.5%
Between $10/MWh and -$10/MWh	3,705,847,375.1	1,055,814,343.7	508,025,079.0	95.4%	92.5%	79.2%

Modeling Discrepancies

Another strategy PJM observes involves entities using UTCs to extract revenues from the market arising from modeling discrepancies between PJM's day-ahead and real-time models. While INCs and DECs could be used to enact this strategy, they are not typically used in these cases because the UTC presents a much lower risk option because its energy positions net to zero and it receives no uplift allocation. These attributes make the UTC extremely attractive.

During the process of solving the Day-Ahead Market and calculating real-time LMPs, PJM encounters "dead buses". A dead bus is completely disconnected from the system due to the topology surrounding that bus. Typically these are caused due to scheduled transmission outages. Because the bus is completely disconnected from the system, PJM cannot calculate an LMP for that bus as it does for all other connected buses. The dead bus scenario is addressed differently in the day-ahead and real-time technical systems.

In the day-ahead system, the dead bus is reconnected to the system so that virtual bids submitted at the dead bus can still be cleared. This method ensures that, even though a bus is dead, it remains a valid trading point. Once the bus is reconnected in day ahead, its price is reflective of the path through which it was reconnected to the system. In real time, there are no virtual bids to clear so the bus remains dead. In order to determine a price for the bus, the price from the nearest electrically equivalent node is used as a replacement for the dead bus.

Under most scenarios, these two methods produce prices at the dead bus that are electrically equivalent to each other. However, there are times when prices can deviate. When the discrepancy occurs in the PJM model, it becomes a focal point to attract opportunistic virtual transactions and creates a profit stream that provides no efficiency to the market.

Market participants do not have visibility into the logic by which dead bus situations are resolved in the day-ahead and real-time models. Therefore, market participants are likely to identify modeling discrepancies such as the one described above by analyzing the day-ahead and real-time nodal prices in a constrained area. If there are buses that are priced in the opposite direction relative to a reference point, it may be indicative of a location where arbitraging the potential price differences would be profitable.

For example, assume that Western Hub is the reference point and a market participant has noticed over several days that the price of node A is less than Western Hub in the Day-Ahead Market and higher than Western Hub in real time under the same congestion pattern.

Table 20. Western Hub and Node A Pricing During Modeling Discrepancy

Node	Day-Ahead LMP	Real-Time LMP
A	$58.00/MWh	$22.00/MWh
Western Hub	$30.00/MWh	$36.00/MWh
Payoff	$28.00/MWh	$14.00 /MWh

Once this pricing profile has been noticed, a market participant may take a number of actions to create a profit. One example is a counterflow UTC from node A to Western Hub. For a 100 MWh counterflow UTC, the market participant is paid $280 (100 MWh * ($58/MWh - $30/MWh)) in the Day-Ahead Market to take the position against prevailing congestion. In real time, however, the prices are in the opposite direction such that the counterflow UTC profit increases in real time by $140 (-100 MWh * ($22/MWh - $36/MWh)).

Table 21. Settlement of UTC

UTC Settlement	Payoff
Day-Ahead	$280
Real-Time	$140
Total	$420

In this example, the market participant, while potentially unaware that the observed price profiles were the result of a modeling discrepancy, identified the anomaly and was able to profit from it. However, there was no ability for the market participant to converge prices in the Day-Ahead Market closer to real time because the cause of the price differentials was a modeling discrepancy. As in the prior example, the product typically used in this practice is a UTC and therefore the revenues to the profitable UTC come from balancing congestion and the marginal loss surplus. The market participant may not know that a modeling discrepancy is the cause of the issue, but rather merely observes the consistent price differences and submits virtual transactions that it believes will be profitable if the differences persist. Therefore, the participant may not knowingly be exploiting the modeling discrepancy. However, because the revenue extracted from the market by the participant that engages in such a strategy is collected at the expense of other market participants with no positive impact on the efficiency of the market operation, PJM believes that the opportunity to profit from such discrepancies must be minimized to the greatest extent possible.

Virtual Trading at Nodes with no Physical Settlement

The next two examples illustrate undesirable market implications of having virtual transactions submitted and cleared at a nodal level at buses where there is no physical settlement. PJM's current market rules allow these transactions to occur and so the examples provided in this section are not intended to reflect bidding strategies that PJM considers to be market manipulation. They show the outcome of legitimate trading activities under today's rules that do not contribute to increasing the efficiency of the market operation.

Implications to the Zonal Definition

Today, INCs and DECs are able to be bid or offered at all hubs, zones, aggregates and individual nodes for which PJM posts a price. UTCs may be submitted at any source and sink combination that meets the following criteria set forth in Section 1.10.1A(c-1) of Attachment K of the Tariff.

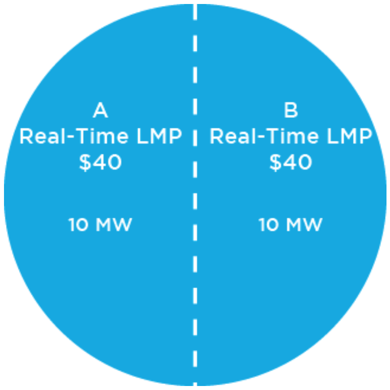
1. The node is part of the historic set of eligible nodes that were available as sources and sinks for interchange transactions on the PJM OASIS.
2. The node is not on a load bus that is less than 69 kV.
3. The node is not connected to a generator of less than 100 MW.
4. The node is not part of a set of nodes determined by PJM to be electrically equivalent to another node on the system.

As of August 1, 2015, there were 11,295 biddable nodes for INCs and DECs and 437 nodes that are eligible source and sink points for UTCs. Of the 11,295 biddable nodes for INCs and DECs, 86.3 percent are nodes where there is no settlement of physical assets. Of the 437 eligible source and sinks for UTCs, 29.3 percent are nodes where there is no settlement of physical assets. Of the total 11,390 posted prices by PJM, only 13.6 percent actually have a physical settlement associated with them.

When virtual bids are cleared at points or sets of points where there are no physical settlements, it can create deviations in the power flow modeling of the Day-Ahead Market and ultimately the commitment, dispatch and pricing in the Day-Ahead Market compared to what actually occurs in real time. Under today's rules, INCs and DECs are allocated an uplift charge for the energy deviation they create between the Day-Ahead Market and real time, but it is important to fully understand the implication of clearing an INC, DEC or UTC at the nodal level.

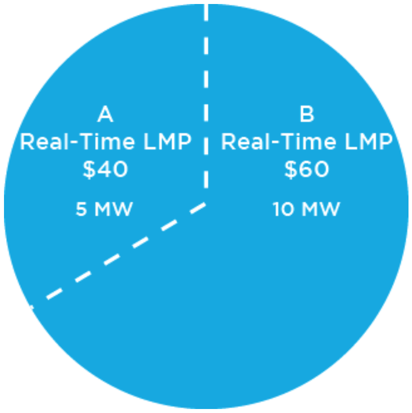
For example, consider load zone X in PJM composed of two pricing nodes, A and B, which each compose 50 percent of the zonal definition. The definition of a zone has several implications to the market and dispatch solutions. First, it determines the allocation of bids placed at that level to the individual buses for the purpose of power flow analysis. If there is a 20 MW fixed demand bid placed at this specific zone, for the purpose of solving the power flow, 10 MW of load would be placed at each of nodes A and B because of the fifty-fifty split in the definition. The second impact is the price calculation. The 50/50 split in load zone X between nodes A and B means that the zonal price for zone X will be composed of 50 percent of the price from node A and 50 percent from node B. Zonal definitions in the Real-Time Market in PJM are based on the load weighted average of the load buses in each zone. In the Day-Ahead Market they are based on the definitions used from a recent similar day in real time. This is done to ensure that the allocation of demand cleared in the Day-Ahead Market is done consistent with what was observed in real time.

Figure 13. Load Zone X Based on Assumed Load Distribution - 50/50 Split



If a market participant submits an INC, DEC or UTC that sources or sinks at zone X, the injection or withdrawal associated with that transaction is allocated in an equal share to nodes A and B. For a 100 MWh DEC at zone X, 50 MWh would appear at each of nodes A and B. However, if a 5 MWh INC was offered and cleared at node A only in the example above where there was a 20 MWh fixed demand bid at zone X, there would be some adverse implications. This would create a net load of 5 MWh at node A and 10 MWh at node B because the 5 MWh injection due to the INC at node A would net out of the load created by the fixed demand bid. This drives the day-ahead allocation of load within the zone away from what is anticipated in real time and consequently the surrounding transmission line flows away from the initial zonal model chosen from a similar day in real time. The cleared 5 MWh INC at node A has effectively changed the zonal definition used for the distribution of load to be 33 percent at node A and 67 percent at node B. This is different than the description used to mimic the real-time load distribution and is inconsistent with the day-ahead zonal LMP calculated for zone X which still uses the 50-50 split.

Figure 14. Load Zone X with Cleared INC at Node A – 33/67 Split



This transaction will be profitable any time the difference between the Real-Time LMP for node A is greater than the Day-Ahead LMP in excess of the uplift rate charged to the INC offer. Regardless of whether or not the bid is profitable, it has caused a difference between the distribution of load in zone X that PJM believes will occur in real time and what has cleared day ahead in a way that be cannot be replicated in real time.

This example shows several undesirable outcomes of an INC offer cleared at a nodal level. Similar examples can be constructed for DEC bids and UTCs as well.

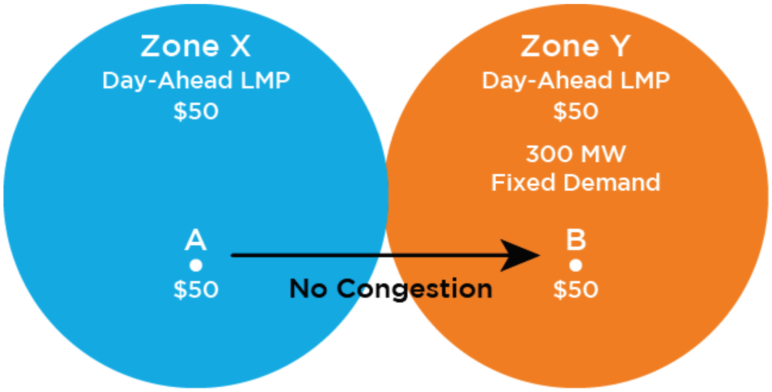
1. The cleared INC changes the zonal definition for load distribution implemented by PJM to ensure that the cleared demand in the Day-Ahead Market follows the load allocations observed in real time.
2. As a result of #1, the INC changes transmission flows inconsistent with the patterns observed by PJM in real time and embedded in the zonal definition. This potentially impacts congestion patterns, resource commitments, market-clearing prices, uplift amounts and FTR funding.
3. As a result of #1, the day-ahead zonal load distribution and the zonal LMP calculation are not done with a consistent definition because the INC has changed the net withdrawal at node A.

Congestion Patterns Inconsistent with Day-Ahead Market Demand Levels

In addition to a creating a zonal load distribution that is inconsistent with the calculation of the zonal LMP, permitting virtual transactions at individual nodes can have other implications. The scenario below shows a potentially constrained transmission path, A-B, between zones X and Y. This example uses a constraint between two zones for simplicity but it can occur with constraints wholly contained within a zone as well. Additionally, the virtual transaction used in the example is a DEC although similar examples can be created with INCs and UTCs.

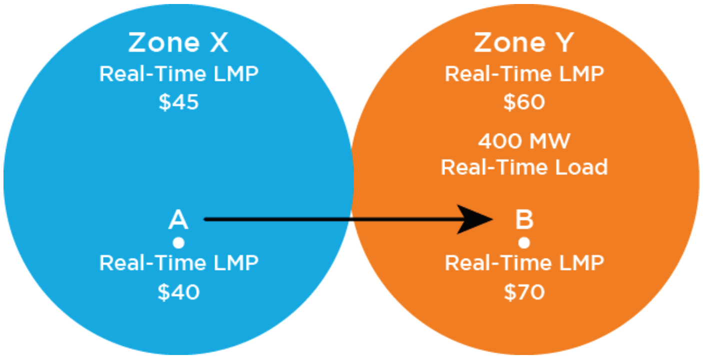
In the Day-Ahead Market, constraint A-B does not bind causing a uniform LMP of $50/MWh between zones X and Y. There is a fixed-demand bid at zone Y of 300 MWh that settles in the Day-Ahead Market for $15,000 ($50/MWh * 300 MWh).

Figure 15. Day-Ahead Path A to B Between Zones X and Y



In real time, the load in zone Y is now 400 MWh. The additional load zone Y has now caused congestion on path A-B such that the Real-Time LMP at A is $40/MWh and at B it is $70/MWh. The congestion also increases the zonal LMP of zone Y to be $60/MWh. The resulting balancing settlement for the load in zone Y would be $6,000 ($60/MWh * 100 MWh).

Figure 16. Real-Time Congestion on Path A to B



As a result of underbidding load in the Day-Ahead Market, the LSE of zone Y is able to procure its load at a discounted rate to what it would have had to pay in real time. This scenario, as illustrated above, provides an opportunity for virtual bidding to profit by converging the Day-Ahead Market and Real-Time Markets. Focusing in on the use of a DEC, a market participant can either submit a DEC at zone Y or at some individual node at the receiving end of the constraint (in this example use node B) in order to profit from converging the markets.

Based on the real-time clearing it is evident that node B has a higher distribution factor on constraint A-B than zone Y does because its price increases by more than zone Y's does when the path is constrained. Assume in this case zone Y's distribution factor on constraint A-B is 20 percent and node B's is 40 percent. The relationship between these distribution factors means that a DEC at the zone will have to be twice as large as a DEC at B to impose the same flow on A-B. In this example, a 100 MWh DEC at zone Y or a 50 MWh DEC at node B would create similar congestion patterns between day ahead and real time and push day-ahead and real-time prices closer together. These different options have vastly different impacts on the commitment and dispatch of the resources in the Day-Ahead Market.

In the case where the DEC is submitted at B, congestion is created on path A-B, the prices between day-ahead and real-time converge at that point and the DEC makes a profit. However, the DEC at B does not address the amount of underbid load in the Day-Ahead Market that is causing the original divergence in congestion. Notwithstanding the location differences explained in the previous section, the 50 MW DEC at node B is 50 MWh short of the ideal activity that would converge both the prices and the resource commitments between day ahead and real time. Essentially, if the DEC at node B clears, the Day-Ahead Market load is still underbid by 50 MWh which means that PJM has to now schedule additional resources in the reliability commitment to meet the real-time needs of the system. If the DEC at zone Y clears, it requires more MWs to create the same amount of congestion and price convergence. The additional MWs required at the zone cover the difference in underbid load in zone Y and therefore the scheduling of resources in the Day-Ahead Market solution is also improved over the solution with the DEC at B.

Another outcome shown in the previous example is that allowing virtual transactions to occur at some locations, in this case an individual bus within a zone, can result in congestion levels in the Day-Ahead Market that are inconsistent with the system's level of cleared demand. The prior example shows that in real time, 400 MWh of load in Zone Y results in congestion on the path A-B. However, as a result of the DEC at node B, the same congestion is created in the Day-Ahead Market at a cleared demand level of 300 MWh. This phenomenon can be created in the opposite direction as well where there is more cleared demand in the Day-Ahead Market than load in real time yet congestion patterns are the same as a result of nodal virtual transactions relieving congestion. Both cases can result in inefficient resource commitment in the Day-Ahead Market. In the scenario provided in the example, PJM may commit resources in the Day-Ahead Market to resolve the congestion created by the DEC when what is really needed are resources scheduled to both control the congestion and serve the load that was underbid in Zone Y. In the second scenario where there is less congestion than the cleared demand levels in the Day-Ahead Market would otherwise reflect, PJM may commit resources to serve the additional day-ahead demand but not those that would be effective to resolve the additional congestion in real-time. In both cases, the result of the inefficient commitments can be price divergences between the Day-Ahead and Real-Time Markets in addition to uplift.

Recommended Improvements to Virtual Trading

Restated below are the recommendations put forth by PJM regarding virtual trading. The goals of these proposed rule changes are to maintain the benefits added to PJM's markets by virtual trading, eliminate opportunities for inefficient trades to profit in the market, and level the allocation of uplift across all virtual transactions.

Align the eligible trading points for INCs and DECs with nodes where either generation, load or interchange transactions are settled, or at trading hubs. This would include generator buses where active generators exist, load buses where load is settled nodally, load zones, interfaces and trading hubs.

The intent of this change is to better align the use of INCs and DECs with the physical nature of the Real-Time Market while preserving the ability for such instruments to be used at trading hubs to facilitate longer-term hedges. Under today's rules, INCs and DECs can be placed at nodes where there is no other settlement such as individual load buses. While these types of transactions may be profitable based on differences between the Day-Ahead and Real-Time Markets, they can result in transmission flows and load distributions that are inconsistent with physical reality of the system and potentially result in resource commitments in the Day-Ahead Market that do not align with the system needs in real-time. They may aide in price convergence at the specific node, but it is at a location where there is no other settlement and therefore no real change in the incentives to other market participants.

PJM believes that it is extremely important that the Day-Ahead Market produce a resource commitment that closely mimics the set of resources required to operate the system in real time. Allowing INCs and DECs at load buses that can change the load distribution of a zone in a manner inconsistent with PJM's expectation of the real-time load distribution only makes achieving that goal more difficult and more costly. Additionally, INCs and DECs at individual load buses can create congestion patterns inconsistent with the load levels in the Day-Ahead Market. This can cause the Day-Ahead Market to commit resources to control congestion in a zone when what really is needed are additional resources to cover underbid load or the decommitment of resources due to overbid load.

Additionally, this change will reduce unique transaction volume which will improve Day-Ahead Market solution times. (See *Virtual Transaction Volumes* and *Day-Ahead Market Solution Time*).

Alter the biddable locations for UTCs to generation buses as sources only, trading hubs, load zones and interfaces.

For the same reasons as stated for INCs and DECs, in addition to others contained within this paper, PJM believes that the available bidding nodes for UTCs should be changed. In addition to hubs, zones and interfaces, PJM also proposes to allow generator buses as biddable UTC points but only as the source point of the transaction. Permitting UTCs at interfaces, hubs and zones is intended to continue to permit UTC trading but remove their ability to be used in ways that do not lead to market efficiency. Because these activities are typically enacted nodally, removing individual nodes will remove much of this ability. Notwithstanding the foregoing, PJM does propose to permit UTCs to be submitted with active generation buses as the source point only. This change is proposed to allow market participants trying to hedge generation or load against real-time congestion a method to do that.

Given the volume of UTC transactions, reducing the bidding points would significantly reduce the number of unique UTC transactions and significantly improve Day-Ahead Market performance.

Allocate uplift to UTCs consistent with INC and DEC transactions. Currently, UTCs do not face a similar uplift charge as INCs and DECs, which has led to a significantly greater volume of UTCs as compared to INCs and DECs.

The incentives created by the inconsistent allocation of uplift between UTCs, and INCs and DECs can be seen through the specific transaction volumes PJM has seen over the last few years. Currently, UTCs account for approximately 80 percent of all virtual transaction activity and collect more than 81 percent of the total virtual transaction revenues. UTCs have a much smaller risk profile than INCs and DECs due to the lack of allocation of uplift and no exposure to energy price risk between day ahead and real time. Allocating UTCs uplift consistent with INCs and DECs would better align the risk profiles of the transactions as they pertain to fees and help level the uneven playing field that exists today.

PJM believes the allocation of uplift to UTCs is a critical market design change that must be made to remove the competitive advantage afforded to UTCs today.

PJM is proposing these suggested market rule changes to stimulate discussion within the stakeholder process. The goal of this discussion is to retain all of the positive aspects that virtual transactions bring to the market while removing the bulk of the issues that they can create when used inefficiently under the existing rules.

APPENDIX A – Usage Statistics

Provided below are some high level statistics regarding the usage and profitability of virtual transactions in recent history. Table 22 shows the total cleared MWh for all virtual transaction types for each of the last three Planning Years and the percentage of the total cleared virtual transaction volume for which they accounted. Considering a cleared UTC as a single transaction as opposed to a paired INC and DEC, they average 79 percent of the total cleared virtual transaction activity over the period with DECs following at 12.5 percent and INCs at 8.5 percent.

Table 22. Cleared Virtual Transaction Volumes and Percentage of Total Virtual Transaction Activity by Year (MWh)

Planning Year	DEC	INC	UTC	TOTAL	DEC	INC	UTC
2014/2015	51,458,286	36,195,902	255,036,657	**342,690,845**	15.0%	10.6%	74.4%
2013/2014	58,855,754	36,391,984	506,553,192	**601,800,930**	9.8%	6.0%	84.2%
2012/2013	70,732,526	49,661,232	379,581,312	**499,975,069**	14.1%	9.9%	75.9%
TOTAL	**181,046,566**	**122,249,118**	**1,141,171,160**	**1,444,466,845**	12.5%	8.5%	79.0%

UTC volumes dropped significantly in September 2014 (month four of the 2014/2015 Planning Year) due to an open 206 proceeding that the FERC initiated regarding the allocation of uplift to virtual transactions. As a result, roughly nine of the 12 months in the 2014/2015 Planning Year saw an on-average 78 percent reduction in UTC volume from what it was in the first three months of the Planning Year. In cleared MWh, there was an average drop in UTC volume from 1.6 million MWh/day during the period of June 1, 2014 through September 8, 2014 to 0.36 million MWh/day from September 9, 2014 through May 31, 2015. Despite this significant reduction, cleared UTCs still account for almost 75 percent of the total cleared virtual transaction volume in that year.

As shown in Table 23, the revenues accumulated by UTCs far outweigh any other virtual transaction over the past three years. On-average over the last three planning years they collect just over 81 percent of the total credits paid to all virtual transactions which aligns with them accounting for about 80 percent of the total volume. Despite the reduction in volumes in the 2014/2015 Planning Year, UTC revenues still account for over 75 percent of all revenues paid to virtual transactions.

Table 23. Virtual Transactions Gross Revenues by Planning Year

Planning Year	DEC Payoff	INC Payoff	UTC Payoff	Total Payoff	DEC	INC	UTC
2014/2015	$13,633,746	$50,109,473	$195,337,617	**$259,080,836**	5.26%	19.34%	75.40%
2013/2014	($61,805,475)	$92,103,332	$305,225,638	**$335,523,495**	-18.42%	27.45%	90.97%
2012/2013	$32,748,471	$20,715,093	$140,840,798	**$194,304,362**	16.85%	10.66%	72.48%
TOTAL	**($15,423,258)**	**$162,927,898**	**$641,404,054**	**$788,908,693**	-1.96%	20.65%	81.30%

Table 24 shows the average gross payoff per cleared MWh of each transaction type for each year. On a per cleared MWh basis, INCs are the most profitable virtual transaction whereas DECs are the least profitable from a gross perspective.

Table 24. Virtual Transaction Gross Payoff per Cleared MWh by Planning Year

	Gross Payoff Per Cleared MWh		
Planning Year	**DEC**	**INC**	**UTC**
2014/2015	$0.26	$1.38	$0.77
2013/2014	-$1.05	$2.53	$0.60
2012/2013	$0.46	$0.42	$0.37
AVERAGE	**-$0.11**	**$1.44**	**$0.58**

During the 2014/2015 Planning Year, the average Day-ahead Operating Reserve Rate was about $0.13/MWh while the Balancing Operating Reserve Rate for RTO deviations was about $1.20/MWh. This means that absent locational adders, each DEC paid $1.33/MWh in deviation charges and each INC paid $1.20/MWh. Because UTCs are currently not allocated uplift, their profitability is not impacted by these rates. If these uplift rates are subtracted from the gross profitability rates in Table 24, DECs become unprofitable in 2014/2015 and the net profitability for a cleared INC drops to about $0.18/MWh. On a net basis, the UTC becomes by far the most profitable transaction at $0.77/MWh due to the lack of uplift charge.

In addition to the aforementioned uplift charges, each virtual transaction is allocated a share of the administrative fees to maintain PJM's technical systems. This fee is allocated on a per transaction basis and is uniform across all market transactions.

Table 25 shows the usage and payoff of virtual transactions by sector. The data below shows that the Other Supplier sector dominates virtual transaction activity and also collects by far the most revenues. With the exception of the Transmission Owner Sector, the revenues and the virtual transaction volumes follow each other.

Table 25. Virtual Transaction Usage and Revenues by Sector – June 1, 2013 through May 31, 2015

Sector	Percentage Of Total Cleared MWh	Percentage Of Total Payoff
Other Supplier	87%	111%
Transmission Owner	8%	-14%
Generation Owner	4%	2%
Electric Distributor	1%	1%
	100%	**100%**