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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. ER18-88-000
Proposed Revisions To Reduce Bidding Points for 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 reduce the number of bidding points at which Virtual Transactions[2] may be submitted by Market Participants. PJM respectfully asks the Commission to issue an order accepting these proposed revisions on or before January 16, 2018, with an effective date of January 16, 2018 which is more than 60 days from the date of this filing.[3]

[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] 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").

[3] While PJM's Members Committee approved the enclosed revisions on June 22, 2017, PJM delayed submitting this filing given the fact the Commission lacked a quorum between February 4, 2017 and August 10, 2017.

I. 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 allocating uplift 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 address concerns regarding how Virtual Transactions participate in PJM's markets.[4]

As will be described in more detail herein, the revisions proposed in this filing will align the eligible bidding locations for Virtual Transactions with areas where they can have the most significant market benefits while reducing opportunities for them to be used to profit from the market without adding commensurate value. Another significant benefit is that consolidating the number of eligible bidding locations for Virtual Transactions will reduce the complexity of the Day-ahead Energy Market and therefore the time it takes to solve it. This will result in better coordination between the electric and gas markets which ultimately results in better price formation in PJM's energy markets. Accordingly, for the reasons described herein, the proposed revisions are just and reasonable and should be accepted by the Commission.

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 physical power in the Real-time Energy Market. In PJM, Virtual Transactions include Increment

[4] 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)).

Offers ("INC"),[5] Decrement Bids ("DEC")[6] and Up-to-Congestion Transactions ("UTC").[7] Virtual Transactions can be used to arbitrage price differences between the Day-ahead Energy Market and Real-time Energy Market and hedge financial exposure from physical positions. This is accomplished by a Market Participant taking a financial position in the Day-ahead Energy Market by agreeing to buy or sell energy at a specific location, which position it then liquidates in the Real-time Energy market.[8]

Virtual Transactions can be a valuable component of a two-settlement market like PJM's, as 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 PJM's energy markets.[9] Overall, this enables Virtual Transactions to contribute to the efficient operation of the PJM energy markets, as they can assist in attaining efficient market

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[5] "Increment Offer" 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. INCs are a "supply side" or "energy-injection" transaction.

[6] "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.

[7] "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).

[8] Specifically, if the day-ahead price is higher than the real-time price, a trader would profit by submitting an INC to sell energy at the high day-ahead price and buy out of that position at the lower real-time price. Conversely, a DEC would make money if the real-time price is higher. UTC bids can be based on the prevailing flow direction where the UTC is buying a position on the Day-ahead Energy 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.

[9] *See, e.g.*, PJM Interconnection, L.L.C., *Virtual Transactions in the PJM Energy Markets*, at 2 (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).

outcomes and improving commitment and price convergence between the Day-ahead Energy Market and Real-time Energy Market. However, Virtual Transactions can have negative impacts on the market.[10] As discussed below, when used in certain ways, Market Participants of these transactions earn profit from the market without adding commensurate benefit, skew transmission flows and congestion patterns in a manner inconsistent with real-time system operations, and, in large volumes, can significantly degrade the performance of the Day-ahead Energy Market.[11]

II. NEED FOR REVISIONS

In October 2015 PJM published a whitepaper titled Virtual Transactions in the PJM Energy Markets that focused on providing education on the value of virtual transactions but also highlighting some concerns PJM has with the current rules that govern how these transactions can participate in the market. That document was written at the request of PJM stakeholders following much discussion at the Energy Market Uplift Senior Task Force ("EMUSTF") regarding the potential for reduced volumes of Virtual Transactions if they were allocated a higher amount of uplift than they are currently. While much of the focus of the discussion on the allocation of uplift at the EMUSTF focused on the UTC transaction, PJM's Virtual Transactions Whitepaper covered all Virtual Transactions and delved into different motivations and impacts of each Virtual Transaction, bidding behaviors, and the impact of allocating uplift differently across the transactions.

PJM's Virtual Transactions Whitepaper provided two general recommendations:

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

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

1. The allocation of uplift should be done consistently across Virtual Transactions.

2. The points at which Virtual Transactions can be submitted should align with points where the settlement of physical energy occurs or forward positions can be taken (i.e., trading hubs).

While the first recommendation is not in the scope of this filing, it has led to an untenable shift in the amount and distribution of Virtual Transactions in PJM that PJM and its stakeholders are attempting to correct in a sister filing submitted to the Commission concurrently with this filing. The second recommendation regarding eligible bidding locations for Virtual Transactions was added to the charter of the EMUSTF for further discussion and culminates with this filing.

As PJM discussed at length in the Virtual Transactions Whitepaper, PJM has concerns with the current eligible bidding nodes because it is unclear how Virtual Transactions at some locations can provide the theoretical benefits upon which Virtual Transactions were founded. Specifically, PJM believes that a Virtual Transaction such as an INC placed at a load bus in the Day-ahead Energy Market that results in a net injection in the Day-ahead Energy Market, cannot result in an increase in market efficiency, an improvement of the Day-ahead Energy Market commitment, or a mitigation of market power. The Virtual Transactions Whitepaper highlights these fundamental concerns but also calls out observed bidding phenomenon by Market Participants that while permissible under PJM's current rules and profitable for certain Market Participants, also do not add value to the market commensurate with the revenues collected by such Market Participants.[12] These occurrences include, but are not limited to: (i) taking very small, low-risk, positions in the Day-ahead Energy Market over a number of days and weeks and

[12] *See Id.* at 38.

waiting for a particular path to bind in real-time;[13] and (ii) bidding in locations where there is a systematic price difference between the Day-ahead and Real-time Energy Markets due to a modeling difference between the Day-ahead Energy Market and Real-time Energy Market.[14]

In the Virtual Transactions Whitepaper PJM recommended that "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."[15] With the consent and endorsement of an overwhelming number of PJM's stakeholders, PJM is taking such steps herein.

A. Problems with the Current Set of Eligible Nodes for Virtual Transactions

Generally speaking, 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 criteria set forth in Operating Agreement, Schedule 1, section 1.10.1A(c-1).[16] This difference in eligible bidding locations is a result of how these transactions have evolved over time but has significance beyond that. INCs and DECs have always been considered Virtual Transactions in PJM and have always been able to bid at locations where PJM posts a price. UTCs have a more confined set of eligible bidding locations because they were originally used as congestion hedges for real-time wheel transactions. The set of points that UTCs can bid at has been broadened over time through discussions and consensus

[13] *See Id.* at 38-41.

[14] *See Id.* at 41-42.

[15] *See Id.*

[16] Those criteria currently are "Step 1: Start with the historic set of eligible nodes that were available as sources and sinks for interchange transactions on the PJM OASIS. Step 2: Remove from the list of nodes described in Step 1 all load buses below 69 kV. Step 3: Remove from the resulting set of nodes from Step 2 all generator buses at which no generators of 100 megawatts or more are connected. Step 4: Remove from the results of Step 3 all electrically equivalent nodes." *See* Operating Agreement, Schedule 1, section 1.10.1A(c-1).

in the PJM stakeholder process. Additionally, because the UTC is a paired injection and withdrawal, it has different incentives than an INC or DEC, is a more complex transaction to assess mathematically, and therefore can have a more dramatic impact on Day-ahead Energy Market solution time.

As of this filing, , there were 11,727 biddable nodes for INCs and DECs and 418 nodes that are eligible source and sink points for UTCs. Of the 11,727 biddable nodes for INCs and DECs, 87.9 percent are nodes where there is no settlement of physical assets. Of the 418 eligible source and sinks for UTCs, 69.4 percent are nodes where there is no settlement of physical assets. Of the total 11,805 posted prices by PJM, only 12 percent actually have a physical settlement associated with them.

Although the Day-ahead Energy Market is commonly referred to as a financial market, it is extremely tightly linked to Real-time Energy Market system operations. The resources committed in the Day-ahead Energy Market set the initial resource plan for what will run in real-time. If the day-ahead resource commitment is not optimal, it can have a significant impact on real-time system operations and market results. In that sense, the Day-ahead Energy Market is far more than just a financial market. It is the scheduling process that PJM and other ISO/RTOs use to commit resources to serve load and maintain reliability the next operating day.

Virtual Transactions add value to the market when they fill the gap between how physical load and supply resources are represented in the Day-ahead Energy Market versus what actually occurs in real-time operations. For example, a DEC is profitable and adds value to the market when it increases the load in the Day-ahead Energy Market closer to what it would be in real-time. The same principle applies to an INC transaction where the INC seeks to push supply

in the Day-ahead Energy Market closer to real-time. This value to the market is increased when the INC or DEC occurs at the same location as the physical transaction it seeks to replicate. For example, assume the load in Zone Y is underbid by 2 MW in the Day-ahead Energy Market. From a scheduling, dispatch, and pricing perspective, it is intuitive that a cleared 2 MW DEC at Zone Y would produce the most desirable Day-ahead Energy Market results because it would result in a unit commitment and pricing profile that most closely replicates real-time operations. A cleared DEC at an individual node in Zone Y may, at a gross level, increase the load so that it matches real-time but it also skews transmission flows in a manner that is inconsistent with real-time. This can lead to congestion in the Day-ahead Energy Market that does not materialize in real-time and the commitment of resources day-ahead that are not the optimal set. This is because the 2 MW of load that was underbid was distributed across Zone Y, not at any one specific location.

Today PJM determines the distribution of load for a zone in the Day-ahead Energy Market by using the real-time load distribution for that zone from the same day the week prior. This is done to ensure load is allocated in a manner that represents a reasonable expectation of how load will manifest in real-time. Using this model gives the Day-ahead Energy Market the best opportunity to produce a unit commitment that will be efficient for real-time operations. Allowing Virtual Transactions at individual load buses that are part of a larger zonal definition undermines this distribution because it can shift transmission flows in a manner that is inconsistent with real-time operations. PJM believes that allowing Virtual Transactions at these locations does not provide value to the market because they shift that Day-ahead Energy Market solution further away from what is expected in real-time. A more detailed example of this is

provided in PJM's whitepaper in the section titled, "Virtual Transactions at Nodes with No Physical Settlement."

For the same reason, Virtual Transactions at other locations where they are currently allowed today – such as at pricing nodes where generators used to exist but have since retired – raise the question of how these transactions, when profitable, are helping converge the resource commitment, dispatch and prices closer to real-time. In real-time operations there will never be injections or withdrawals at those locations but Virtual Transactions in the Day-ahead Energy Market at those locations can create an injection or withdrawal in the Day-ahead Energy Market where it will not occur in the Real-time Energy Market. Additionally, PJM has another set of nodes, Extra High Voltage ("EHV") nodes, that are used to publish prices on the EHV system. These nodes are neither generation nodes or load buses and therefore will never have injections or withdrawals in real-time at those locations in real-time. These points are also eligible nodes for Virtual Transactions under todays rules and therefore can have net injections or withdrawals at them in the Day-ahead Energy Market but will never have them in the Real-time Energy Market.

The extremely broad set of eligible nodes for Virtual Transactions that exist today also expose PJM Market Participants to increased financial exposure due to discrepancies between the Day-ahead Energy Market and Real-time Energy Market network models. Discrepancies between the models can occur for various reasons despite PJM's best attempts to minimize them. A common model discrepancy that occurs is a difference between system topology between day-ahead and real-time in the area of a transmission outage. Something as simple as an inconsistent breaker status (open or closed) from the Day-ahead Energy Market to the Real-time Energy

Market can create a systematic difference between day-ahead and real-time prices that provide a revenue opportunity for Virtual Transactions without the ability to provide any convergence between the Day-ahead Energy Market and Real-time Energy Market. Because individual nodes are more highly impacted by modeling discrepancies than aggregated locations due to averaging, they are often locations where Virtual Transactions can profit. Profits collected by Virtual Transactions in these cases lead to additional costs for PJM members without any benefits. A more detailed example of this is provided in PJM's whitepaper in the section titled, "Virtual Transactions at Nodes with No Physical Settlement."

B. INC and DEC Trading Locations Should Be Aligned With Locations Where Energy is Physically Settled or Forward Positions can be Taken

Given the foregoing, PJM believes that it is extremely important to reform the bidding points eligible for Virtual Transactions such that the Day-ahead Energy Market produces a resource commitment that closely mimics the set of resources required to physically operate the system in real time. Thus, PJM proposes to align the eligible trading points for INCs and DECs with nodes where either generation, load or interchange transactions are settled, or at trading hubs where forward positions can be taken. These changes will drive direct competition between INCs and DECs and physical assets at locations where the injections and withdrawals created in the Day-ahead Energy Market by such Virtual Transactions are most likely to occur in real-time. Additionally, the continued ability to submit INCs and DECs at trading hubs where forward positions can be taken will continue to allow today's forward hedging practices to continue. These reforms will also remove much of the ability for such Virtual Transactions to be used in ways that do not clearly have the opportunity to provide the theoretical benefits on which they were founded.

C. UTC Trading Locations Should Be Limited to Trading Hubs, Load Zones and Interfaces

In the section of PJM"s Whitepaper on Virtual Transactions titled, "Differences Between INCs and DECs and UTCs," PJM identifies the different system impacts and incentives between UTCs and INCs and DECs. UTCs are a lower risk transaction than INCs and DECs because they are not exposed to changes in the energy component of LMP between Day-ahead and Real-time like INCs and DECs are. Additionally, UTCs profit based on the net position of the injection and withdrawal sides of the transaction rather than the price at a single point. As stated in that section of the whitepaper:

> 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.[17]

The outcome of this is that 90% of profitable UTCs create a divergence between the Day-ahead Energy Market and Real-time Energy Market on one end of the transaction. This is a unique property to UTCs that does not exist for INCs and DECs. As such, it changes the incentives for bidding UTCs and their impact on the market. Further, unlike the INC and DEC, there is no real-time equivalent to the UTC. A point-to-point transaction within the PJM pool does not exist and therefore it is unclear how the conditions created by a UTC in the Day-ahead Energy Market can ever be replicated in real-time. These are critical distinctions that PJM believes warrant a different consideration regarding bidding points.

Given the additional complexity presented by UTCs, the fact that they create a divergence in either the source or sink location in 90 percent of occurrences, the inability for the

[17] Virtual Transactions Whitepaper at 20.

transaction to consistently and accurately drive commitment, dispatch and pricing consistency between the Day-ahead Energy Market and Real-time Energy Market because the UTC has no real-time equivalent, PJM has proposed to allow UTC trading to occur at hubs, zones and interfaces and not at individual nodes. PJM believes this strikes the appropriate balance between allowing continued use of the transaction with mitigating the risks and potential adverse impacts associated with it.

D. PJM's Proposed Solution Has the Added Benefit of Reducing the Clearing Time of the Day-ahead Energy Market

In addition to the aforementioned benefits related to better aligning the Day-ahead Energy Market and Real-time Energy Market, reducing the amount of bidding points that Virtual Transactions can be submitted and cleared at will result in the additional benefit of reducing the amount of time it takes to clear the Day-ahead Energy Market, thus improving Day-ahead Energy Market performance.

The amount of time it takes to clear the Day-ahead Energy Market Commission was closely examined in Commission Order No. 809,[18] which looked to improve gas-electric coordination. Specifically, Order No. 809 required each RTO/ISO to propose "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."[19] In response to Order No. 809, PJM filed changes to its longstanding Day-ahead Energy Market timeline to: (1) change

[18] *Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities*, Order No. 809, 151 FERC ¶ 61,049 (2015) ("Order No. 809").

[19] *See Id.* at P 16.

the deadline for posting the results of its Day-ahead Energy Market from 4:00 p.m. to 1:30 p.m.; 12, and (2) change the deadline for submitting bids and offers for the Day-ahead Energy Market from 12:00 p.m. to 10:30 a.m.[20]

In order to reduce the time it has taken to clear the Day-ahead Energy Market, PJM has focused predominantly on technological changes to its software systems. However, by eliminating the UTC bidding points which create much complexity[21] but do not serve to help converge the Day-ahead Energy Market and Real-time Energy Market, PJM will be able to further reduce the clearing time of the Day-ahead Energy Market.

III. PROPOSED TARIFF REVISIONS

In order to effectuate the aforementioned reforms, PJM proposes the following revisions to Operating Agreement, Schedule 1, section 1.10.1A (c-2):

> (c-2) ~~The source-sink paths on which an~~ Up-to Congestion Transactions may only be submitted ~~are limited to~~ at hubs, Residual Metered Load and interfaces not described in Tariff, Attachment K-Appendix, section 2.6A(b). ~~those paths posted on the PJM internet site and determined by the Office of the Interconnection using the following criteria:~~
> ~~Step 1: Start with the historic set of eligible nodes that were available as sources and sinks for interchange transactions on the PJM OASIS.~~
> ~~Step 2: Remove from the list of nodes described in Step 1 all load buses below 69 kV.~~
> ~~Step 3: Remove from the resulting set of nodes from Step 2 all generator buses at which no generators of 100 megawatts or more are connected.~~
> ~~Step 4: Remove from the results of Step 3 all electrically equivalent nodes.~~ Increment Offers and Decrement Bids may be only submitted at hubs, nodes at

[20] *See PJM Interconnection, L.L.C.*, Compliance Filing Revising Certain Deadlines of the Day-Ahead Energy Market and Reliability Assessment Commitment in the PJM Open Access Transmission Tariff and Operating Agreement, Docket Nos. ER15-2260-000 and EL14-24-000, at 3 (Jul. 23, 2015).

[21] Because UTCs have a source and sink location that must both clear as opposed a single injection or withdrawal like an INC or DEC, they are more complex computationally more complicated than clearing a single INC or DEC. PJM currently allows 418 eligible source and sink points for UTCs. This allows for 87,153 different source sink combinations of UTCs – all of which can create different flows patterns in the Day-ahead Energy Market that impact congestion and losses in a different manner. This many combinations can materially degrade Day-ahead Energy Market Performance.

> which physical generation or load is settled, Residual Metered Load and interfaces not described in Tariff, Attachment K-Appendix, section 2.6A(b).

The described locations represent physical locations at which Virtual Transactions may be submitted. Moreover, interfaces described in Tariff, Attachment K-Appendix, section 2.6A(b) are interfaces between PJM and Balancing Authorities that are subject to special rules and procedures. These rules and procedures lead to an outcome where Virtual Transactions do not help converge prices of the Day-ahead Energy Market and Real-time Energy Market, meaning that Virtual Transactions should not be submitted at these specific interfaces just as they should not be submitted at locations where energy is not physically settled.

IV. STAKEHOLDER PROCESS

On April 27, 2017 the PJM Markets and Reliability Committee endorsed the proposed revisions to the Tariff and Operating Agreement described herein by sector-weighted vote with 4.07 out of 5.0 in favor of the proposal. On June 22, 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 5.0 in favor of the proposal.

V. PROPOSED EFFECTIVE DATE

PJM respectfully asks the Commission to issue an order accepting these proposed revisions on or before January 16, 2018, with an effective date of January 16, 2018. This date is more than 60 days, but less than 120 days from the date of the filing and is thus consistent with section 35.3(a)(1) of the Commission's regulations.

VI. CORRESPONDENCE AND COMMUNICATIONS

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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;

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

Attachment C – PJM Whitepaper on Virtual Transactions.

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,[22] 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

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

PJM Members and all state utility regulatory commissions in the PJM Region[23] 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.

Respectfully submitted,

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October 17, 2017

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

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)

1.10 Scheduling.

1.10.1 General.

(a) The Office of the Interconnection shall administer scheduling processes to implement a Day-ahead Energy Market and a Real-time Energy Market. PJMSettlement shall be the Counterparty to the purchases and sales of energy that clear the Day-ahead Energy Market and the Real-time Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a Generating Market Buyer's self-schedule or self-supply of its generation resources up to that Generating Market Buyer's Equivalent Load.

(b) The Day-ahead Energy Market shall enable Market Participants to purchase and sell energy through the PJM Interchange Energy Market at Day-ahead Prices and enable Transmission Customers to reserve transmission service with Transmission Congestion Charges and Transmission Loss Charges based on locational differences in Day-ahead Prices. Up-to Congestion Transactions submitted in the Day-ahead Energy Market shall not require transmission service and Transmission Customers shall not reserve transmission service for such Up-to Congestion Transactions. Market Participants whose purchases and sales, and Transmission Customers whose transmission uses are scheduled in the Day-ahead Energy Market, shall be obligated to purchase or sell energy, or pay Transmission Congestion Charges and Transmission Loss Charges, at the applicable Day-ahead Prices for the amounts scheduled.

(c) In the Real-time Energy Market, Market Participants that deviate from the amounts of energy purchases or sales, or Transmission Customers that deviate from the transmission uses, scheduled in the Day-ahead Energy Market shall be obligated to purchase or sell energy, or pay Transmission Congestion Charges and Transmission Loss Charges, for the amount of the deviations at the applicable Real-time Prices or price differences, unless otherwise specified by this Schedule.

(d) The following scheduling procedures and principles shall govern the commitment of resources to the Day-ahead Energy Market and the Real-time Energy Market over a period extending from one week to one hour prior to the real-time dispatch. Scheduling encompasses the day-ahead and hourly scheduling process, through which the Office of the Interconnection determines the Day-ahead Energy Market and determines, based on changing forecasts of conditions and actions by Market Participants and system constraints, a plan to serve the hourly energy and reserve requirements of the Internal Market Buyers and the purchase requests of the External Market Buyers in the least costly manner, subject to maintaining the reliability of the PJM Region. Scheduling does not encompass Coordinated External Transactions, which are subject to the procedures of Section 1.13 of this Schedule 1 of this Agreement. Scheduling shall be conducted as specified in Section 1.10.1A below, subject to the following condition. If the Office of the Interconnection's forecast for the next seven days projects a likelihood of Emergency conditions, the Office of the Interconnection may commit, for all or part of such seven day period, to the use of generation resources with notification or start-up times greater than one day as necessary in order to alleviate or mitigate such Emergency, in accordance with the Market Sellers' offers for such units for such periods and the specifications in the PJM

Manuals. Such resources committed by the Office of the Interconnection to alleviate or mitigate an Emergency will not receive Operating Reserve Credits nor otherwise be made whole for its hours of operation for the duration of any portion of such commitment that exceeds the maximum start-up and notification times for such resources during Hot Weather Alerts and Cold Weather Alerts, consistent with Sections 3.2.3 and 6.6 hereof.

1.10.1A Day-ahead Energy Market Scheduling.

The following actions shall occur not later than 10:30 a.m. on the day before the Operating Day for which transactions are being scheduled, or such other deadline as may be specified by the Office of the Interconnection in order to comply with the practical requirements and the economic and efficiency objectives of the scheduling process specified in this Schedule.

(a) Each Market Participant may submit to the Office of the Interconnection specifications of the amount and location of its customer loads and/or energy purchases to be included in the Day-ahead Energy Market for each hour of the next Operating Day, such specifications to comply with the requirements set forth in the PJM Manuals. Each Market Buyer shall inform the Office of the Interconnection of the prices, if any, at which it desires not to include its load in the Day-ahead Energy Market rather than pay the Day-ahead Price. PRD Providers that have committed Price Responsive Demand in accordance with the Reliability Assurance Agreement shall submit to the Office of the Interconnection, in accordance with procedures specified in the PJM Manuals, any desired updates to their previously submitted PRD Curves, provided that such updates are consistent with their Price Responsive Demand commitments, and provided further that PRD Providers that are not Load Serving Entities for the Price Responsive Demand at issue may only submit PRD Curves for the Real-time Energy Market. Price Responsive Demand that has been committed in accordance with the Reliability Assurance Agreement shall be presumed available for the next Operating Day in accordance with the most recently submitted PRD Curve unless the PRD Curve is updated to indicate otherwise. PRD Providers may also submit PRD Curves for any Price Responsive Demand that is not committed in accordance with the Reliability Assurance Agreement; provided that PRD Providers that are not Load Serving Entities for the Price Responsive Demand at issue may only submit PRD Curves for the Real-time Energy Market. All PRD Curves shall be on a PRD Substation basis, and shall specify the maximum time period required to implement load reductions.

(b) Each Generating Market Buyer shall submit to the Office of the Interconnection: (i) hourly schedules for resource increments, including hydropower units, self-scheduled by the Market Buyer to meet its Equivalent Load; and (ii) the Dispatch Rate at which each such self-scheduled resource will disconnect or reduce output, or confirmation of the Market Buyer's intent not to reduce output.

(c) All Market Participants shall submit to the Office of the Interconnection schedules for any energy exports, energy imports, and wheel through transactions involving use of generation or Transmission Facilities as specified below, and shall inform the Office of the Interconnection if the transaction is to be scheduled in the Day-ahead Energy Market. Any Market Participant that elects to schedule an export, import or wheel through transaction in the

Day-ahead Energy Market may specify the price (such price not to exceed the maximum price that may be specified in the PJM Manuals), if any, at which the export, import or wheel through transaction will be wholly or partially curtailed. The foregoing price specification shall apply to the applicable interface pricing point. Any Market Participant that elects not to schedule its export, import or wheel through transaction in the Day-ahead Energy Market shall inform the Office of the Interconnection if the parties to the transaction are not willing to incur Transmission Congestion and Loss Charges in the Real-time Energy Market in order to complete any such scheduled transaction. Scheduling of such transactions shall be conducted in accordance with the specifications in the PJM Manuals and the following requirements:

i) Market Participants shall submit schedules for all energy purchases for delivery within the PJM Region, whether from resources inside or outside the PJM Region;

ii) Market Participants shall submit schedules for exports for delivery outside the PJM Region from resources within the PJM Region that are not Dynamic Transfers to such entities pursuant to Section 1.12; and

iii) In addition to the foregoing schedules for exports, imports and wheel through transactions, Market Participants shall submit confirmations of each scheduled transaction from each other party to the transaction in addition to the party submitting the schedule, or the adjacent Control Area.

(c-1) A Market Participant may elect to submit in the Day-ahead Energy Market a form 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. The Office of Interconnection will schedule these transactions only to the extent this difference in Locational Marginal Prices is within the maximum amount specified by the Market Participant. A Virtual Transaction of this type is referred to as an "Up-to Congestion Transaction." Such Up-to Congestion Transactions may be wholly or partially scheduled depending on the price difference between the source and sink locations in the Day-ahead Energy Market. The maximum difference between the source and sink prices that a participant may specify shall be limited to +/- $50/MWh. The foregoing price specification shall apply to the price difference between the specified source and sink in the day-ahead scheduling process only. An accepted Up-to Congestion Transaction results in scheduled injection at a specified source and scheduled withdrawal of the same megawatt quantity at a specified sink in the Day-ahead Energy Market.

(c-2) ~~The source-sink paths on which an~~ Up-to Congestion Transactions may only be submitted ~~are limited~~ ~~limited~~at hubs, Residual Metered Load and interfaces not described in Tariff, Attachment K-Appendix, section 2.6A(b).~~to those paths posted on the PJM internet site and determined by the Office of the Interconnection using the following criteria:~~

~~Step 1: Start with the historic set of eligible nodes that were available as sources and sinks for interchange transactions on the PJM OASIS.~~

~~Step 2: Remove from the list of nodes described in Step 1 all load buses below 69 kV.~~

~~Step 3: Remove from the resulting set of nodes from Step 2 all generator buses at which no generators of 100 megawatts or more are connected.~~

~~Step 4: Remove from the results of Step 3 all electrically equivalent nodes.~~
Increment Offers and Decrement Bids may be only submitted at hubs, nodes at which physical generation or load is settled, Residual Metered Load and interfaces not described in Tariff, Attachment K-Appendix, section 2.6A(b).

(d) Market Sellers in the Day-ahead Energy Market shall submit offers for the supply of energy, demand reductions, or other services for the following Operating Day for each clock hour for which the Market Seller desires or is required to make its resource available to the Office of the Interconnection. Offers for the supply of energy may be cost-based, market-based, or both, and may vary hourly. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this Section 1.10.1A(d), Section 1.10.9B, Schedule 2 of the Operating Agreement, and the PJM Manuals, as applicable. Market Sellers owning or controlling the output of a Generation Capacity Resource that was committed in an FRR Capacity Plan, self-supplied, offered and cleared in a Base Residual Auction or Incremental Auction, or designated as replacement capacity, as specified in Attachment DD of the PJM Tariff, and that has not been rendered unavailable by a Generator Planned Outage, a Generator Maintenance Outage, or a Generator Forced Outage shall submit offers for the available capacity of such Generation Capacity Resource, including any portion that is self-scheduled by the Generating Market Buyer. Such offers shall be based on the ICAP equivalent of the Market Seller's cleared UCAP capacity commitment, provided, however, where the underlying resource is a Capacity Storage Resource or an Intermittent Resource, the Market Seller shall satisfy the must offer requirement by either self-scheduling or offering the unit as a dispatchable resource, in accordance with the PJM Manuals, where the hourly day-ahead self-scheduled values for such Capacity Storage Resources and Intermittent Resources may vary hour to hour from the capacity commitment. Any offer not designated as a Maximum Emergency offer shall be considered available for scheduling and dispatch under both Emergency and non-Emergency conditions. Offers may only be designated as Maximum Emergency offers to the extent that the Generation Capacity Resource falls into at least one of the following categories:

i) Environmental limits. If the resource has a limit on its run hours imposed by a federal, state, or other governmental agency that will significantly limit its availability, on either a temporary or long-term basis. This includes a resource that is limited to operating only during declared PJM capacity emergencies by a governmental authority.

ii) Fuel limits. If physical events beyond the control of the resource owner result in the temporary interruption of fuel supply and there is limited on-site fuel storage. A fuel supplier's exercise of a contractual right to interrupt supply or delivery under an interruptible service agreement shall not qualify as an event beyond the control of the resource owner.

iii) Temporary emergency conditions at the unit. If temporary emergency physical conditions at the resource significantly limit its availability.

iv) Temporary megawatt additions. If a resource can provide additional megawatts on a temporary basis by oil topping, boiler over-pressure, or similar techniques, and such megawatts are not ordinarily otherwise available.

The submission of offers for resource increments that have not cleared in a Base Residual Auction or an Incremental Auction, were not committed in an FRR Capacity Plan, and were not designated as replacement capacity under Attachment DD of the PJM Tariff shall be optional, but any such offers must contain the information specified in the Office of the Interconnection's Offer Data specification, Operating Agreement Schedule 1, sections 1.10.1A(d) and 1.10.9B, Operating Agreement, Schedule 2 , and the PJM Manuals, as applicable. Energy offered from generation resources that have not cleared a Base Residual Auction or an Incremental Auction, were not committed in an FRR Capacity Plan, and were not designated as replacement capacity under Attachment DD of the PJM Tariff shall not be supplied from resources that are included in or otherwise committed to supply the Operating Reserves of a Control Area outside the PJM Region.

The foregoing offers:

i) Shall specify the Generation Capacity Resource or Demand Resource and energy or demand reduction amount, respectively, for each clock hour in the offer period;

ii) Shall specify the amounts and prices for each clock hour during the entire Operating Day for each resource component offered by the Market Seller to the Office of the Interconnection;

iii) May specify for generation resources offer parameters for each clock hour during the entire Operating Day, as applicable and in accordance with section 1.10.9B below, including: (1) Minimum Run Time; (2) maximum run time; (3) Start-up Costs; (4) No-load Costs; (5) Incremental Energy Offer; (6) notification time; (7) availability; (8) ramp rate; (9) Economic Minimum; (10) Economic Maximum; (11) emergency minimum MW; and (12) emergency maximum MW, and specify offer parameters for Demand Resources for each clock hour during the entire Operating Day, as applicable and in accordance with section 1.10.9B below, including: (1) minimum down time; (2) shutdown costs; (3) Incremental Energy Offer; (4) notification time; (5) Economic Minimum; and (6) Economic Maximum.;

iv) Shall set forth any special conditions upon which the Market Seller proposes to supply a resource increment, including any curtailment rate specified in a bilateral contract for the output of the resource, or any cancellation fees;

v) May include a schedule of offers for prices and operating data contingent on acceptance by the deadline specified in this Schedule, with additional schedules applicable if accepted after the foregoing deadline;

vi) Shall constitute an offer to submit the resource increment to the Office of the Interconnection for scheduling and dispatch in accordance with the terms of the offer for the clock hour, which offer shall remain open through the Operating Day, for which the offer is submitted, unless the Market Seller a) submits a Real-time Offer for the applicable clock hour, or b) updates the availability of its offer for that hour, as further described in the PJM Manuals;

vii) Shall be final as to the price or prices at which the Market Seller proposes to supply energy or other services to the PJM Interchange Energy Market, such price or prices being guaranteed by the Market Seller for the period extending through the end of the following Operating Day, unless modified after the close of the Day-ahead Energy Market as permitted pursuant to sections 1.10.9A or 1.10.9B below;

viii) Shall not exceed an energy offer price of $1,000/megawatt-hour for all generation resources, except (1) when a Market Seller's cost-based offer is above $1,000/megawatt-hour and less than or equal to $2,000/megawatt-hour, then its market-based offer must be less than or equal to the cost-based offer; and (2) when a Market Seller's cost-based offer is greater than $2,000/megawatt-hour, then its market-based offer must be less than or equal to $2,000/megawatt-hour; and

ix) Shall not exceed a *demand reduction* offer price of $1,000/megawatt-hour, *except when an Economic Load Response Participant, an Emergency Load Response participant, or a Pre-Emergency Load Response participant submits a cost-based offer that includes an incremental cost component that is above $1,000/megawatt-hour, then its market-based offer must be less than or equal to the cost-based offer but in no event greater than $2,000/megawatt-hour; and*

x) Shall not exceed an energy offer price of $0.00/MWh for pumped storage hydropower units scheduled by the Office of the Interconnection pursuant to the hydro optimization tool in the Day-ahead Energy Market.

(e) A Market Seller that wishes to make a resource available to sell Regulation service shall submit an offer for Regulation for each clock hour for which the Market Seller desires to make its resource available to the Office of the Interconnection to provide Regulation that shall specify the megawatts of Regulation being offered, which must equal or exceed 0.1 megawatts, the Regulation Zone for which such Regulation is offered, the price of the capability offer in dollars per MW, the price of the performance offer in Dollars per change in MW, and such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer and the resource's opportunity costs. Such offers may vary hourly, and may be updated each hour, up to 65 minutes before the applicable clock hour during the Operating Day. The total of the performance offer multiplied by the historical average mileage used in the market clearing plus the capability offer shall not exceed $100/megawatt-hour in the case of

Regulation offered for all Regulation Zones. In addition to any market-based offer for Regulation, the Market Seller also shall submit a cost-based offer. A cost-based offer must be in the form specified in the PJM Manuals and consist of the following components as well as any other components specified in the PJM Manuals:

i. The costs (in $/MW) of the fuel cost increase due to the steady-state heat rate increase resulting from operating the unit at lower megawatt output incurred from the provision of Regulation shall apply to the capability offer;

ii. The cost increase (in $/ΔMW) in costs associated with movement of the regulation resource incurred from the provision of Regulation shall apply to the performance offer; and

iii. An adder of up to $12.00 per megawatt of Regulation provided applied to the capability offer.

Qualified Regulation capability must satisfy the measurement and verification tests specified in the PJM Manuals.

(f) Each Market Seller owning or controlling the output of a Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative shall submit a forecast of the availability of each such Generation Capacity Resource for the next seven days. A Market Seller (i) may submit a non-binding forecast of the price at which it expects to offer a generation resource increment to the Office of the Interconnection over the next seven days, and (ii) shall submit a binding offer for energy, along with Start-up Costs and No-load Costs, if any, for the next seven days or part thereof, for any generation resource with minimum notification or start-up requirement greater than 24 hours. Such resources committed by the Office of the Interconnection will not receive Operating Reserve Credits nor otherwise be made whole for its hours of operation for the duration of any portion of such commitment that exceeds the maximum start-up and notification times for such resources during Hot Weather Alerts and Cold Weather Alerts, consistent with Sections 3.2.3 and 6.6 hereof.

(g) Each component of an offer by a Market Seller of a Generation Capacity Resource that is constant for the entire Operating Day and does not vary hour to hour shall remain in effect for subsequent Operating Days until superseded or canceled.

(h) The Office of the Interconnection shall post the total hourly loads scheduled in the Day-ahead Energy Market, as well as, its estimate of the combined hourly load of the Market Buyers for the next four days, and peak load forecasts for an additional three days.

(i) Except for Economic Load Response Participants, all Market Participants may submit Virtual Transactions that apply to the Day-ahead Energy Market only. Such Virtual Transactions must comply with the requirements set forth in the PJM Manuals and must specify amount, location and price, if any, at which the Market Participant desires to purchase or sell energy in the Day-ahead Energy Market. The Office of the Interconnection may require that a

market participant shall not submit in excess of a defined number of bid/offer segments in the Day-ahead Energy Market, as specified in the PJM Manuals, when the Office of the Interconnection determines that such limit is required to avoid or mitigate significant system performance problems related to bid/offer volume. Notice of the need to impose such limit shall be provided prior to 10:00 a.m. EPT on the day that the Day-ahead Energy Market will clear. For purposes of this provision, a bid/offer segment is each pairing of price and megawatt quantity submitted as part of an Increment Offer or Decrement Bid. For purposes of applying this provision to an Up-to Congestion Transaction, a bid/offer segment shall refer to the pairing of a source and sink designation, as well as price and megawatt quantity, that comprise each Up-to Congestion Transaction.

(j) A Market Seller that wishes to make a generation resource or Demand Resource available to sell Synchronized Reserve shall submit an offer for Synchronized Reserve for each clock hour for which the Market Seller desires or is required to make its resource available to the Office of the Interconnection to provide Synchronized Reserve that shall specify the megawatts of Synchronized Reserve being offered, which must equal or exceed 0.1 megawatts, the price of the offer in dollars per megawatt hour, and such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer and the energy used by the generation resource to provide the Synchronized Reserve and the generation resource's unit specific opportunity costs. Such offers may vary hourly, and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day. The price of the offer shall not exceed the variable operating and maintenance costs for providing Synchronized Reserve plus seven dollars and fifty cents.

(k) An Economic Load Response Participant that wishes to participate in the Day-ahead Energy Market by reducing demand shall submit an offer to reduce demand to the Office of the Interconnection for each clock hour for which the Economic Load Response Participant desires to make its resource available to the Office of the Interconnection to reduce demand. The offer must equal or exceed 0.1 megawatts, may vary hourly, and shall specify: (i) the amount of the offered curtailment in minimum increments of .1 megawatts: (ii) the Day-ahead Locational Marginal Price above which the end-use customer will reduce load, subject to section 1.10.1A(d)(ix); and (iii) at the Economic Load Response Participant's option, start-up costs associated with reducing load, including direct labor and equipment costs, opportunity costs, and/or a minimum of number of contiguous hours for which the load reduction must be committed. Such offers may be updated each hour, up to 65 minutes before the applicable clock hour during the Operating Day. Economic Load Response Participants submitting offers to reduce demand in the Day-ahead Energy Market may establish an incremental offer curve, provided that such offer curve shall be limited to ten price pairs (in MWs) per hour.

(l) Market Sellers owning or controlling the output of a Demand Resource that was committed in an FRR Capacity Plan, or that was self-supplied or that offered and cleared in a Base Residual Auction or Incremental Auction, may submit demand reduction bids for the available load reduction capability of the Demand Resource. The submission of demand reduction bids for Demand Resource increments that were not committed in an FRR Capacity Plan, or that have not cleared in a Base Residual Auction or Incremental Auction, shall be optional, but any such bids must contain the information required to be included in such bids, as

specified in the PJM Economic Load Response Program. A Demand Resource that was committed in an FRR Capacity Plan, or that was self-supplied or offered and cleared in a Base Residual Auction or Incremental Auction, may submit a demand reduction bid in the Day-ahead Energy Market as specified in the Economic Load Response Program; provided, however, that in the event of an Emergency PJM shall require Demand Resources to reduce load, notwithstanding that the Zonal LMP at the time such Emergency is declared is below the price identified in the demand reduction bid.

(m) Market Sellers providing Day-ahead Scheduling Reserves Resources shall submit in the Day-ahead Scheduling Reserves Market: 1) a price offer in dollars per megawatt hour; and 2) such other information specified by the Office of the Interconnection as may be necessary to determine any relevant opportunity costs for the resource(s). The foregoing notwithstanding, to qualify to submit Day-ahead Scheduling Reserves pursuant to this section, the Day-ahead Scheduling Reserves Resources shall submit energy offers in the Day-ahead Energy Market including start-up and shut-down costs for generation resource and Demand Resources, respectively, and all generation resources that are capable of providing Day-ahead Scheduling Reserves that a particular resource can provide that service. The megawatt quantity of Day-ahead Scheduling Reserves that a particular resource can provide in a given hour will be determined based on the energy Offer Data submitted in the Day-ahead Energy Market, as detailed in the PJM Manuals.

1.10.1B Demand Bid Scheduling and Screening

(a) The Office of the Interconnection shall apply Demand Bid Screening to all Demand Bids submitted in the Day-ahead Energy Market for each Load Serving Entity, separately by Zone. Using Demand Bid Screening, the Office of the Interconnection will automatically reject a Load Serving Entity's Demand Bids in any future Operating Day for which the Load Serving Entity submits bids if the total megawatt volume of such bids would exceed the Load Serving Entity's Demand Bid Limit for any hour in such Operating Day, unless the Office of the Interconnection permits an exception pursuant to subsection (d) below.

(b) On a daily basis, PJM will update and post each Load Serving Entity's Demand Bid Limit in each applicable Zone. Such Demand Bid Limit will apply to all Demand Bids submitted by that Load Serving Entity for each future Operating Day for which it submits bids. The Demand Bid Limit is calculated using the following equation:

Demand Bid Limit = greater of (Zonal Peak Demand Reference Point * 1.3), or (Zonal Peak Demand Reference Point + 10MW)

Where:

1. Zonal Peak Demand Reference Point = for each Zone: the product of (a) LSE Recent Load Share, multiplied by (b) Peak Daily Load Forecast.
2. LSE Recent Load Share is the Load Serving Entity's highest share of Network Load in each Zone for any hour over the most recently available seven Operating Days for which PJM has data.

3. Peak Daily Load Forecast is PJM's highest available peak load forecast for each applicable Zone that is calculated on a daily basis.

(c) A Load Serving Entity whose Demand Bids are rejected as a result of Demand Bid Screening may change its Demand Bids to reduce its total megawatt volume to a level that does not exceed its Demand Bid Limit, and may resubmit them subject to the applicable rules related to bid submission outlined in Tariff, Operating Agreement and PJM Manuals.

(d) PJM may allow a Load Serving Entity to submit bids in excess of its Demand Bid Limit when circumstances exist that will cause, or are reasonably expected to cause, a Load Serving Entity's actual load to exceed its Demand Bid Limit on a given Operating Day. Examples of such circumstances include, but are not limited to, changes in load commitments due to state sponsored auctions, mergers and acquisitions between PJM Members, and sales and divestitures between PJM Members. A Load Serving Entity may submit a written exception request to the Office of Interconnection for a higher Demand Bid Limit for an affected Operating Day. Such request must include a detailed explanation of the circumstances at issue and supporting documentation that justify the Load Serving Entity's expectation that its actual load will exceed its Demand Bid Limit.

1.10.2 Pool-scheduled Resources.

Pool-scheduled resources are those resources for which Market Participants submitted offers to sell energy in the Day-ahead Energy Market and offers to reduce demand in the Day-ahead Energy Market, which the Office of the Interconnection scheduled in the Day-ahead Energy Market as well as generators committed by the Office of the Interconnection subsequent to the Day-ahead Energy Market. Such resources shall be committed to provide energy in the real-time dispatch unless the schedules for such units are revised pursuant to Sections 1.10.9 or 1.11. Pool-scheduled resources shall be governed by the following principles and procedures.

(a) Pool-scheduled resources shall be selected by the Office of the Interconnection on the basis of the prices offered for energy and demand reductions and related services, whether the resource is expected to be needed to maintain system reliability during the Operating Day, Start-up Costs, No-load Costs and cancellation fees, and the specified operating characteristics, offered by Market Sellers to the Office of the Interconnection by the offer deadline specified in Section 1.10.1A. Hydropower units can only be pool-scheduled if they are pumped storage units and scheduled by the Office of the Interconnection pursuant to the hydro optimization tool in the Day-ahead Energy Market.

(b) A resource that is scheduled by a Market Participant to support a bilateral sale, or that is self-scheduled by a Generating Market Buyer, shall not be selected by the Office of the Interconnection as a pool-scheduled resource except in an Emergency.

(c) Market Sellers offering energy from hydropower or other facilities with fuel or environmental limitations may submit data to the Office of the Interconnection that is sufficient

to enable the Office of the Interconnection to determine the available operating hours of such facilities.

(d) The Market Seller of a resource selected as a pool-scheduled resource shall receive payments or credits for energy, demand reductions or related services, or for Start-up Costs and No-load Costs, from the Office of the Interconnection on behalf of the Market Buyers in accordance with Section 3 of this Schedule 1. Alternatively, the Market Seller shall receive, in lieu of Start-up Costs and No-load Costs, its actual costs incurred, if any, up to a cap of the resource's Start-up Costs, if the Office of the Interconnection cancels its selection of the resource as a pool-scheduled resource and so notifies the Market Seller before the resource is synchronized.

(e) Market Participants shall make available their pool-scheduled resources to the Office of the Interconnection for coordinated operation to supply the Operating Reserves needs of the applicable Control Zone.

(f) Economic Load Response Participants offering to reduce demand shall specify: (i) the amount of the offered curtailment, which offer must equal or exceed 0.1 megawatts, in minimum increments of .1 megawatts; (ii) the real-time Locational Marginal Price above which the end-use customer will reduce load; and (iii) at the Economic Load Response Participant's option, shut-down costs associated with reducing load, including direct labor and equipment costs, opportunity costs, and/or a minimum number of contiguous hours for which the load reduction must be committed. Economic Load Response Participants submitting offers to reduce demand in the Real-time Energy Market may establish an incremental offer curve, provided that such offer curve shall be limited to ten price pairs (in MWs). Economic Load Response Participants offering to reduce demand shall also indicate the hours that the demand reduction is not available.

1.10.3 Self-scheduled Resources.

Self-scheduled resources shall be governed by the following principles and procedures.

(a) Each Generating Market Buyer shall use all reasonable efforts, consistent with Good Utility Practice, not to self-schedule resources in excess of its Equivalent Load.

(b) The offered prices of resources that are self-scheduled, or otherwise not following the dispatch orders of the Office of the Interconnection, shall not be considered by the Office of the Interconnection in determining Locational Marginal Prices.

(c) Market Participants shall make available their self-scheduled resources to the Office of the Interconnection for coordinated operation to supply the Operating Reserves needs of the applicable Control Zone, by submitting an offer as to such resources.

(d) A Market Participant self-scheduling a resource in the Day-ahead Energy Market that does not deliver the energy in the Real-time Energy Market, shall replace the energy not

delivered with energy from the Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

(e) Hydropower units, excluding pumped storage units, may only be self-scheduled.

1.10.4 Capacity Resources.

(a) A Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative that is selected as a pool-scheduled resource shall be made available for scheduling and dispatch at the direction of the Office of the Interconnection. Such a Generation Capacity Resource that does not deliver energy as scheduled shall be deemed to have experienced a Generator Forced Outage to the extent of such energy not delivered. A Market Participant offering such Generation Capacity Resource in the Day-ahead Energy Market shall replace the energy not delivered with energy from the Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

(b) Energy from a Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative that has not been scheduled in the Day-ahead Energy Market may be sold on a bilateral basis by the Market Seller, may be self-scheduled, or may be offered for dispatch during the Operating Day in accordance with the procedures specified in this Schedule. Such a Generation Capacity Resource that has not been scheduled in the Day-ahead Energy Market and that has been sold on a bilateral basis must be made available upon request to the Office of the Interconnection for scheduling and dispatch during the Operating Day if the Office of the Interconnection declares a Maximum Generation Emergency. Any such resource so scheduled and dispatched shall receive the applicable Real-time Price for energy delivered.

(c) A resource that has been self-scheduled shall not receive payments or credits for Start-up Costs or No-load Costs.

1.10.5 External Resources.

(a) External Resources may submit offers to the PJM Interchange Energy Market, in accordance with the day-ahead and real-time scheduling processes specified above. An External Resource selected as a pool-scheduled resource shall be made available for scheduling and dispatch at the direction of the Office of the Interconnection, and except as specified below shall be compensated on the same basis as other pool-scheduled resources. External Resources that are not capable of Dynamic Transfer shall, if selected by the Office of the Interconnection on the basis of the Market Seller's Offer Data, be block loaded on an hourly scheduled basis. Market Sellers shall offer External Resources to the PJM Interchange Energy Market on either a resource-specific or an aggregated resource basis. A Market Participant whose pool-scheduled resource does not deliver the energy scheduled in the Day-ahead Energy Market shall replace such energy not delivered as scheduled in the Day-ahead Energy Market with energy from the PJM Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

(b) Offers for External Resources from an aggregation of two or more generating units shall so indicate, and shall specify, in accordance with the Offer Data requirements specified by the Office of the Interconnection: (i) energy prices; (ii) hours of energy availability; (iii) a minimum dispatch level; (iv) a maximum dispatch level; and (v) unless such information has previously been made available to the Office of the Interconnection, sufficient information, as specified in the PJM Manuals, to enable the Office of the Interconnection to model the flow into the PJM Region of any energy from the External Resources scheduled in accordance with the Offer Data.

(c) Offers for External Resources on a resource-specific basis shall specify the resource being offered, along with the information specified in the Offer Data as applicable.

1.10.6 External Market Buyers.

(a) Deliveries to an External Market Buyer not subject to Dynamic Transfer by the Office of the Interconnection shall be delivered on a block loaded basis to the bus or buses at the electrical boundaries of the PJM Region, or in such area with respect to an External Market Buyer's load within such area not served by Network Service, at which the energy is delivered to or for the External Market Buyer. External Market Buyers shall be charged (which charge may be positive or negative) at either the Day-ahead Prices or Real-time Prices, whichever is applicable, for energy at the foregoing bus or buses.

(b) An External Market Buyer's hourly schedules for energy purchased from the PJM Interchange Energy Market shall conform to the ramping and other applicable requirements of the interconnection agreement between the PJM Region and the Control Area to which, whether as an intermediate or final point of delivery, the purchased energy will initially be delivered.

(c) The Office of the Interconnection shall curtail deliveries to an External Market Buyer if necessary to maintain appropriate reserve levels for a Control Zone as defined in the PJM Manuals, or to avoid shedding load in such Control Zone.

1.10.6A Transmission Loading Relief Customers.

(a) An entity that desires to elect to pay Transmission Congestion Charges in order to continue its energy schedules during an Operating Day over contract paths outside the PJM Region in the event that PJM initiates Transmission Loading Relief that otherwise would cause PJM to request security coordinators to curtail such Member's energy schedules shall:

(i) enter its election on OASIS by 10:30 a.m. of the day before the Operating Day, in accordance with procedures established by PJM, which election shall be applicable for the entire Operating Day; and

(ii) if PJM initiates Transmission Loading Relief, provide to PJM, at such time and in accordance with procedures established by PJM, the hourly integrated energy schedules that impacted the PJM Region (as indicated from the NERC Interchange Distribution Calculator) during the Transmission Loading Relief.

(b) If an entity has made the election specified in Section (a), then PJM shall not request security coordinators to curtail such entity's energy transactions, except as may be necessary to respond to Emergencies.

(c) In order to make elections under this Section 1.10.6A, an entity must (i) have met the creditworthiness standards established by the Office of the Interconnection or provided a letter of credit or other form of security acceptable to the Office of the Interconnection, and (ii) have executed either the Agreement, a Service Agreement under the PJM Tariff, or other agreement committing to pay all Transmission Congestion Charges incurred under this Section.

1.10.7 Bilateral Transactions.

Bilateral transactions as to which the parties have notified the Office of the Interconnection by the deadline specified in Section 1.10.1A that they elect not to be included in the Day-ahead Energy Market and that they are not willing to incur Transmission Congestion Charges in the Real-time Energy Market shall be curtailed by the Office of the Interconnection as necessary to reduce or alleviate transmission congestion. Bilateral transactions that were not included in the Day-ahead Energy Market and that are willing to incur congestion charges and bilateral transactions that were accepted in the Day-ahead Energy Market shall continue to be implemented during periods of congestion, except as may be necessary to respond to Emergencies.

1.10.8 Office of the Interconnection Responsibilities.

(a) The Office of the Interconnection shall use its best efforts to determine (i) the least-cost means of satisfying the projected hourly requirements for energy, Operating Reserves, and other ancillary services of the Market Buyers, including the reliability requirements of the PJM Region, of the Day-ahead Energy Market, and (ii) the least-cost means of satisfying the Operating Reserve and other ancillary service requirements for any portion of the load forecast of the Office of the Interconnection for the Operating Day in excess of that scheduled in the Day-ahead Energy Market. In making these determinations, the Office of the Interconnection shall take into account: (i) the Office of the Interconnection's forecasts of PJM Interchange Energy Market and PJM Region energy requirements, giving due consideration to the energy requirement forecasts and purchase requests submitted by Market Buyers and PRD Curves properly submitted by Load Serving Entities for the Price Responsive Demand loads they serve; (ii) the offers submitted by Market Sellers; (iii) the availability of limited energy resources; (iv) the capacity, location, and other relevant characteristics of self-scheduled resources; (v) the objectives of each Control Zone for Operating Reserves, as specified in the PJM Manuals; (vi) the requirements of each Regulation Zone for Regulation and other ancillary services, as specified in the PJM Manuals; (vii) the benefits of avoiding or minimizing transmission constraint control operations, as specified in the PJM Manuals; and (viii) such other factors as the Office of the Interconnection reasonably concludes are relevant to the foregoing determination, including, without limitation, transmission constraints on external coordinated flowgates to the extent provided by section 1.7.6. The Office of the Interconnection shall develop a Day-ahead Energy Market based on the foregoing determination, and shall determine

the Day-ahead Prices resulting from such schedule. The Office of the Interconnection shall report the planned schedule for a hydropower resource to the operator of that resource as necessary for plant safety and security, and legal limitations on pond elevations.

(b) By 1:30 p.m., or as soon as practicable thereafter, of the day before each Operating Day, or such other deadline as may be specified by the Office of the Interconnection in the PJM Manuals, the Office of the Interconnection shall: (i) post the aggregate Day-ahead Energy Market results; (ii) post the Day-ahead Prices; and (iii) inform the Market Sellers, Market Buyers, and Economic Load Response Participants of their scheduled injections, withdrawals, and demand reductions respectively. The foregoing notwithstanding, the deadlines set forth in this subsection shall not apply if the Office of the Interconnection is unable to obtain Market Participant bid/offer data due to extraordinary circumstances. For purposes of this subsection, extraordinary circumstances shall mean a technical malfunction that limits, prohibits or otherwise interferes with the ability of the Office of the Interconnection to obtain Market Participant bid/offer data prior to 11:59 p.m. on the day before the affected Operating Day. Extraordinary circumstances do not include a Market Participant's inability to submit bid/offer data to the Office of the Interconnection. If the Office of the Interconnection is unable to clear the Day-ahead Energy Market prior to 11:59 p.m. on the day before the affected Operating Day as a result of such extraordinary circumstances, the Office of the Interconnection shall notify Members as soon as practicable.

(c) Following posting of the information specified in Section 1.10.8(b), and absent extraordinary circumstances preventing the clearing of the Day-ahead Energy Market, the Office of the Interconnection shall revise its schedule of generation resources to reflect updated projections of load, conditions affecting electric system operations in the PJM Region, the availability of and constraints on limited energy and other resources, transmission constraints, and other relevant factors.

(d) Market Buyers shall pay PJMSettlement and Market Sellers shall be paid by PJMSettlement for the quantities of energy scheduled in the Day-ahead Energy Market at the Day-ahead Prices when the Day-ahead Price is positive. Market Buyers shall be paid by PJMSettlement and Market Sellers shall pay PJMSettlement for the quantities of energy scheduled in the Day-ahead Energy Market at the Day-ahead Prices when the Day-ahead Price is negative. Economic Load Response Participants shall be paid for scheduled demand reductions pursuant to Section 3.3A of this Schedule. Notwithstanding the foregoing, if the Office of the Interconnection is unable to clear the Day-ahead Energy Market prior to 11:59 p.m. on the day before the affected Operating Day due to extraordinary circumstances as described in subsection (b) above, no settlements shall be made for the Day-ahead Energy Market, no scheduled megawatt quantities shall be established, and no Day-ahead Prices shall be established for that Operating Day. Rather, for purposes of settlements for such Operating Day, the Office of the Interconnection shall utilize a scheduled megawatt quantity and price of zero and all settlements, including Financial Transmission Right Target Allocations, will be based on the real-time quantities and prices as determined pursuant to Sections 2.4 and 2.5 hereof.

(e) If the Office of the Interconnection discovers an error in prices and/or cleared quantities in the Day-ahead Energy Market, Real-time Energy Market, Ancillary Services

Markets or Day Ahead Scheduling Reserve Market after it has posted the results for these markets on its Web site, the Office of the Interconnection shall notify Market Participants of the error as soon as possible after it is found, but in no event later than 12:00 p.m. of the second Business Day following the Operating Day for the Ancillary Services Markets and Real-time Energy Market, and no later than 5:00 p.m. of the second Business Day following the initial publication of the results for the Day-ahead Scheduling Reserve Market and Day-ahead Energy Market.

After this initial notification, if the Office of the Interconnection determines it is necessary to post modified results, it shall provide notification of its intent to do so, together with all available supporting documentation, by no later than 5:00 p.m. of the fifth Business Day following the Operating Day for the Ancillary Services Markets and Real-time Energy Market, and no later than 5:00 p.m. of the fifth Business Day following the initial publication of the results in the Day-ahead Scheduling Reserve Market and the Day-ahead Energy Market. Thereafter, the Office of the Interconnection must post on its Web site the corrected results by no later than 5:00 p.m. of the tenth calendar day following the Operating Day for the Ancillary Services Markets, Day-ahead Energy Market and Real-time Energy Market, and no later than 5:00 p.m. of the tenth calendar day following the initial publication of the results in the Day-ahead Scheduling Reserve Market. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced market results are under publicly noticed review by the FERC.

(f) Consistent with Section 18.17.1 of the PJM Operating Agreement, and notwithstanding anything to the contrary in the Operating Agreement or in the PJM Tariff, to allow the tracking of Market Participants' non-aggregated bids and offers over time as required by FERC Order No. 719, the Office of the Interconnection shall post on its Web site the non-aggregated bid data and Offer Data submitted by Market Participants (for participation in the PJM Interchange Energy Market) approximately four months after the bid or offer was submitted to the Office of the Interconnection.

1.10.9 Hourly Scheduling.

(a) Following the initial posting by the Office of the Interconnection of the Locational Marginal Prices resulting from the Day-ahead Energy Market, and subject to the right of the Office of the Interconnection to schedule and dispatch pool-scheduled resources and to direct that schedules be changed in an Emergency, and absent extraordinary circumstances preventing the clearing of the Day-ahead Energy Market, a generation rebidding period shall exist. Typically the rebidding period shall be from the time the Office of the Interconnection posts the results of the Day-ahead Energy Market until 2:15 p.m. on the day before each Operating Day. However, should the clearing of the Day-ahead Energy Market be significantly delayed, the Office of the Interconnection may establish a revised rebidding period. During the rebidding period, Market Participants may submit revisions to generation Offer Data for the next Operating Day. Adjustments to the Day-ahead Energy Market shall be settled at the applicable Real-time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-ahead Energy Market at the applicable Day-ahead Prices.

(b) A Market Participant may adjust the schedule of a resource under its dispatch control on an hour-to-hour basis beginning at 10:00 p.m. of the day before each Operating Day, provided that the Office of the Interconnection is notified not later than 65 minutes prior to the hour in which the adjustment is to take effect, as follows and as specified in section 1.10.9A of this Schedule:

i) A Generating Market Buyer may self-schedule any of its resource increments, including hydropower resources, not previously designated as self-scheduled and not selected as a pool-scheduled resource in the Day-ahead Energy Market;

ii) A Market Participant may request the scheduling of a non-firm bilateral transaction; or

iii) A Market Participant may request the scheduling of deliveries or receipts of Spot Market Energy; or

iv) A Generating Market Buyer may remove from service a resource increment, including a hydropower resource, that it had previously designated as self-scheduled, provided that the Office of the Interconnection shall have the option to schedule energy from any such resource increment that is a Capacity Resource at the price offered in the scheduling process, with no obligation to pay any Start-Up Costs.

(c) An External Market Buyer may refuse delivery of some or all of the energy it requested to purchase in the Day-ahead Energy Market by notifying the Office of the Interconnection of the adjustment in deliveries not later than 65 minutes prior to the hour in which the adjustment is to take effect, but any such adjustment shall not affect the obligation of the External Market Buyer to pay for energy scheduled on its behalf in the Day-ahead Energy Market at the applicable Day-ahead Prices.

(d) The Office of the Interconnection shall provide External Market Buyers and External Market Sellers and parties to bilateral transactions with any revisions to their schedules resulting from the rebidding period by 6:30 p.m. on the day before each Operating Day. The Office of the Interconnection may also commit additional resources after such time as system conditions require. For each hour in the Operating Day, as soon as practicable after the deadlines specified in the foregoing subsection of this Section 1.10, the Office of the Interconnection shall provide External Market Buyers and External Market Sellers and parties to bilateral transactions with any revisions to their schedules for the hour.

1.10.9A Updating Offers in Real-time

(a) Each Market Seller may submit Real-time Offers for a resource up to 65 minutes before the applicable clock hour, and such Real-time Offers shall supersede any previous offer for that

resource for the clock hour, as further described in the PJM Manuals and subject to the following conditions:

(*i*) A market-based Real-time Offer shall not exceed the applicable energy offer caps specified in this Schedule. Once a Market Seller's resource is committed for an applicable clock hour, the Market Seller may not increase its Incremental Energy Offer and may only submit a market-based Real-time Offer that is higher than its market-based offer that was in effect at the time of commitment to reflect increases in the resource's cost-based Start-up Costs and cost-based No-load Costs. The Market Seller may elect not to have its market-based offer considered for dispatch and to have only its lowest cost-based offer considered for the remainder of the Operating Day.

(*ii*) Cost-based Real-time Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection's Offer Data specification, Operating Agreement, Schedule 1, sections 1.10.1A(d) and 1.10.9B, Operating Agreement, Schedule 2 and the PJM Manuals, as applicable. If a Market Seller submits a market-based Real-time Offer for a particular clock hour in accordance with subsection (c) below, or if updates to a cost-based offer are required by the Market Seller's approved Fuel Cost Policy, the Market Seller shall update its previously submitted cost-based Real-time Offer.

(*iii*) If a Market Seller's available cost-based offer is not compliant with Operating Agreement, Schedule 2 and the PJM Manuals at the time a Market Seller submits a market-based Real-time Offer for an applicable clock hour during the Operating Day, the Market Seller must submit an updated cost-based Real-time Offer consisting of an Incremental Energy Offer, Start-up Cost and No-load Cost for that clock hour that is compliant with Operating Agreement, Schedule 2 and the PJM Manuals.

(b) Each Market Seller may submit Real-time Offers for a resource during and through the end of the applicable clock hour to update only the following offer parameters, as further described in the PJM Manuals: (1) Economic Minimum; (2) Economic Maximum; (3) emergency minimum MW; (4) emergency maximum MW; (5) unit availability status; and (6) fixed output indicator. Such Real-time Offers shall supersede any previous offer for that resource for the clock hour.

1.10.9B Offer Parameter Flexibility

(a) Market Sellers may, in accordance with sections 1.10.1A and 1.10.9A above, this section 1.10.9B, and the PJM Manuals, update offer parameters at any time up to 65 minutes before the applicable clock hour, including prior to the close of the Day-ahead Energy Market and prior to the close of the rebidding period specified in section 1.10.9, except that Market Sellers may not update their offers for the supply of energy or demand reduction: (1) during the period after the close the Day-ahead Energy Market and prior to the posting of the Day-ahead Energy Market results pursuant to section 1.10.8(b); or (2) during the period after close of the rebidding period and prior to PJM announcing the results of the rebidding period pursuant to section 1.10.9(d).

(b) For generation resource offers, Market Sellers may vary for each clock hour during the entire Operating Day the following offer parameters: (1) cost-based Start-up Costs; (2) cost-based No-load Costs; (3) Incremental Energy Offer; (4) Economic Minimum and Economic Maximum; (5) emergency minimum MW and emergency maximum MW; and (6) for Real-time Offers only, *(i)* notification time and *(ii) for uncommitted hours only*, Minimum Run Time.

(c) For Demand Resource offers, Market Sellers may vary for each clock hour during the entire Operating Day the following offer parameters: (1) shutdown costs, (2) Incremental Energy Offer; (3) Economic Minimum; (4) Economic Maximum; and (5) for Real-time Offers only, *(i)* notification time and *(ii) for uncommitted hours only*, minimum down time.

(d) After the announcement of the results of the rebidding period pursuant to section 1.10.9(d), *a* Market Seller may submit a Real-time Offer where offer parameters *may differ from the offer originally submitted in the Day-ahead Energy Market, except that a Market Seller may not submit a Real-time Offer that changes, of the offer parameters listed in section 1.10.1A(d), the* MW amounts specified in the Incremental Energy Offer, *ramp rate, maximum run time*, and availability*; provided, however, Market Sellers of dual-fueled resources may submit Real-time Offers for such resources that change the availability of a submitted cost-based offer.*

Section(s) of the
PJM Operating Agreement

(Marked / Redline Format)

1.10 Scheduling.

1.10.1 General.

(a) The Office of the Interconnection shall administer scheduling processes to implement a Day-ahead Energy Market and a Real-time Energy Market. PJMSettlement shall be the Counterparty to the purchases and sales of energy that clear the Day-ahead Energy Market and the Real-time Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a Generating Market Buyer's self-schedule or self-supply of its generation resources up to that Generating Market Buyer's Equivalent Load.

(b) The Day-ahead Energy Market shall enable Market Participants to purchase and sell energy through the PJM Interchange Energy Market at Day-ahead Prices and enable Transmission Customers to reserve transmission service with Transmission Congestion Charges and Transmission Loss Charges based on locational differences in Day-ahead Prices. Up-to Congestion Transactions submitted in the Day-ahead Energy Market shall not require transmission service and Transmission Customers shall not reserve transmission service for such Up-to Congestion Transactions. Market Participants whose purchases and sales, and Transmission Customers whose transmission uses are scheduled in the Day-ahead Energy Market, shall be obligated to purchase or sell energy, or pay Transmission Congestion Charges and Transmission Loss Charges, at the applicable Day-ahead Prices for the amounts scheduled.

(c) In the Real-time Energy Market, Market Participants that deviate from the amounts of energy purchases or sales, or Transmission Customers that deviate from the transmission uses, scheduled in the Day-ahead Energy Market shall be obligated to purchase or sell energy, or pay Transmission Congestion Charges and Transmission Loss Charges, for the amount of the deviations at the applicable Real-time Prices or price differences, unless otherwise specified by this Schedule.

(d) The following scheduling procedures and principles shall govern the commitment of resources to the Day-ahead Energy Market and the Real-time Energy Market over a period extending from one week to one hour prior to the real-time dispatch. Scheduling encompasses the day-ahead and hourly scheduling process, through which the Office of the Interconnection determines the Day-ahead Energy Market and determines, based on changing forecasts of conditions and actions by Market Participants and system constraints, a plan to serve the hourly energy and reserve requirements of the Internal Market Buyers and the purchase requests of the External Market Buyers in the least costly manner, subject to maintaining the reliability of the PJM Region. Scheduling does not encompass Coordinated External Transactions, which are subject to the procedures of Section 1.13 of this Schedule 1 of this Agreement. Scheduling shall be conducted as specified in Section 1.10.1A below, subject to the following condition. If the Office of the Interconnection's forecast for the next seven days projects a likelihood of Emergency conditions, the Office of the Interconnection may commit, for all or part of such seven day period, to the use of generation resources with notification or start-up times greater than one day as necessary in order to alleviate or mitigate such Emergency, in accordance with the Market Sellers' offers for such units for such periods and the specifications in the PJM

Manuals. Such resources committed by the Office of the Interconnection to alleviate or mitigate an Emergency will not receive Operating Reserve Credits nor otherwise be made whole for its hours of operation for the duration of any portion of such commitment that exceeds the maximum start-up and notification times for such resources during Hot Weather Alerts and Cold Weather Alerts, consistent with Sections 3.2.3 and 6.6 hereof.

1.10.1A Day-ahead Energy Market Scheduling.

The following actions shall occur not later than 10:30 a.m. on the day before the Operating Day for which transactions are being scheduled, or such other deadline as may be specified by the Office of the Interconnection in order to comply with the practical requirements and the economic and efficiency objectives of the scheduling process specified in this Schedule.

(a) Each Market Participant may submit to the Office of the Interconnection specifications of the amount and location of its customer loads and/or energy purchases to be included in the Day-ahead Energy Market for each hour of the next Operating Day, such specifications to comply with the requirements set forth in the PJM Manuals. Each Market Buyer shall inform the Office of the Interconnection of the prices, if any, at which it desires not to include its load in the Day-ahead Energy Market rather than pay the Day-ahead Price. PRD Providers that have committed Price Responsive Demand in accordance with the Reliability Assurance Agreement shall submit to the Office of the Interconnection, in accordance with procedures specified in the PJM Manuals, any desired updates to their previously submitted PRD Curves, provided that such updates are consistent with their Price Responsive Demand commitments, and provided further that PRD Providers that are not Load Serving Entities for the Price Responsive Demand at issue may only submit PRD Curves for the Real-time Energy Market. Price Responsive Demand that has been committed in accordance with the Reliability Assurance Agreement shall be presumed available for the next Operating Day in accordance with the most recently submitted PRD Curve unless the PRD Curve is updated to indicate otherwise. PRD Providers may also submit PRD Curves for any Price Responsive Demand that is not committed in accordance with the Reliability Assurance Agreement; provided that PRD Providers that are not Load Serving Entities for the Price Responsive Demand at issue may only submit PRD Curves for the Real-time Energy Market. All PRD Curves shall be on a PRD Substation basis, and shall specify the maximum time period required to implement load reductions.

(b) Each Generating Market Buyer shall submit to the Office of the Interconnection: (i) hourly schedules for resource increments, including hydropower units, self-scheduled by the Market Buyer to meet its Equivalent Load; and (ii) the Dispatch Rate at which each such self-scheduled resource will disconnect or reduce output, or confirmation of the Market Buyer's intent not to reduce output.

(c) All Market Participants shall submit to the Office of the Interconnection schedules for any energy exports, energy imports, and wheel through transactions involving use of generation or Transmission Facilities as specified below, and shall inform the Office of the Interconnection if the transaction is to be scheduled in the Day-ahead Energy Market. Any Market Participant that elects to schedule an export, import or wheel through transaction in the Day-ahead Energy Market may specify the price (such price not to exceed the maximum price that may be specified

in the PJM Manuals), if any, at which the export, import or wheel through transaction will be wholly or partially curtailed. The foregoing price specification shall apply to the applicable interface pricing point. Any Market Participant that elects not to schedule its export, import or wheel through transaction in the Day-ahead Energy Market shall inform the Office of the Interconnection if the parties to the transaction are not willing to incur Transmission Congestion and Loss Charges in the Real-time Energy Market in order to complete any such scheduled transaction. Scheduling of such transactions shall be conducted in accordance with the specifications in the PJM Manuals and the following requirements:

i) Market Participants shall submit schedules for all energy purchases for delivery within the PJM Region, whether from resources inside or outside the PJM Region;

ii) Market Participants shall submit schedules for exports for delivery outside the PJM Region from resources within the PJM Region that are not Dynamic Transfers to such entities pursuant to Section 1.12; and

iii) In addition to the foregoing schedules for exports, imports and wheel through transactions, Market Participants shall submit confirmations of each scheduled transaction from each other party to the transaction in addition to the party submitting the schedule, or the adjacent Control Area.

(c-1) A Market Participant may elect to submit in the Day-ahead Energy Market a form 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. The Office of Interconnection will schedule these transactions only to the extent this difference in Locational Marginal Prices is within the maximum amount specified by the Market Participant. A Virtual Transaction of this type is referred to as an "Up-to Congestion Transaction." Such Up-to Congestion Transactions may be wholly or partially scheduled depending on the price difference between the source and sink locations in the Day-ahead Energy Market. The maximum difference between the source and sink prices that a participant may specify shall be limited to +/- $50/MWh. The foregoing price specification shall apply to the price difference between the specified source and sink in the day-ahead scheduling process only. An accepted Up-to Congestion Transaction results in scheduled injection at a specified source and scheduled withdrawal of the same megawatt quantity at a specified sink in the Day-ahead Energy Market.

(c-2) ~~The source-sink paths on which an~~ Up-to Congestion Transactions may only be submitted ~~are limited~~at hubs, Residual Metered Load and interfaces not described in Tariff, Attachment K-Appendix, section 2.6A(b). ~~to those paths posted on the PJM internet site and determined by the Office of the Interconnection using the following criteria:~~

~~Step 1: Start with the historic set of eligible nodes that were available as sources and sinks for interchange transactions on the PJM OASIS.~~

~~Step 2: Remove from the list of nodes described in Step 1 all load buses below 69 kV.~~

~~Step 3: Remove from the resulting set of nodes from Step 2 all generator buses at which no generators of 100 megawatts or more are connected.~~

~~Step 4: Remove from the results of Step 3 all electrically equivalent nodes.~~
Increment Offers and Decrement Bids may be only submitted at hubs, nodes at which physical generation or load is settled, Residual Metered Load and interfaces not described in Tariff, Attachment K-Appendix, section 2.6A(b).

(d) Market Sellers in the Day-ahead Energy Market shall submit offers for the supply of energy, demand reductions, or other services for the following Operating Day for each clock hour for which the Market Seller desires or is required to make its resource available to the Office of the Interconnection. Offers for the supply of energy may be cost-based, market-based, or both, and may vary hourly. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this Section 1.10.1A(d), Section 1.10.9B, Schedule 2 of the Operating Agreement, and the PJM Manuals, as applicable. Market Sellers owning or controlling the output of a Generation Capacity Resource that was committed in an FRR Capacity Plan, self-supplied, offered and cleared in a Base Residual Auction or Incremental Auction, or designated as replacement capacity, as specified in Attachment DD of the PJM Tariff, and that has not been rendered unavailable by a Generator Planned Outage, a Generator Maintenance Outage, or a Generator Forced Outage shall submit offers for the available capacity of such Generation Capacity Resource, including any portion that is self-scheduled by the Generating Market Buyer. Such offers shall be based on the ICAP equivalent of the Market Seller's cleared UCAP capacity commitment, provided, however, where the underlying resource is a Capacity Storage Resource or an Intermittent Resource, the Market Seller shall satisfy the must offer requirement by either self-scheduling or offering the unit as a dispatchable resource, in accordance with the PJM Manuals, where the hourly day-ahead self-scheduled values for such Capacity Storage Resources and Intermittent Resources may vary hour to hour from the capacity commitment. Any offer not designated as a Maximum Emergency offer shall be considered available for scheduling and dispatch under both Emergency and non-Emergency conditions. Offers may only be designated as Maximum Emergency offers to the extent that the Generation Capacity Resource falls into at least one of the following categories:

i) Environmental limits. If the resource has a limit on its run hours imposed by a federal, state, or other governmental agency that will significantly limit its availability, on either a temporary or long-term basis. This includes a resource that is limited to operating only during declared PJM capacity emergencies by a governmental authority.

ii) Fuel limits. If physical events beyond the control of the resource owner result in the temporary interruption of fuel supply and there is limited on-site fuel storage. A fuel supplier's exercise of a contractual right to interrupt supply or delivery under an interruptible service agreement shall not qualify as an event beyond the control of the resource owner.

iii) Temporary emergency conditions at the unit. If temporary emergency physical conditions at the resource significantly limit its availability.

iv) Temporary megawatt additions. If a resource can provide additional megawatts on a temporary basis by oil topping, boiler over-pressure, or similar techniques, and such megawatts are not ordinarily otherwise available.

The submission of offers for resource increments that have not cleared in a Base Residual Auction or an Incremental Auction, were not committed in an FRR Capacity Plan, and were not designated as replacement capacity under Attachment DD of the PJM Tariff shall be optional, but any such offers must contain the information specified in the Office of the Interconnection's Offer Data specification, Operating Agreement, Schedule 1, sections 1.10.1A(d), and 1.10.9B, Operating Agreement, Schedule 2, and the PJM Manuals, as applicable. Energy offered from generation resources that have not cleared a Base Residual Auction or an Incremental Auction, were not committed in an FRR Capacity Plan, and were not designated as replacement capacity under Attachment DD of the PJM Tariff shall not be supplied from resources that are included in or otherwise committed to supply the Operating Reserves of a Control Area outside the PJM Region.

The foregoing offers:

i) Shall specify the Generation Capacity Resource or Demand Resource and energy or demand reduction amount, respectively, for each clock hour in the offer period;

ii) Shall specify the amounts and prices for each clock hour during the entire Operating Day for each resource component offered by the Market Seller to the Office of the Interconnection;

iii) May specify for generation resources offer parameters for each clock hour during the entire Operating Day, as applicable and in accordance with section 1.10.9B below, including: (1) Minimum Run Time; (2) maximum run time; (3) Start-up Costs; (4) No-load Costs; (5) Incremental Energy Offer; (6) notification time; (7) availability; (8) ramp rate; (9) Economic Minimum; (10) Economic Maximum; (11) emergency minimum MW; and (12) emergency maximum MW, and may specify offer parameters for Demand Resources for each clock hour during the entire Operating Day, as applicable and in accordance with section 1.10.9B below, including: (1) minimum down time; (2) shutdown costs; (3) Incremental Energy Offer; (4) notification time; (5) Economic Minimum; and (6) Economic Maximum;

iv) Shall set forth any special conditions upon which the Market Seller proposes to supply a resource increment, including any curtailment rate

specified in a bilateral contract for the output of the resource, or any cancellation fees;

v) May include a schedule of offers for prices and operating data contingent on acceptance by the deadline specified in this Schedule, with additional schedules applicable if accepted after the foregoing deadline;

vi) Shall constitute an offer to submit the resource increment to the Office of the Interconnection for scheduling and dispatch in accordance with the terms of the offer for the clock hour, which offer shall remain open through the Operating Day, for which the offer is submitted, unless the Market Seller a) submits a Real-time Offer for the applicable clock hour, or b) updates the availability of its offer for that hour, as further described in the PJM Manuals;

vii) Shall be final as to the price or prices at which the Market Seller proposes to supply energy or other services to the PJM Interchange Energy Market, such price or prices being guaranteed by the Market Seller for the period extending through the end of the following Operating Day, unless modified after the close of the Day-ahead Energy Market as permitted pursuant to sections 1.10.9A or 1.10.9B below;

viii) Shall not exceed an energy offer price of $1,000/megawatt-hour for all generation resources, except (1) when a Market Seller's cost-based offer is above $1,000/megawatt-hour and less than or equal to $2,000/megawatt-hour, then its market-based offer must be less than or equal to the cost-based offer; and (2) when a Market Seller's cost-based offer is greater than $2,000/megawatt-hour, then its market-based offer must be less than or equal to $2,000/megawatt-hour; and

ix) Shall not exceed a *demand reduction* offer price of $1,000/megawatt-hour, *except when an Economic Load Response Participant, an Emergency Load Response participant, or a Pre-Emergency Load Response participant submits a cost-based offer that includes an incremental cost component that is above $1,000/megawatt-hour, then its market-based offer must be less than or equal to the cost-based offer but in no event greater than $2,000/megawatt-hour; and*

x) Shall not exceed an energy offer price of $0.00/MWh for pumped storage hydropower units scheduled by the Office of the Interconnection pursuant to the hydro optimization tool in the Day-ahead Energy Market.

(e) A Market Seller that wishes to make a resource available to sell Regulation service shall submit an offer for Regulation for each clock hour for which the Market Seller desires to make its resource available to the Office of the Interconnection to provide Regulation that shall specify

the megawatts of Regulation being offered, which must equal or exceed 0.1 megawatts, the Regulation Zone for which such Regulation is offered, the price of the capability offer in dollars per MW, the price of the performance offer in Dollars per change in MW, and such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer and the resource's opportunity costs. Such offers may vary hourly, and may be updated each hour, up to 65 minutes before the applicable clock hour during the Operating Day. The total of the performance offer multiplied by the historical average mileage used in the market clearing plus the capability offer shall not exceed $100/megawatt-hour in the case of Regulation offered for all Regulation Zones. In addition to any market-based offer for Regulation, the Market Seller also shall submit a cost-based offer. A cost-based offer must be in the form specified in the PJM Manuals and consist of the following components as well as any other components specified in the PJM Manuals:

i. The costs (in $/MW) of the fuel cost increase due to the steady-state heat rate increase resulting from operating the unit at lower megawatt output incurred from the provision of Regulation shall apply to the capability offer;

ii. The cost increase (in $/ΔMW) in costs associated with movement of the regulation resource incurred from the provision of Regulation shall apply to the performance offer; and

iii. An adder of up to $12.00 per megawatt of Regulation provided applied to the capability offer.

Qualified Regulation capability must satisfy the measurement and verification tests specified in the PJM Manuals.

(f) Each Market Seller owning or controlling the output of a Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative shall submit a forecast of the availability of each such Generation Capacity Resource for the next seven days. A Market Seller (i) may submit a non-binding forecast of the price at which it expects to offer a generation resource increment to the Office of the Interconnection over the next seven days, and (ii) shall submit a binding offer for energy, along with Start-up Costs and No-load Costs, if any, for the next seven days or part thereof, for any generation resource with minimum notification or start-up requirement greater than 24 hours. Such resources committed by the Office of the Interconnection will not receive Operating Reserve Credits nor otherwise be made whole for its hours of operation for the duration of any portion of such commitment that exceeds the maximum start-up and notification times for such resources during Hot Weather Alerts and Cold Weather Alerts, consistent with Sections 3.2.3 and 6.6 hereof.

(g) Each component of an offer by a Market Seller of a Generation Capacity Resource that is constant for the entire Operating Day and does not vary hour to hour shall remain in effect for subsequent Operating Days until superseded or canceled.

(h) The Office of the Interconnection shall post the total hourly loads scheduled in the Day-ahead Energy Market, as well as, its estimate of the combined hourly load of the Market Buyers for the next four days, and peak load forecasts for an additional three days.

(i) Except for Economic Load Response Participants, all Market Participants may submit Virtual Transactions that apply to the Day-ahead Energy Market only. Such Virtual Transactions must comply with the requirements set forth in the PJM Manuals and must specify amount, location and price, if any, at which the Market Participant desires to purchase or sell energy in the Day-ahead Energy Market. The Office of the Interconnection may require that a market participant shall not submit in excess of a defined number of bid/offer segments in the Day-ahead Energy Market, as specified in the PJM Manuals, when the Office of the Interconnection determines that such limit is required to avoid or mitigate significant system performance problems related to bid/offer volume. Notice of the need to impose such limit shall be provided prior to 10:00 a.m. EPT on the day that the Day-ahead Energy Market will clear. For purposes of this provision, a bid/offer segment is each pairing of price and megawatt quantity submitted as part of an Increment Offer or Decrement Bid. For purposes of applying this provision to an Up-to Congestion Transaction, a bid/offer segment shall refer to the pairing of a source and sink designation, as well as price and megawatt quantity, that comprise each Up-to Congestion Transaction.

(j) A Market Seller that wishes to make a generation resource or Demand Resource available to sell Synchronized Reserve shall submit an offer for Synchronized Reserve for each clock hour for which the Market Seller desires or is required to make its resource available to the Office of the Interconnection to provide Synchronized Reserve that shall specify the megawatts of Synchronized Reserve being offered, which must equal or exceed 0.1 megawatts, the price of the offer in dollars per megawatt hour, and such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer and the energy used by the generation resource to provide the Synchronized Reserve and the generation resource's unit specific opportunity costs. Such offers may vary hourly, and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day. The price of the offer shall not exceed the variable operating and maintenance costs for providing Synchronized Reserve plus seven dollars and fifty cents.

(k) An Economic Load Response Participant that wishes to participate in the Day-ahead Energy Market by reducing demand shall submit an offer to reduce demand to the Office of the Interconnection for each clock hour for which the Economic Load Response Participant desires to make its resource available to the Office of the Interconnection to reduce demand. The offer must equal or exceed 0.1 megawatts, may vary hourly, and shall specify: (i) the amount of the offered curtailment in minimum increments of .1 megawatts: (ii) the Day-ahead Locational Marginal Price above which the end-use customer will reduce load, subject to section 1.10.1A(d)(ix); and (iii) at the Economic Load Response Participant's option, start-up costs associated with reducing load, including direct labor and equipment costs, opportunity costs, and/or a minimum of number of contiguous hours for which the load reduction must be committed. Such offers may be updated each hour, up to 65 minutes before the applicable clock hour during the Operating Day. Economic Load Response Participants submitting offers to

reduce demand in the Day-ahead Energy Market may establish an incremental offer curve, provided that such offer curve shall be limited to ten price pairs (in MWs) per hour.

(l) Market Sellers owning or controlling the output of a Demand Resource that was committed in an FRR Capacity Plan, or that was self-supplied or that offered and cleared in a Base Residual Auction or Incremental Auction, may submit demand reduction bids for the available load reduction capability of the Demand Resource. The submission of demand reduction bids for Demand Resource increments that were not committed in an FRR Capacity Plan, or that have not cleared in a Base Residual Auction or Incremental Auction, shall be optional, but any such bids must contain the information required to be included in such bids, as specified in the PJM Economic Load Response Program. A Demand Resource that was committed in an FRR Capacity Plan, or that was self-supplied or offered and cleared in a Base Residual Auction or Incremental Auction, may submit a demand reduction bid in the Day-ahead Energy Market as specified in the Economic Load Response Program; provided, however, that in the event of an Emergency PJM shall require Demand Resources to reduce load, notwithstanding that the Zonal LMP at the time such Emergency is declared is below the price identified in the demand reduction bid.

(m) Market Sellers providing Day-ahead Scheduling Reserves Resources shall submit in the Day-ahead Scheduling Reserves Market: 1) a price offer in dollars per megawatt hour; and 2) such other information specified by the Office of the Interconnection as may be necessary to determine any relevant opportunity costs for the resource(s). The foregoing notwithstanding, to qualify to submit Day-ahead Scheduling Reserves pursuant to this section, the Day-ahead Scheduling Reserves Resources shall submit energy offers in the Day-ahead Energy Market including start-up and shut-down costs for generation resource and Demand Resources, respectively, and all generation resources that are capable of providing Day-ahead Scheduling Reserves that a particular resource can provide that service. The megawatt quantity of Day-ahead Scheduling Reserves that a particular resource can provide in a given hour will be determined based on the energy Offer Data submitted in the Day-ahead Energy Market, as detailed in the PJM Manuals.

1.10.1B Demand Bid Scheduling and Screening

(a) The Office of the Interconnection shall apply Demand Bid Screening to all Demand Bids submitted in the Day-ahead Energy Market for each Load Serving Entity, separately by Zone. Using Demand Bid Screening, the Office of the Interconnection will automatically reject a Load Serving Entity's Demand Bids in any future Operating Day for which the Load Serving Entity submits bids if the total megawatt volume of such bids would exceed the Load Serving Entity's Demand Bid Limit for any hour in such Operating Day, unless the Office of the Interconnection permits an exception pursuant to subsection (d) below.

(b) On a daily basis, PJM will update and post each Load Serving Entity's Demand Bid Limit in each applicable Zone. Such Demand Bid Limit will apply to all Demand Bids submitted by that Load Serving Entity for each future Operating Day for which it submits bids. The Demand Bid Limit is calculated using the following equation:

Demand Bid Limit = greater of (Zonal Peak Demand Reference Point * 1.3), or (Zonal Peak Demand Reference Point + 10MW)

Where:

1. Zonal Peak Demand Reference Point = for each Zone: the product of (a) LSE Recent Load Share, multiplied by (b) Peak Daily Load Forecast.
2. LSE Recent Load Share is the Load Serving Entity's highest share of Network Load in each Zone for any hour over the most recently available seven Operating Days for which PJM has data.
3. Peak Daily Load Forecast is PJM's highest available peak load forecast for each applicable Zone that is calculated on a daily basis.

(c) A Load Serving Entity whose Demand Bids are rejected as a result of Demand Bid Screening may change its Demand Bids to reduce its total megawatt volume to a level that does not exceed its Demand Bid Limit, and may resubmit them subject to the applicable rules related to bid submission outlined in Tariff, Operating Agreement and PJM Manuals.

(d) PJM may allow a Load Serving Entity to submit bids in excess of its Demand Bid Limit when circumstances exist that will cause, or are reasonably expected to cause, a Load Serving Entity's actual load to exceed its Demand Bid Limit on a given Operating Day. Examples of such circumstances include, but are not limited to, changes in load commitments due to state sponsored auctions, mergers and acquisitions between PJM Members, and sales and divestitures between PJM Members. A Load Serving Entity may submit a written exception request to the Office of Interconnection for a higher Demand Bid Limit for an affected Operating Day. Such request must include a detailed explanation of the circumstances at issue and supporting documentation that justify the Load Serving Entity's expectation that its actual load will exceed its Demand Bid Limit.

1.10.2 Pool-scheduled Resources.

Pool-scheduled resources are those resources for which Market Participants submitted offers to sell energy in the Day-ahead Energy Market and offers to reduce demand in the Day-ahead Energy Market, which the Office of the Interconnection scheduled in the Day-ahead Energy Market as well as generators committed by the Office of the Interconnection subsequent to the Day-ahead Energy Market. Such resources shall be committed to provide energy in the real-time dispatch unless the schedules for such units are revised pursuant to Sections 1.10.9 or 1.11. Pool-scheduled resources shall be governed by the following principles and procedures.

(a) Pool-scheduled resources shall be selected by the Office of the Interconnection on the basis of the prices offered for energy and demand reductions and related services, whether the resource is expected to be needed to maintain system reliability during the Operating Day, Start-up Costs, No-load Costs, and cancellation fees, and the specified operating characteristics, offered by Market Sellers to the Office of the Interconnection by the offer deadline specified in Section 1.10.1A. Hydropower units can only be pool-scheduled if they are pumped storage units and scheduled by the Office of the Interconnection pursuant to the hydro optimization tool in the Day-ahead Energy Market.

(b) A resource that is scheduled by a Market Participant to support a bilateral sale, or that is self-scheduled by a Generating Market Buyer, shall not be selected by the Office of the Interconnection as a pool-scheduled resource except in an Emergency.

(c) Market Sellers offering energy from hydropower or other facilities with fuel or environmental limitations may submit data to the Office of the Interconnection that is sufficient to enable the Office of the Interconnection to determine the available operating hours of such facilities.

(d) The Market Seller of a resource selected as a pool-scheduled resource shall receive payments or credits for energy, demand reductions or related services, or for Start-up Costs and No-load Costs, from the Office of the Interconnection on behalf of the Market Buyers in accordance with Section 3 of this Schedule 1. Alternatively, the Market Seller shall receive, in lieu of Start-up Costs and No-load Costs, its actual costs incurred, if any, up to a cap of the resource's Start-up Costs, if the Office of the Interconnection cancels its selection of the resource as a pool-scheduled resource and so notifies the Market Seller before the resource is synchronized.

(e) Market Participants shall make available their pool-scheduled resources to the Office of the Interconnection for coordinated operation to supply the Operating Reserves needs of the applicable Control Zone.

(f) Economic Load Response Participants offering to reduce demand shall specify: (i) the amount of the offered curtailment, which offer must equal or exceed 0.1 megawatts, in minimum increments of .1 megawatts; (ii) the real-time Locational Marginal Price above which the end-use customer will reduce load; and (iii) at the Economic Load Response Participant's option, shut-down costs associated with reducing load, including direct labor and equipment costs, opportunity costs, and/or a minimum number of contiguous hours for which the load reduction must be committed. Economic Load Response Participants submitting offers to reduce demand in the Real-time Energy Market may establish an incremental offer curve, provided that such offer curve shall be limited to ten price pairs (in MWs). Economic Load Response Participants offering to reduce demand shall also indicate the hours that the demand reduction is not available.

1.10.3 Self-scheduled Resources.

Self-scheduled resources shall be governed by the following principles and procedures.

(a) Each Generating Market Buyer shall use all reasonable efforts, consistent with Good Utility Practice, not to self-schedule resources in excess of its Equivalent Load.

(b) The offered prices of resources that are self-scheduled, or otherwise not following the dispatch orders of the Office of the Interconnection, shall not be considered by the Office of the Interconnection in determining Locational Marginal Prices.

(c) Market Participants shall make available their self-scheduled resources to the Office of the Interconnection for coordinated operation to supply the Operating Reserves needs of the applicable Control Zone, by submitting an offer as to such resources.

(d) A Market Participant self-scheduling a resource in the Day-ahead Energy Market that does not deliver the energy in the Real-time Energy Market, shall replace the energy not delivered with energy from the Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

(e) Hydropower units, excluding pumped storage units, may only be self-scheduled.

1.10.4 Capacity Resources.

(a) A Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative that is selected as a pool-scheduled resource shall be made available for scheduling and dispatch at the direction of the Office of the Interconnection. Such a Generation Capacity Resource that does not deliver energy as scheduled shall be deemed to have experienced a Generator Forced Outage to the extent of such energy not delivered. A Market Participant offering such Generation Capacity Resource in the Day-ahead Energy Market shall replace the energy not delivered with energy from the Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

(b) Energy from a Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative that has not been scheduled in the Day-ahead Energy Market may be sold on a bilateral basis by the Market Seller, may be self-scheduled, or may be offered for dispatch during the Operating Day in accordance with the procedures specified in this Schedule. Such a Generation Capacity Resource that has not been scheduled in the Day-ahead Energy Market and that has been sold on a bilateral basis must be made available upon request to the Office of the Interconnection for scheduling and dispatch during the Operating Day if the Office of the Interconnection declares a Maximum Generation Emergency. Any such resource so scheduled and dispatched shall receive the applicable Real-time Price for energy delivered.

(c) A resource that has been self-scheduled shall not receive payments or credits for Start-up Costs or No-load Costs.

1.10.5 External Resources.

(a) External Resources may submit offers to the PJM Interchange Energy Market, in accordance with the day-ahead and real-time scheduling processes specified above. An External Resource selected as a pool-scheduled resource shall be made available for scheduling and dispatch at the direction of the Office of the Interconnection, and except as specified below shall be compensated on the same basis as other pool-scheduled resources. External Resources that are not capable of Dynamic Transfer shall, if selected by the Office of the Interconnection on the basis of the Market Seller's Offer Data, be block loaded on an hourly scheduled basis. Market

Sellers shall offer External Resources to the PJM Interchange Energy Market on either a resource-specific or an aggregated resource basis. A Market Participant whose pool-scheduled resource does not deliver the energy scheduled in the Day-ahead Energy Market shall replace such energy not delivered as scheduled in the Day-ahead Energy Market with energy from the PJM Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

(b) Offers for External Resources from an aggregation of two or more generating units shall so indicate, and shall specify, in accordance with the Offer Data requirements specified by the Office of the Interconnection: (i) energy prices; (ii) hours of energy availability; (iii) a minimum dispatch level; (iv) a maximum dispatch level; and (v) unless such information has previously been made available to the Office of the Interconnection, sufficient information, as specified in the PJM Manuals, to enable the Office of the Interconnection to model the flow into the PJM Region of any energy from the External Resources scheduled in accordance with the Offer Data.

(c) Offers for External Resources on a resource-specific basis shall specify the resource being offered, along with the information specified in the Offer Data as applicable.

1.10.6 External Market Buyers.

(a) Deliveries to an External Market Buyer not subject to Dynamic Transfer by the Office of the Interconnection shall be delivered on a block loaded basis to the bus or buses at the electrical boundaries of the PJM Region, or in such area with respect to an External Market Buyer's load within such area not served by Network Service, at which the energy is delivered to or for the External Market Buyer. External Market Buyers shall be charged (which charge may be positive or negative) at either the Day-ahead Prices or Real-time Prices, whichever is applicable, for energy at the foregoing bus or buses.

(b) An External Market Buyer's hourly schedules for energy purchased from the PJM Interchange Energy Market shall conform to the ramping and other applicable requirements of the interconnection agreement between the PJM Region and the Control Area to which, whether as an intermediate or final point of delivery, the purchased energy will initially be delivered.

(c) The Office of the Interconnection shall curtail deliveries to an External Market Buyer if necessary to maintain appropriate reserve levels for a Control Zone as defined in the PJM Manuals, or to avoid shedding load in such Control Zone.

1.10.6A Transmission Loading Relief Customers.

(a) An entity that desires to elect to pay Transmission Congestion Charges in order to continue its energy schedules during an Operating Day over contract paths outside the PJM Region in the event that PJM initiates Transmission Loading Relief that otherwise would cause PJM to request security coordinators to curtail such Member's energy schedules shall:

(i) enter its election on OASIS by 10:30 a.m. of the day before the Operating Day, in accordance with procedures established by PJM, which election shall be applicable for the entire Operating Day; and

(ii) if PJM initiates Transmission Loading Relief, provide to PJM, at such time and in accordance with procedures established by PJM, the hourly integrated energy schedules that impacted the PJM Region (as indicated from the NERC Interchange Distribution Calculator) during the Transmission Loading Relief.

(b) If an entity has made the election specified in Section (a), then PJM shall not request security coordinators to curtail such entity's energy transactions, except as may be necessary to respond to Emergencies.

(c) In order to make elections under this Section 1.10.6A, an entity must (i) have met the creditworthiness standards established by the Office of the Interconnection or provided a letter of credit or other form of security acceptable to the Office of the Interconnection, and (ii) have executed either the Agreement, a Service Agreement under the PJM Tariff, or other agreement committing to pay all Transmission Congestion Charges incurred under this Section.

1.10.7 Bilateral Transactions.

Bilateral transactions as to which the parties have notified the Office of the Interconnection by the deadline specified in Section 1.10.1A that they elect not to be included in the Day-ahead Energy Market and that they are not willing to incur Transmission Congestion Charges in the Real-time Energy Market shall be curtailed by the Office of the Interconnection as necessary to reduce or alleviate transmission congestion. Bilateral transactions that were not included in the Day-ahead Energy Market and that are willing to incur congestion charges and bilateral transactions that were accepted in the Day-ahead Energy Market shall continue to be implemented during periods of congestion, except as may be necessary to respond to Emergencies.

1.10.8 Office of the Interconnection Responsibilities.

(a) The Office of the Interconnection shall use its best efforts to determine (i) the least-cost means of satisfying the projected hourly requirements for energy, Operating Reserves, and other ancillary services of the Market Buyers, including the reliability requirements of the PJM Region, of the Day-ahead Energy Market, and (ii) the least-cost means of satisfying the Operating Reserve and other ancillary service requirements for any portion of the load forecast of the Office of the Interconnection for the Operating Day in excess of that scheduled in the Day-ahead Energy Market. In making these determinations, the Office of the Interconnection shall take into account: (i) the Office of the Interconnection's forecasts of PJM Interchange Energy Market and PJM Region energy requirements, giving due consideration to the energy requirement forecasts and purchase requests submitted by Market Buyers and PRD Curves properly submitted by Load Serving Entities for the Price Responsive Demand loads they serve; (ii) the offers submitted by Market Sellers; (iii) the availability of limited energy resources; (iv) the capacity, location, and other relevant characteristics of self-scheduled resources; (v) the objectives of each Control Zone for Operating Reserves, as specified in the PJM Manuals; (vi) the requirements of each Regulation Zone for Regulation and other ancillary services, as

specified in the PJM Manuals; (vii) the benefits of avoiding or minimizing transmission constraint control operations, as specified in the PJM Manuals; and (viii) such other factors as the Office of the Interconnection reasonably concludes are relevant to the foregoing determination, including, without limitation, transmission constraints on external coordinated flowgates to the extent provided by section 1.7.6. The Office of the Interconnection shall develop a Day-ahead Energy Market based on the foregoing determination, and shall determine the Day-ahead Prices resulting from such schedule. The Office of the Interconnection shall report the planned schedule for a hydropower resource to the operator of that resource as necessary for plant safety and security, and legal limitations on pond elevations.

(b) By 1:30 p.m., or as soon as practicable thereafter, of the day before each Operating Day, or such other deadline as may be specified by the Office of the Interconnection in the PJM Manuals, the Office of the Interconnection shall: (i) post the aggregate Day-ahead Energy Market results; (ii) post the Day-ahead Prices; and (iii) inform the Market Sellers, Market Buyers, and Economic Load Response Participants of their scheduled injections, withdrawals, and demand reductions respectively. The foregoing notwithstanding, the deadlines set forth in this subsection shall not apply if the Office of the Interconnection is unable to obtain Market Participant bid/offer data due to extraordinary circumstances. For purposes of this subsection, extraordinary circumstances shall mean a technical malfunction that limits, prohibits or otherwise interferes with the ability of the Office of the Interconnection to obtain Market Participant bid/offer data prior to 11:59 p.m. on the day before the affected Operating Day. Extraordinary circumstances do not include a Market Participant's inability to submit bid/offer data to the Office of the Interconnection. If the Office of the Interconnection is unable to clear the Day-ahead Energy Market prior to 11:59 p.m. on the day before the affected Operating Day as a result of such extraordinary circumstances, the Office of the Interconnection shall notify Members as soon as practicable.

(c) Following posting of the information specified in Section 1.10.8(b), and absent extraordinary circumstances preventing the clearing of the Day-ahead Energy Market, the Office of the Interconnection shall revise its schedule of generation resources to reflect updated projections of load, conditions affecting electric system operations in the PJM Region, the availability of and constraints on limited energy and other resources, transmission constraints, and other relevant factors.

(d) Market Buyers shall pay PJMSettlement and Market Sellers shall be paid by PJMSettlement for the quantities of energy scheduled in the Day-ahead Energy Market at the Day-ahead Prices when the Day-ahead Price is positive. Market Buyers shall be paid by PJMSettlement and Market Sellers shall pay PJMSettlement for the quantities of energy scheduled in the Day-ahead Energy Market at the Day-ahead Prices when the Day-ahead Price is negative. Economic Load Response Participants shall be paid for scheduled demand reductions pursuant to Section 3.3A of this Schedule. Notwithstanding the foregoing, if the Office of the Interconnection is unable to clear the Day-ahead Energy Market prior to 11:59 p.m. on the day before the affected Operating Day due to extraordinary circumstances as described in subsection (b) above, no settlements shall be made for the Day-ahead Energy Market, no scheduled megawatt quantities shall be established, and no Day-ahead Prices shall be established for that Operating Day. Rather, for purposes of settlements for such Operating Day, the Office of the

Interconnection shall utilize a scheduled megawatt quantity and price of zero and all settlements, including Financial Transmission Right Target Allocations, will be based on the real-time quantities and prices as determined pursuant to Sections 2.4 and 2.5 hereof.

(e) If the Office of the Interconnection discovers an error in prices and/or cleared quantities in the Day-ahead Energy Market, Real-time Energy Market, Ancillary Services Markets or Day Ahead Scheduling Reserve Market after it has posted the results for these markets on its Web site, the Office of the Interconnection shall notify Market Participants of the error as soon as possible after it is found, but in no event later than 12:00 p.m. of the second Business Day following the Operating Day for the Ancillary Services Markets and Real-time Energy Market, and no later than 5:00 p.m. of the second Business Day following the initial publication of the results for the Day-ahead Scheduling Reserve Market and Day-ahead Energy Market. After this initial notification, if the Office of the Interconnection determines it is necessary to post modified results, it shall provide notification of its intent to do so, together with all available supporting documentation, by no later than 5:00 p.m. of the fifth Business Day following the Operating Day for the Ancillary Services Markets and Real-time Energy Market, and no later than 5:00 p.m. of the fifth Business Day following the initial publication of the results in the Day-ahead Scheduling Reserve Market and the Day-ahead Energy Market. Thereafter, the Office of the Interconnection must post on its Web site the corrected results by no later than 5:00 p.m. of the tenth calendar day following the Operating Day for the Ancillary Services Markets, Day-ahead Energy Market and Real-time Energy Market, and no later than 5:00 p.m. of the tenth calendar day following the initial publication of the results in the Day-ahead Scheduling Reserve Market. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced market results are under publicly noticed review by the FERC.

(f) Consistent with Section 18.17.1 of the PJM Operating Agreement, and notwithstanding anything to the contrary in the Operating Agreement or in the PJM Tariff, to allow the tracking of Market Participants' non-aggregated bids and offers over time as required by FERC Order No. 719, the Office of the Interconnection shall post on its Web site the non-aggregated bid data and Offer Data submitted by Market Participants (for participation in the PJM Interchange Energy Market) approximately four months after the bid or offer was submitted to the Office of the Interconnection.

1.10.9 Hourly Scheduling.

(a) Following the initial posting by the Office of the Interconnection of the Locational Marginal Prices resulting from the Day-ahead Energy Market, and subject to the right of the Office of the Interconnection to schedule and dispatch pool-scheduled resources and to direct that schedules be changed in an Emergency, and absent extraordinary circumstances preventing the clearing of the Day-ahead Energy Market, a generation rebidding period shall exist. Typically the rebidding period shall be from the time the Office of the Interconnection posts the results of the Day-ahead Energy Market until 2:15 p.m. on the day before each Operating Day. However, should the clearing of the Day-ahead Energy Market be significantly delayed, the Office of the Interconnection may establish a revised rebidding period. During the rebidding

period, Market Participants may submit revisions to generation Offer Data for the next Operating Day. Adjustments to the Day-ahead Energy Market shall be settled at the applicable Real-time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-ahead Energy Market at the applicable Day-ahead Prices.

(b) A Market Participant may adjust the schedule of a resource under its dispatch control on an hour-to-hour basis beginning at 10:00 p.m. of the day before each Operating Day, provided that the Office of the Interconnection is notified not later than 65 minutes prior to the hour in which the adjustment is to take effect, as follows and as specified in section 1.10.9A of this Schedule:

i) A Generating Market Buyer may self-schedule any of its resource increments, including hydropower resources, not previously designated as self-scheduled and not selected as a pool-scheduled resource in the Day-ahead Energy Market;

ii) A Market Participant may request the scheduling of a non-firm bilateral transaction; or

iii) A Market Participant may request the scheduling of deliveries or receipts of Spot Market Energy; or

iv) A Generating Market Buyer may remove from service a resource increment, including a hydropower resource, that it had previously designated as self-scheduled, provided that the Office of the Interconnection shall have the option to schedule energy from any such resource increment that is a Capacity Resource at the price offered in the scheduling process, with no obligation to pay any Start-Up Costs.

(c) An External Market Buyer may refuse delivery of some or all of the energy it requested to purchase in the Day-ahead Energy Market by notifying the Office of the Interconnection of the adjustment in deliveries not later than 65 minutes prior to the hour in which the adjustment is to take effect, but any such adjustment shall not affect the obligation of the External Market Buyer to pay for energy scheduled on its behalf in the Day-ahead Energy Market at the applicable Day-ahead Prices.

(d) The Office of the Interconnection shall provide External Market Buyers and External Market Sellers and parties to bilateral transactions with any revisions to their schedules resulting from the rebidding period by 6:30 p.m. on the day before each Operating Day. The Office of the Interconnection may also commit additional resources after such time as system conditions require. For each hour in the Operating Day, as soon as practicable after the deadlines specified in the foregoing subsection of this Section 1.10, the Office of the Interconnection shall provide External Market Buyers and External Market Sellers and parties to bilateral transactions with any revisions to their schedules for the hour.

1.10.9A Updating Offers in Real-time

(a) Each Market Seller may submit Real-time Offers for a resource up to 65 minutes before the applicable clock hour, and such Real-time Offers shall supersede any previous offer for that resource for the clock hour, as further described in the PJM Manuals and subject to the following conditions:

(*i*) A market-based Real-time Offer shall not exceed the applicable energy offer caps specified in this Schedule. Once a Market Seller's resource is committed for an applicable clock hour, the Market Seller may not increase its Incremental Energy Offer and may only submit a market-based Real-time Offer that is higher than its market-based offer that was in effect at the time of commitment to reflect increases in the resource's cost-based Start-up Costs and cost-based No-load Costs. The Market Seller may elect not to have its market-based offer considered for dispatch and to have only its lowest cost-based offer considered for the remainder of the Operating Day.

(*ii*) Cost-based Real-time Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection's Offer Data specification, Operating Agreement, Schedule 1, sections 1.10.1A(d) and 1.10.9B, Operating Agreement, Schedule 2 and the PJM Manuals, as applicable. If a Market Seller submits a market-based Real-time Offer for a particular clock hour in accordance with subsection (c) below, or if updates to a cost-based offer are required by the Market Seller's approved Fuel Cost Policy, the Market Seller shall update its previously submitted cost-based Real-time Offer.

(*iii*) If a Market Seller's available cost-based offer is not compliant with Operating Agreement, Schedule 2 and the PJM Manuals at the time a Market Seller submits a market-based Real-time Offer for an applicable clock hour during the Operating Day, the Market Seller must submit an updated cost-based Real-time Offer consisting of an Incremental Energy Offer, Start-up Cost, and No-load Cost for that clock hour that is compliant with Operating Agreement, Schedule 2 and the PJM Manuals.

(b) Each Market Seller may submit Real-time Offers for a resource during and through the end of the applicable clock hour to update only the following offer parameters, as further described in the PJM Manuals: (1) Economic Minimum; (2) Economic Maximum; (3) emergency minimum MW; (4) emergency maximum MW; (5) unit availability status; and (6) fixed output indicator. Such Real-time Offers shall supersede any previous offer for that resource for the clock hour.

1.10.9B Offer Parameter Flexibility

(a) Market Sellers may, in accordance with sections 1.10.1A and 1.10.9A above, this section 1.10.9B, and the PJM Manuals, update offer parameters at any time up to 65 minutes before the applicable clock hour, including prior to the close of the Day-ahead Energy Market and prior to the close of the rebidding period specified in section 1.10.9, except that Market Sellers may not update their offers for the supply of energy or demand reduction: (1) during the period after the close the Day-ahead Energy Market and prior to the posting of the Day-ahead Energy Market results pursuant to section 1.10.8(b); or (2) during the period after close of the rebidding period and prior to PJM announcing the results of the rebidding period pursuant to section 1.10.9(d).

(b) For generation resource offers, Market Sellers may vary for each clock hour during the entire Operating Day the following offer parameters: (1) cost-based Start-up Costs; (2) cost-based No-load Costs; (3) Incremental Energy Offer; (4) Economic Minimum and Economic Maximum; (5) emergency minimum MW and emergency maximum MW; and (6) for Real-time Offers only, *(i)* notification time and *(ii) for uncommitted hours only,* Minimum Run Time.

(c) For Demand Resource offers, Market Sellers may vary for each clock hour during the entire Operating Day the following offer parameters: (1) shutdown costs, (2) Incremental Energy Offer; (3) Economic Minimum; (4) Economic Maximum; and (5) for Real-time Offers only, *(i)* notification time and *(ii) for uncommitted hours only,* minimum down time.

(d) After the announcement of the results of the rebidding period pursuant to section 1.10.9(d), *a* Market Seller may submit a Real-time Offer where offer parameters *may differ from the offer originally submitted in the Day-ahead Energy Market, except that a Market Seller may not submit a Real-time Offer that changes, of the offer parameters listed in section 1.10.1A(d), the* MW amounts specified in the Incremental Energy Offer, *ramp rate, maximum run time,* and availability*; provided, however, Market Sellers of dual-fueled resources may submit Real-time Offers for such resources that change the availability of a submitted cost-based offer.*

Attachment B

PJM Open Access Transmission Tariff
and PJM Operating Agreement

(Clean Format)

Section(s) of the
PJM Open Access Transmission Tariff

(Clean Format)

1.10 Scheduling.

1.10.1 General.

(a) The Office of the Interconnection shall administer scheduling processes to implement a Day-ahead Energy Market and a Real-time Energy Market. PJMSettlement shall be the Counterparty to the purchases and sales of energy that clear the Day-ahead Energy Market and the Real-time Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a Generating Market Buyer's self-schedule or self-supply of its generation resources up to that Generating Market Buyer's Equivalent Load.

(b) The Day-ahead Energy Market shall enable Market Participants to purchase and sell energy through the PJM Interchange Energy Market at Day-ahead Prices and enable Transmission Customers to reserve transmission service with Transmission Congestion Charges and Transmission Loss Charges based on locational differences in Day-ahead Prices. Up-to Congestion Transactions submitted in the Day-ahead Energy Market shall not require transmission service and Transmission Customers shall not reserve transmission service for such Up-to Congestion Transactions. Market Participants whose purchases and sales, and Transmission Customers whose transmission uses are scheduled in the Day-ahead Energy Market, shall be obligated to purchase or sell energy, or pay Transmission Congestion Charges and Transmission Loss Charges, at the applicable Day-ahead Prices for the amounts scheduled.

(c) In the Real-time Energy Market, Market Participants that deviate from the amounts of energy purchases or sales, or Transmission Customers that deviate from the transmission uses, scheduled in the Day-ahead Energy Market shall be obligated to purchase or sell energy, or pay Transmission Congestion Charges and Transmission Loss Charges, for the amount of the deviations at the applicable Real-time Prices or price differences, unless otherwise specified by this Schedule.

(d) The following scheduling procedures and principles shall govern the commitment of resources to the Day-ahead Energy Market and the Real-time Energy Market over a period extending from one week to one hour prior to the real-time dispatch. Scheduling encompasses the day-ahead and hourly scheduling process, through which the Office of the Interconnection determines the Day-ahead Energy Market and determines, based on changing forecasts of conditions and actions by Market Participants and system constraints, a plan to serve the hourly energy and reserve requirements of the Internal Market Buyers and the purchase requests of the External Market Buyers in the least costly manner, subject to maintaining the reliability of the PJM Region. Scheduling does not encompass Coordinated External Transactions, which are subject to the procedures of Section 1.13 of this Schedule 1 of this Agreement. Scheduling shall be conducted as specified in Section 1.10.1A below, subject to the following condition. If the Office of the Interconnection's forecast for the next seven days projects a likelihood of Emergency conditions, the Office of the Interconnection may commit, for all or part of such seven day period, to the use of generation resources with notification or start-up times greater than one day as necessary in order to alleviate or mitigate such Emergency, in accordance with the Market Sellers' offers for such units for such periods and the specifications in the PJM

Manuals. Such resources committed by the Office of the Interconnection to alleviate or mitigate an Emergency will not receive Operating Reserve Credits nor otherwise be made whole for its hours of operation for the duration of any portion of such commitment that exceeds the maximum start-up and notification times for such resources during Hot Weather Alerts and Cold Weather Alerts, consistent with Sections 3.2.3 and 6.6 hereof.

1.10.1A Day-ahead Energy Market Scheduling.

The following actions shall occur not later than 10:30 a.m. on the day before the Operating Day for which transactions are being scheduled, or such other deadline as may be specified by the Office of the Interconnection in order to comply with the practical requirements and the economic and efficiency objectives of the scheduling process specified in this Schedule.

(a) Each Market Participant may submit to the Office of the Interconnection specifications of the amount and location of its customer loads and/or energy purchases to be included in the Day-ahead Energy Market for each hour of the next Operating Day, such specifications to comply with the requirements set forth in the PJM Manuals. Each Market Buyer shall inform the Office of the Interconnection of the prices, if any, at which it desires not to include its load in the Day-ahead Energy Market rather than pay the Day-ahead Price. PRD Providers that have committed Price Responsive Demand in accordance with the Reliability Assurance Agreement shall submit to the Office of the Interconnection, in accordance with procedures specified in the PJM Manuals, any desired updates to their previously submitted PRD Curves, provided that such updates are consistent with their Price Responsive Demand commitments, and provided further that PRD Providers that are not Load Serving Entities for the Price Responsive Demand at issue may only submit PRD Curves for the Real-time Energy Market. Price Responsive Demand that has been committed in accordance with the Reliability Assurance Agreement shall be presumed available for the next Operating Day in accordance with the most recently submitted PRD Curve unless the PRD Curve is updated to indicate otherwise. PRD Providers may also submit PRD Curves for any Price Responsive Demand that is not committed in accordance with the Reliability Assurance Agreement; provided that PRD Providers that are not Load Serving Entities for the Price Responsive Demand at issue may only submit PRD Curves for the Real-time Energy Market. All PRD Curves shall be on a PRD Substation basis, and shall specify the maximum time period required to implement load reductions.

(b) Each Generating Market Buyer shall submit to the Office of the Interconnection: (i) hourly schedules for resource increments, including hydropower units, self-scheduled by the Market Buyer to meet its Equivalent Load; and (ii) the Dispatch Rate at which each such self-scheduled resource will disconnect or reduce output, or confirmation of the Market Buyer's intent not to reduce output.

(c) All Market Participants shall submit to the Office of the Interconnection schedules for any energy exports, energy imports, and wheel through transactions involving use of generation or Transmission Facilities as specified below, and shall inform the Office of the Interconnection if the transaction is to be scheduled in the Day-ahead Energy Market. Any Market Participant that elects to schedule an export, import or wheel through transaction in the

Day-ahead Energy Market may specify the price (such price not to exceed the maximum price that may be specified in the PJM Manuals), if any, at which the export, import or wheel through transaction will be wholly or partially curtailed. The foregoing price specification shall apply to the applicable interface pricing point. Any Market Participant that elects not to schedule its export, import or wheel through transaction in the Day-ahead Energy Market shall inform the Office of the Interconnection if the parties to the transaction are not willing to incur Transmission Congestion and Loss Charges in the Real-time Energy Market in order to complete any such scheduled transaction. Scheduling of such transactions shall be conducted in accordance with the specifications in the PJM Manuals and the following requirements:

i) Market Participants shall submit schedules for all energy purchases for delivery within the PJM Region, whether from resources inside or outside the PJM Region;

ii) Market Participants shall submit schedules for exports for delivery outside the PJM Region from resources within the PJM Region that are not Dynamic Transfers to such entities pursuant to Section 1.12; and

iii) In addition to the foregoing schedules for exports, imports and wheel through transactions, Market Participants shall submit confirmations of each scheduled transaction from each other party to the transaction in addition to the party submitting the schedule, or the adjacent Control Area.

(c-1) A Market Participant may elect to submit in the Day-ahead Energy Market a form 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. The Office of Interconnection will schedule these transactions only to the extent this difference in Locational Marginal Prices is within the maximum amount specified by the Market Participant. A Virtual Transaction of this type is referred to as an "Up-to Congestion Transaction." Such Up-to Congestion Transactions may be wholly or partially scheduled depending on the price difference between the source and sink locations in the Day-ahead Energy Market. The maximum difference between the source and sink prices that a participant may specify shall be limited to +/- $50/MWh. The foregoing price specification shall apply to the price difference between the specified source and sink in the day-ahead scheduling process only. An accepted Up-to Congestion Transaction results in scheduled injection at a specified source and scheduled withdrawal of the same megawatt quantity at a specified sink in the Day-ahead Energy Market.

(c-2) Up-to Congestion Transactions may only be submitted at hubs, Residual Metered Load and interfaces not described in Tariff, Attachment K-Appendix, section 2.6A(b).
Increment Offers and Decrement Bids may be only submitted at hubs, nodes at which physical generation or load is settled, Residual Metered Load and interfaces not described in Tariff, Attachment K-Appendix, section 2.6A(b).

(d) Market Sellers in the Day-ahead Energy Market shall submit offers for the supply of energy, demand reductions, or other services for the following Operating Day for each clock

hour for which the Market Seller desires or is required to make its resource available to the Office of the Interconnection. Offers for the supply of energy may be cost-based, market-based, or both, and may vary hourly. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this Section 1.10.1A(d), Section 1.10.9B, Schedule 2 of the Operating Agreement, and the PJM Manuals, as applicable. Market Sellers owning or controlling the output of a Generation Capacity Resource that was committed in an FRR Capacity Plan, self-supplied, offered and cleared in a Base Residual Auction or Incremental Auction, or designated as replacement capacity, as specified in Attachment DD of the PJM Tariff, and that has not been rendered unavailable by a Generator Planned Outage, a Generator Maintenance Outage, or a Generator Forced Outage shall submit offers for the available capacity of such Generation Capacity Resource, including any portion that is self-scheduled by the Generating Market Buyer. Such offers shall be based on the ICAP equivalent of the Market Seller's cleared UCAP capacity commitment, provided, however, where the underlying resource is a Capacity Storage Resource or an Intermittent Resource, the Market Seller shall satisfy the must offer requirement by either self-scheduling or offering the unit as a dispatchable resource, in accordance with the PJM Manuals, where the hourly day-ahead self-scheduled values for such Capacity Storage Resources and Intermittent Resources may vary hour to hour from the capacity commitment. Any offer not designated as a Maximum Emergency offer shall be considered available for scheduling and dispatch under both Emergency and non-Emergency conditions. Offers may only be designated as Maximum Emergency offers to the extent that the Generation Capacity Resource falls into at least one of the following categories:

i) Environmental limits. If the resource has a limit on its run hours imposed by a federal, state, or other governmental agency that will significantly limit its availability, on either a temporary or long-term basis. This includes a resource that is limited to operating only during declared PJM capacity emergencies by a governmental authority.

ii) Fuel limits. If physical events beyond the control of the resource owner result in the temporary interruption of fuel supply and there is limited on-site fuel storage. A fuel supplier's exercise of a contractual right to interrupt supply or delivery under an interruptible service agreement shall not qualify as an event beyond the control of the resource owner.

iii) Temporary emergency conditions at the unit. If temporary emergency physical conditions at the resource significantly limit its availability.

iv) Temporary megawatt additions. If a resource can provide additional megawatts on a temporary basis by oil topping, boiler over-pressure, or similar techniques, and such megawatts are not ordinarily otherwise available.

The submission of offers for resource increments that have not cleared in a Base Residual Auction or an Incremental Auction, were not committed in an FRR Capacity Plan, and were not designated as replacement capacity under Attachment DD of the PJM Tariff shall be optional, but any such offers must contain the information specified in the Office of the Interconnection's

Offer Data specification, Operating Agreement Schedule 1, sections 1.10.1A(d) and 1.10.9B, Operating Agreement, Schedule 2 , and the PJM Manuals, as applicable. Energy offered from generation resources that have not cleared a Base Residual Auction or an Incremental Auction, were not committed in an FRR Capacity Plan, and were not designated as replacement capacity under Attachment DD of the PJM Tariff shall not be supplied from resources that are included in or otherwise committed to supply the Operating Reserves of a Control Area outside the PJM Region.

The foregoing offers:

i) Shall specify the Generation Capacity Resource or Demand Resource and energy or demand reduction amount, respectively, for each clock hour in the offer period;

ii) Shall specify the amounts and prices for each clock hour during the entire Operating Day for each resource component offered by the Market Seller to the Office of the Interconnection;

iii) May specify for generation resources offer parameters for each clock hour during the entire Operating Day, as applicable and in accordance with section 1.10.9B below, including: (1) Minimum Run Time; (2) maximum run time; (3) Start-up Costs; (4) No-load Costs; (5) Incremental Energy Offer; (6) notification time; (7) availability; (8) ramp rate; (9) Economic Minimum; (10) Economic Maximum; (11) emergency minimum MW; and (12) emergency maximum MW, and specify offer parameters for Demand Resources for each clock hour during the entire Operating Day, as applicable and in accordance with section 1.10.9B below, including: (1) minimum down time; (2) shutdown costs; (3) Incremental Energy Offer; (4) notification time; (5) Economic Minimum; and (6) Economic Maximum.;

iv) Shall set forth any special conditions upon which the Market Seller proposes to supply a resource increment, including any curtailment rate specified in a bilateral contract for the output of the resource, or any cancellation fees;

v) May include a schedule of offers for prices and operating data contingent on acceptance by the deadline specified in this Schedule, with additional schedules applicable if accepted after the foregoing deadline;

vi) Shall constitute an offer to submit the resource increment to the Office of the Interconnection for scheduling and dispatch in accordance with the terms of the offer for the clock hour, which offer shall remain open through the Operating Day, for which the offer is submitted, unless the Market Seller a) submits a Real-time Offer for the applicable clock hour, or b) updates the availability of its offer for that hour, as further described in the PJM Manuals;

vii) Shall be final as to the price or prices at which the Market Seller proposes to supply energy or other services to the PJM Interchange Energy Market, such price or prices being guaranteed by the Market Seller for the period extending through the end of

the following Operating Day, unless modified after the close of the Day-ahead Energy Market as permitted pursuant to sections 1.10.9A or 1.10.9B below;

viii) Shall not exceed an energy offer price of $1,000/megawatt-hour for all generation resources, except (1) when a Market Seller's cost-based offer is above $1,000/megawatt-hour and less than or equal to $2,000/megawatt-hour, then its market-based offer must be less than or equal to the cost-based offer; and (2) when a Market Seller's cost-based offer is greater than $2,000/megawatt-hour, then its market-based offer must be less than or equal to $2,000/megawatt-hour; and

ix) Shall not exceed a *demand reduction* offer price of $1,000/megawatt-hour*, except when an Economic Load Response Participant, an Emergency Load Response participant, or a Pre-Emergency Load Response participant submits a cost-based offer that includes an incremental cost component that is above $1,000/megawatt-hour, then its market-based offer must be less than or equal to the cost-based offer but in no event greater than $2,000/megawatt-hour; and*

x) Shall not exceed an energy offer price of $0.00/MWh for pumped storage hydropower units scheduled by the Office of the Interconnection pursuant to the hydro optimization tool in the Day-ahead Energy Market.

(e) A Market Seller that wishes to make a resource available to sell Regulation service shall submit an offer for Regulation for each clock hour for which the Market Seller desires to make its resource available to the Office of the Interconnection to provide Regulation that shall specify the megawatts of Regulation being offered, which must equal or exceed 0.1 megawatts, the Regulation Zone for which such Regulation is offered, the price of the capability offer in dollars per MW, the price of the performance offer in Dollars per change in MW, and such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer and the resource's opportunity costs. Such offers may vary hourly, and may be updated each hour, up to 65 minutes before the applicable clock hour during the Operating Day. The total of the performance offer multiplied by the historical average mileage used in the market clearing plus the capability offer shall not exceed $100/megawatt-hour in the case of Regulation offered for all Regulation Zones. In addition to any market-based offer for Regulation, the Market Seller also shall submit a cost-based offer. A cost-based offer must be in the form specified in the PJM Manuals and consist of the following components as well as any other components specified in the PJM Manuals:

i. The costs (in $/MW) of the fuel cost increase due to the steady-state heat rate increase resulting from operating the unit at lower megawatt output incurred from the provision of Regulation shall apply to the capability offer;

ii. The cost increase (in $/ΔMW) in costs associated with movement of the regulation resource incurred from the provision of Regulation shall apply to the performance offer; and

iii. An adder of up to $12.00 per megawatt of Regulation provided applied to the capability offer.

Qualified Regulation capability must satisfy the measurement and verification tests specified in the PJM Manuals.

(f) Each Market Seller owning or controlling the output of a Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative shall submit a forecast of the availability of each such Generation Capacity Resource for the next seven days. A Market Seller (i) may submit a non-binding forecast of the price at which it expects to offer a generation resource increment to the Office of the Interconnection over the next seven days, and (ii) shall submit a binding offer for energy, along with Start-up Costs and No-load Costs, if any, for the next seven days or part thereof, for any generation resource with minimum notification or start-up requirement greater than 24 hours. Such resources committed by the Office of the Interconnection will not receive Operating Reserve Credits nor otherwise be made whole for its hours of operation for the duration of any portion of such commitment that exceeds the maximum start-up and notification times for such resources during Hot Weather Alerts and Cold Weather Alerts, consistent with Sections 3.2.3 and 6.6 hereof.

(g) Each component of an offer by a Market Seller of a Generation Capacity Resource that is constant for the entire Operating Day and does not vary hour to hour shall remain in effect for subsequent Operating Days until superseded or canceled.

(h) The Office of the Interconnection shall post the total hourly loads scheduled in the Day-ahead Energy Market, as well as, its estimate of the combined hourly load of the Market Buyers for the next four days, and peak load forecasts for an additional three days.

(i) Except for Economic Load Response Participants, all Market Participants may submit Virtual Transactions that apply to the Day-ahead Energy Market only. Such Virtual Transactions must comply with the requirements set forth in the PJM Manuals and must specify amount, location and price, if any, at which the Market Participant desires to purchase or sell energy in the Day-ahead Energy Market. The Office of the Interconnection may require that a market participant shall not submit in excess of a defined number of bid/offer segments in the Day-ahead Energy Market, as specified in the PJM Manuals, when the Office of the Interconnection determines that such limit is required to avoid or mitigate significant system performance problems related to bid/offer volume. Notice of the need to impose such limit shall be provided prior to 10:00 a.m. EPT on the day that the Day-ahead Energy Market will clear. For purposes of this provision, a bid/offer segment is each pairing of price and megawatt quantity submitted as part of an Increment Offer or Decrement Bid. For purposes of applying this provision to an Up-to Congestion Transaction, a bid/offer segment shall refer to the pairing of a source and sink designation, as well as price and megawatt quantity, that comprise each Up-to Congestion Transaction.

(j) A Market Seller that wishes to make a generation resource or Demand Resource available to sell Synchronized Reserve shall submit an offer for Synchronized Reserve for each

clock hour for which the Market Seller desires or is required to make its resource available to the Office of the Interconnection to provide Synchronized Reserve that shall specify the megawatts of Synchronized Reserve being offered, which must equal or exceed 0.1 megawatts, the price of the offer in dollars per megawatt hour, and such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer and the energy used by the generation resource to provide the Synchronized Reserve and the generation resource's unit specific opportunity costs. Such offers may vary hourly, and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day. The price of the offer shall not exceed the variable operating and maintenance costs for providing Synchronized Reserve plus seven dollars and fifty cents.

(k) An Economic Load Response Participant that wishes to participate in the Day-ahead Energy Market by reducing demand shall submit an offer to reduce demand to the Office of the Interconnection for each clock hour for which the Economic Load Response Participant desires to make its resource available to the Office of the Interconnection to reduce demand. The offer must equal or exceed 0.1 megawatts, may vary hourly, and shall specify: (i) the amount of the offered curtailment in minimum increments of .1 megawatts: (ii) the Day-ahead Locational Marginal Price above which the end-use customer will reduce load, subject to section 1.10.1A(d)(ix); and (iii) at the Economic Load Response Participant's option, start-up costs associated with reducing load, including direct labor and equipment costs, opportunity costs, and/or a minimum of number of contiguous hours for which the load reduction must be committed. Such offers may be updated each hour, up to 65 minutes before the applicable clock hour during the Operating Day. Economic Load Response Participants submitting offers to reduce demand in the Day-ahead Energy Market may establish an incremental offer curve, provided that such offer curve shall be limited to ten price pairs (in MWs) per hour.

(l) Market Sellers owning or controlling the output of a Demand Resource that was committed in an FRR Capacity Plan, or that was self-supplied or that offered and cleared in a Base Residual Auction or Incremental Auction, may submit demand reduction bids for the available load reduction capability of the Demand Resource. The submission of demand reduction bids for Demand Resource increments that were not committed in an FRR Capacity Plan, or that have not cleared in a Base Residual Auction or Incremental Auction, shall be optional, but any such bids must contain the information required to be included in such bids, as specified in the PJM Economic Load Response Program. A Demand Resource that was committed in an FRR Capacity Plan, or that was self-supplied or offered and cleared in a Base Residual Auction or Incremental Auction, may submit a demand reduction bid in the Day-ahead Energy Market as specified in the Economic Load Response Program; provided, however, that in the event of an Emergency PJM shall require Demand Resources to reduce load, notwithstanding that the Zonal LMP at the time such Emergency is declared is below the price identified in the demand reduction bid.

(m) Market Sellers providing Day-ahead Scheduling Reserves Resources shall submit in the Day-ahead Scheduling Reserves Market: 1) a price offer in dollars per megawatt hour; and 2) such other information specified by the Office of the Interconnection as may be necessary to determine any relevant opportunity costs for the resource(s). The foregoing notwithstanding, to qualify to submit Day-ahead Scheduling Reserves pursuant to this section, the Day-ahead

Scheduling Reserves Resources shall submit energy offers in the Day-ahead Energy Market including start-up and shut-down costs for generation resource and Demand Resources, respectively, and all generation resources that are capable of providing Day-ahead Scheduling Reserves that a particular resource can provide that service. The megawatt quantity of Day-ahead Scheduling Reserves that a particular resource can provide in a given hour will be determined based on the energy Offer Data submitted in the Day-ahead Energy Market, as detailed in the PJM Manuals.

1.10.1B Demand Bid Scheduling and Screening

(a) The Office of the Interconnection shall apply Demand Bid Screening to all Demand Bids submitted in the Day-ahead Energy Market for each Load Serving Entity, separately by Zone. Using Demand Bid Screening, the Office of the Interconnection will automatically reject a Load Serving Entity's Demand Bids in any future Operating Day for which the Load Serving Entity submits bids if the total megawatt volume of such bids would exceed the Load Serving Entity's Demand Bid Limit for any hour in such Operating Day, unless the Office of the Interconnection permits an exception pursuant to subsection (d) below.

(b) On a daily basis, PJM will update and post each Load Serving Entity's Demand Bid Limit in each applicable Zone. Such Demand Bid Limit will apply to all Demand Bids submitted by that Load Serving Entity for each future Operating Day for which it submits bids. The Demand Bid Limit is calculated using the following equation:

Demand Bid Limit = greater of (Zonal Peak Demand Reference Point * 1.3), or (Zonal Peak Demand Reference Point + 10MW)

Where:

1. Zonal Peak Demand Reference Point = for each Zone: the product of (a) LSE Recent Load Share, multiplied by (b) Peak Daily Load Forecast.
2. LSE Recent Load Share is the Load Serving Entity's highest share of Network Load in each Zone for any hour over the most recently available seven Operating Days for which PJM has data.
3. Peak Daily Load Forecast is PJM's highest available peak load forecast for each applicable Zone that is calculated on a daily basis.

(c) A Load Serving Entity whose Demand Bids are rejected as a result of Demand Bid Screening may change its Demand Bids to reduce its total megawatt volume to a level that does not exceed its Demand Bid Limit, and may resubmit them subject to the applicable rules related to bid submission outlined in Tariff, Operating Agreement and PJM Manuals.

(d) PJM may allow a Load Serving Entity to submit bids in excess of its Demand Bid Limit when circumstances exist that will cause, or are reasonably expected to cause, a Load Serving Entity's actual load to exceed its Demand Bid Limit on a given Operating Day. Examples of such circumstances include, but are not limited to, changes in load commitments due to state sponsored auctions, mergers and acquisitions between PJM Members, and sales and divestitures between PJM Members. A Load Serving Entity may submit a written exception

request to the Office of Interconnection for a higher Demand Bid Limit for an affected Operating Day. Such request must include a detailed explanation of the circumstances at issue and supporting documentation that justify the Load Serving Entity's expectation that its actual load will exceed its Demand Bid Limit.

1.10.2 Pool-scheduled Resources.

Pool-scheduled resources are those resources for which Market Participants submitted offers to sell energy in the Day-ahead Energy Market and offers to reduce demand in the Day-ahead Energy Market, which the Office of the Interconnection scheduled in the Day-ahead Energy Market as well as generators committed by the Office of the Interconnection subsequent to the Day-ahead Energy Market. Such resources shall be committed to provide energy in the real-time dispatch unless the schedules for such units are revised pursuant to Sections 1.10.9 or 1.11. Pool-scheduled resources shall be governed by the following principles and procedures.

(a) Pool-scheduled resources shall be selected by the Office of the Interconnection on the basis of the prices offered for energy and demand reductions and related services, whether the resource is expected to be needed to maintain system reliability during the Operating Day, Start-up Costs, No-load Costs and cancellation fees, and the specified operating characteristics, offered by Market Sellers to the Office of the Interconnection by the offer deadline specified in Section 1.10.1A. Hydropower units can only be pool-scheduled if they are pumped storage units and scheduled by the Office of the Interconnection pursuant to the hydro optimization tool in the Day-ahead Energy Market.

(b) A resource that is scheduled by a Market Participant to support a bilateral sale, or that is self-scheduled by a Generating Market Buyer, shall not be selected by the Office of the Interconnection as a pool-scheduled resource except in an Emergency.

(c) Market Sellers offering energy from hydropower or other facilities with fuel or environmental limitations may submit data to the Office of the Interconnection that is sufficient to enable the Office of the Interconnection to determine the available operating hours of such facilities.

(d) The Market Seller of a resource selected as a pool-scheduled resource shall receive payments or credits for energy, demand reductions or related services, or for Start-up Costs and No-load Costs, from the Office of the Interconnection on behalf of the Market Buyers in accordance with Section 3 of this Schedule 1. Alternatively, the Market Seller shall receive, in lieu of Start-up Costs and No-load Costs, its actual costs incurred, if any, up to a cap of the resource's Start-up Costs, if the Office of the Interconnection cancels its selection of the resource as a pool-scheduled resource and so notifies the Market Seller before the resource is synchronized.

(e) Market Participants shall make available their pool-scheduled resources to the Office of the Interconnection for coordinated operation to supply the Operating Reserves needs of the applicable Control Zone.

(f) Economic Load Response Participants offering to reduce demand shall specify: (i) the amount of the offered curtailment, which offer must equal or exceed 0.1 megawatts, in minimum increments of .1 megawatts; (ii) the real-time Locational Marginal Price above which the end-use customer will reduce load; and (iii) at the Economic Load Response Participant's option, shut-down costs associated with reducing load, including direct labor and equipment costs, opportunity costs, and/or a minimum number of contiguous hours for which the load reduction must be committed. Economic Load Response Participants submitting offers to reduce demand in the Real-time Energy Market may establish an incremental offer curve, provided that such offer curve shall be limited to ten price pairs (in MWs). Economic Load Response Participants offering to reduce demand shall also indicate the hours that the demand reduction is not available.

1.10.3 Self-scheduled Resources.

Self-scheduled resources shall be governed by the following principles and procedures.

(a) Each Generating Market Buyer shall use all reasonable efforts, consistent with Good Utility Practice, not to self-schedule resources in excess of its Equivalent Load.

(b) The offered prices of resources that are self-scheduled, or otherwise not following the dispatch orders of the Office of the Interconnection, shall not be considered by the Office of the Interconnection in determining Locational Marginal Prices.

(c) Market Participants shall make available their self-scheduled resources to the Office of the Interconnection for coordinated operation to supply the Operating Reserves needs of the applicable Control Zone, by submitting an offer as to such resources.

(d) A Market Participant self-scheduling a resource in the Day-ahead Energy Market that does not deliver the energy in the Real-time Energy Market, shall replace the energy not delivered with energy from the Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

(e) Hydropower units, excluding pumped storage units, may only be self-scheduled.

1.10.4 Capacity Resources.

(a) A Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative that is selected as a pool-scheduled resource shall be made available for scheduling and dispatch at the direction of the Office of the Interconnection. Such a Generation Capacity Resource that does not deliver energy as scheduled shall be deemed to have experienced a Generator Forced Outage to the extent of such energy not delivered. A Market Participant offering such Generation Capacity Resource in the Day-ahead Energy Market shall replace the energy not delivered with energy from the Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

(b) Energy from a Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative that has not been scheduled in the Day-ahead Energy Market may be sold on a bilateral basis by the Market Seller, may be self-scheduled, or may be offered for dispatch during the Operating Day in accordance with the procedures specified in this Schedule. Such a Generation Capacity Resource that has not been scheduled in the Day-ahead Energy Market and that has been sold on a bilateral basis must be made available upon request to the Office of the Interconnection for scheduling and dispatch during the Operating Day if the Office of the Interconnection declares a Maximum Generation Emergency. Any such resource so scheduled and dispatched shall receive the applicable Real-time Price for energy delivered.

(c) A resource that has been self-scheduled shall not receive payments or credits for Start-up Costs or No-load Costs.

1.10.5 External Resources.

(a) External Resources may submit offers to the PJM Interchange Energy Market, in accordance with the day-ahead and real-time scheduling processes specified above. An External Resource selected as a pool-scheduled resource shall be made available for scheduling and dispatch at the direction of the Office of the Interconnection, and except as specified below shall be compensated on the same basis as other pool-scheduled resources. External Resources that are not capable of Dynamic Transfer shall, if selected by the Office of the Interconnection on the basis of the Market Seller's Offer Data, be block loaded on an hourly scheduled basis. Market Sellers shall offer External Resources to the PJM Interchange Energy Market on either a resource-specific or an aggregated resource basis. A Market Participant whose pool-scheduled resource does not deliver the energy scheduled in the Day-ahead Energy Market shall replace such energy not delivered as scheduled in the Day-ahead Energy Market with energy from the PJM Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

(b) Offers for External Resources from an aggregation of two or more generating units shall so indicate, and shall specify, in accordance with the Offer Data requirements specified by the Office of the Interconnection: (i) energy prices; (ii) hours of energy availability; (iii) a minimum dispatch level; (iv) a maximum dispatch level; and (v) unless such information has previously been made available to the Office of the Interconnection, sufficient information, as specified in the PJM Manuals, to enable the Office of the Interconnection to model the flow into the PJM Region of any energy from the External Resources scheduled in accordance with the Offer Data.

(c) Offers for External Resources on a resource-specific basis shall specify the resource being offered, along with the information specified in the Offer Data as applicable.

1.10.6 External Market Buyers.

(a) Deliveries to an External Market Buyer not subject to Dynamic Transfer by the Office of the Interconnection shall be delivered on a block loaded basis to the bus or buses at the electrical boundaries of the PJM Region, or in such area with respect to an External Market

Buyer's load within such area not served by Network Service, at which the energy is delivered to or for the External Market Buyer. External Market Buyers shall be charged (which charge may be positive or negative) at either the Day-ahead Prices or Real-time Prices, whichever is applicable, for energy at the foregoing bus or buses.

(b) An External Market Buyer's hourly schedules for energy purchased from the PJM Interchange Energy Market shall conform to the ramping and other applicable requirements of the interconnection agreement between the PJM Region and the Control Area to which, whether as an intermediate or final point of delivery, the purchased energy will initially be delivered.

(c) The Office of the Interconnection shall curtail deliveries to an External Market Buyer if necessary to maintain appropriate reserve levels for a Control Zone as defined in the PJM Manuals, or to avoid shedding load in such Control Zone.

1.10.6A Transmission Loading Relief Customers.

(a) An entity that desires to elect to pay Transmission Congestion Charges in order to continue its energy schedules during an Operating Day over contract paths outside the PJM Region in the event that PJM initiates Transmission Loading Relief that otherwise would cause PJM to request security coordinators to curtail such Member's energy schedules shall:

(i) enter its election on OASIS by 10:30 a.m. of the day before the Operating Day, in accordance with procedures established by PJM, which election shall be applicable for the entire Operating Day; and

(ii) if PJM initiates Transmission Loading Relief, provide to PJM, at such time and in accordance with procedures established by PJM, the hourly integrated energy schedules that impacted the PJM Region (as indicated from the NERC Interchange Distribution Calculator) during the Transmission Loading Relief.

(b) If an entity has made the election specified in Section (a), then PJM shall not request security coordinators to curtail such entity's energy transactions, except as may be necessary to respond to Emergencies.

(c) In order to make elections under this Section 1.10.6A, an entity must (i) have met the creditworthiness standards established by the Office of the Interconnection or provided a letter of credit or other form of security acceptable to the Office of the Interconnection, and (ii) have executed either the Agreement, a Service Agreement under the PJM Tariff, or other agreement committing to pay all Transmission Congestion Charges incurred under this Section.

1.10.7 Bilateral Transactions.

Bilateral transactions as to which the parties have notified the Office of the Interconnection by the deadline specified in Section 1.10.1A that they elect not to be included in the Day-ahead Energy Market and that they are not willing to incur Transmission Congestion Charges in the Real-time Energy Market shall be curtailed by the Office of the Interconnection as necessary to

reduce or alleviate transmission congestion. Bilateral transactions that were not included in the Day-ahead Energy Market and that are willing to incur congestion charges and bilateral transactions that were accepted in the Day-ahead Energy Market shall continue to be implemented during periods of congestion, except as may be necessary to respond to Emergencies.

1.10.8 Office of the Interconnection Responsibilities.

(a) The Office of the Interconnection shall use its best efforts to determine (i) the least-cost means of satisfying the projected hourly requirements for energy, Operating Reserves, and other ancillary services of the Market Buyers, including the reliability requirements of the PJM Region, of the Day-ahead Energy Market, and (ii) the least-cost means of satisfying the Operating Reserve and other ancillary service requirements for any portion of the load forecast of the Office of the Interconnection for the Operating Day in excess of that scheduled in the Day-ahead Energy Market. In making these determinations, the Office of the Interconnection shall take into account: (i) the Office of the Interconnection's forecasts of PJM Interchange Energy Market and PJM Region energy requirements, giving due consideration to the energy requirement forecasts and purchase requests submitted by Market Buyers and PRD Curves properly submitted by Load Serving Entities for the Price Responsive Demand loads they serve; (ii) the offers submitted by Market Sellers; (iii) the availability of limited energy resources; (iv) the capacity, location, and other relevant characteristics of self-scheduled resources; (v) the objectives of each Control Zone for Operating Reserves, as specified in the PJM Manuals; (vi) the requirements of each Regulation Zone for Regulation and other ancillary services, as specified in the PJM Manuals; (vii) the benefits of avoiding or minimizing transmission constraint control operations, as specified in the PJM Manuals; and (viii) such other factors as the Office of the Interconnection reasonably concludes are relevant to the foregoing determination, including, without limitation, transmission constraints on external coordinated flowgates to the extent provided by section 1.7.6. The Office of the Interconnection shall develop a Day-ahead Energy Market based on the foregoing determination, and shall determine the Day-ahead Prices resulting from such schedule. The Office of the Interconnection shall report the planned schedule for a hydropower resource to the operator of that resource as necessary for plant safety and security, and legal limitations on pond elevations.

(b) By 1:30 p.m., or as soon as practicable thereafter, of the day before each Operating Day, or such other deadline as may be specified by the Office of the Interconnection in the PJM Manuals, the Office of the Interconnection shall: (i) post the aggregate Day-ahead Energy Market results; (ii) post the Day-ahead Prices; and (iii) inform the Market Sellers, Market Buyers, and Economic Load Response Participants of their scheduled injections, withdrawals, and demand reductions respectively. The foregoing notwithstanding, the deadlines set forth in this subsection shall not apply if the Office of the Interconnection is unable to obtain Market Participant bid/offer data due to extraordinary circumstances. For purposes of this subsection, extraordinary circumstances shall mean a technical malfunction that limits, prohibits or otherwise interferes with the ability of the Office of the Interconnection to obtain Market Participant bid/offer data prior to 11:59 p.m. on the day before the affected Operating Day. Extraordinary circumstances do not include a Market Participant's inability to submit bid/offer data to the Office of the Interconnection. If the Office of the Interconnection is unable to clear

the Day-ahead Energy Market prior to 11:59 p.m. on the day before the affected Operating Day as a result of such extraordinary circumstances, the Office of the Interconnection shall notify Members as soon as practicable.

(c) Following posting of the information specified in Section 1.10.8(b), and absent extraordinary circumstances preventing the clearing of the Day-ahead Energy Market, the Office of the Interconnection shall revise its schedule of generation resources to reflect updated projections of load, conditions affecting electric system operations in the PJM Region, the availability of and constraints on limited energy and other resources, transmission constraints, and other relevant factors.

(d) Market Buyers shall pay PJMSettlement and Market Sellers shall be paid by PJMSettlement for the quantities of energy scheduled in the Day-ahead Energy Market at the Day-ahead Prices when the Day-ahead Price is positive. Market Buyers shall be paid by PJMSettlement and Market Sellers shall pay PJMSettlement for the quantities of energy scheduled in the Day-ahead Energy Market at the Day-ahead Prices when the Day-ahead Price is negative. Economic Load Response Participants shall be paid for scheduled demand reductions pursuant to Section 3.3A of this Schedule. Notwithstanding the foregoing, if the Office of the Interconnection is unable to clear the Day-ahead Energy Market prior to 11:59 p.m. on the day before the affected Operating Day due to extraordinary circumstances as described in subsection (b) above, no settlements shall be made for the Day-ahead Energy Market, no scheduled megawatt quantities shall be established, and no Day-ahead Prices shall be established for that Operating Day. Rather, for purposes of settlements for such Operating Day, the Office of the Interconnection shall utilize a scheduled megawatt quantity and price of zero and all settlements, including Financial Transmission Right Target Allocations, will be based on the real-time quantities and prices as determined pursuant to Sections 2.4 and 2.5 hereof.

(e) If the Office of the Interconnection discovers an error in prices and/or cleared quantities in the Day-ahead Energy Market, Real-time Energy Market, Ancillary Services Markets or Day Ahead Scheduling Reserve Market after it has posted the results for these markets on its Web site, the Office of the Interconnection shall notify Market Participants of the error as soon as possible after it is found, but in no event later than 12:00 p.m. of the second Business Day following the Operating Day for the Ancillary Services Markets and Real-time Energy Market, and no later than 5:00 p.m. of the second Business Day following the initial publication of the results for the Day-ahead Scheduling Reserve Market and Day-ahead Energy Market.

After this initial notification, if the Office of the Interconnection determines it is necessary to post modified results, it shall provide notification of its intent to do so, together with all available supporting documentation, by no later than 5:00 p.m. of the fifth Business Day following the Operating Day for the Ancillary Services Markets and Real-time Energy Market, and no later than 5:00 p.m. of the fifth Business Day following the initial publication of the results in the Day-ahead Scheduling Reserve Market and the Day-ahead Energy Market. Thereafter, the Office of the Interconnection must post on its Web site the corrected results by no later than 5:00 p.m. of the tenth calendar day following the Operating Day for the Ancillary Services Markets, Day-ahead Energy Market and Real-time Energy Market, and no later than 5:00 p.m. of the tenth

calendar day following the initial publication of the results in the Day-ahead Scheduling Reserve Market. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced market results are under publicly noticed review by the FERC.

(f) Consistent with Section 18.17.1 of the PJM Operating Agreement, and notwithstanding anything to the contrary in the Operating Agreement or in the PJM Tariff, to allow the tracking of Market Participants' non-aggregated bids and offers over time as required by FERC Order No. 719, the Office of the Interconnection shall post on its Web site the non-aggregated bid data and Offer Data submitted by Market Participants (for participation in the PJM Interchange Energy Market) approximately four months after the bid or offer was submitted to the Office of the Interconnection.

1.10.9 Hourly Scheduling.

(a) Following the initial posting by the Office of the Interconnection of the Locational Marginal Prices resulting from the Day-ahead Energy Market, and subject to the right of the Office of the Interconnection to schedule and dispatch pool-scheduled resources and to direct that schedules be changed in an Emergency, and absent extraordinary circumstances preventing the clearing of the Day-ahead Energy Market, a generation rebidding period shall exist. Typically the rebidding period shall be from the time the Office of the Interconnection posts the results of the Day-ahead Energy Market until 2:15 p.m. on the day before each Operating Day. However, should the clearing of the Day-ahead Energy Market be significantly delayed, the Office of the Interconnection may establish a revised rebidding period. During the rebidding period, Market Participants may submit revisions to generation Offer Data for the next Operating Day. Adjustments to the Day-ahead Energy Market shall be settled at the applicable Real-time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-ahead Energy Market at the applicable Day-ahead Prices.

(b) A Market Participant may adjust the schedule of a resource under its dispatch control on an hour-to-hour basis beginning at 10:00 p.m. of the day before each Operating Day, provided that the Office of the Interconnection is notified not later than 65 minutes prior to the hour in which the adjustment is to take effect, as follows and as specified in section 1.10.9A of this Schedule:

i) A Generating Market Buyer may self-schedule any of its resource increments, including hydropower resources, not previously designated as self-scheduled and not selected as a pool-scheduled resource in the Day-ahead Energy Market;

ii) A Market Participant may request the scheduling of a non-firm bilateral transaction; or

iii) A Market Participant may request the scheduling of deliveries or receipts of Spot Market Energy; or

iv) A Generating Market Buyer may remove from service a resource increment, including a hydropower resource, that it had previously designated as self-scheduled, provided that the Office of the Interconnection shall have the option to schedule energy from any such resource increment that is a Capacity Resource at the price offered in the scheduling process, with no obligation to pay any Start-Up Costs.

(c) An External Market Buyer may refuse delivery of some or all of the energy it requested to purchase in the Day-ahead Energy Market by notifying the Office of the Interconnection of the adjustment in deliveries not later than 65 minutes prior to the hour in which the adjustment is to take effect, but any such adjustment shall not affect the obligation of the External Market Buyer to pay for energy scheduled on its behalf in the Day-ahead Energy Market at the applicable Day-ahead Prices.

(d) The Office of the Interconnection shall provide External Market Buyers and External Market Sellers and parties to bilateral transactions with any revisions to their schedules resulting from the rebidding period by 6:30 p.m. on the day before each Operating Day. The Office of the Interconnection may also commit additional resources after such time as system conditions require. For each hour in the Operating Day, as soon as practicable after the deadlines specified in the foregoing subsection of this Section 1.10, the Office of the Interconnection shall provide External Market Buyers and External Market Sellers and parties to bilateral transactions with any revisions to their schedules for the hour.

1.10.9A Updating Offers in Real-time

(a) Each Market Seller may submit Real-time Offers for a resource up to 65 minutes before the applicable clock hour, and such Real-time Offers shall supersede any previous offer for that resource for the clock hour, as further described in the PJM Manuals and subject to the following conditions:

(*i*) A market-based Real-time Offer shall not exceed the applicable energy offer caps specified in this Schedule. Once a Market Seller's resource is committed for an applicable clock hour, the Market Seller may not increase its Incremental Energy Offer and may only submit a market-based Real-time Offer that is higher than its market-based offer that was in effect at the time of commitment to reflect increases in the resource's cost-based Start-up Costs and cost-based No-load Costs. The Market Seller may elect not to have its market-based offer considered for dispatch and to have only its lowest cost-based offer considered for the remainder of the Operating Day.

(*ii*) Cost-based Real-time Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection's Offer Data specification, Operating Agreement, Schedule 1, sections 1.10.1A(d) and 1.10.9B, Operating Agreement, Schedule 2 and the PJM Manuals, as applicable. If a Market Seller submits a market-based Real-time Offer for a particular clock hour in accordance

with subsection (c) below, or if updates to a cost-based offer are required by the Market Seller's approved Fuel Cost Policy, the Market Seller shall update its previously submitted cost-based Real-time Offer.

(*iii*) If a Market Seller's available cost-based offer is not compliant with Operating Agreement, Schedule 2 and the PJM Manuals at the time a Market Seller submits a market-based Real-time Offer for an applicable clock hour during the Operating Day, the Market Seller must submit an updated cost-based Real-time Offer consisting of an Incremental Energy Offer, Start-up Cost and No-load Cost for that clock hour that is compliant with Operating Agreement, Schedule 2 and the PJM Manuals.

(b) Each Market Seller may submit Real-time Offers for a resource during and through the end of the applicable clock hour to update only the following offer parameters, as further described in the PJM Manuals: (1) Economic Minimum; (2) Economic Maximum; (3) emergency minimum MW; (4) emergency maximum MW; (5) unit availability status; and (6) fixed output indicator. Such Real-time Offers shall supersede any previous offer for that resource for the clock hour.

1.10.9B Offer Parameter Flexibility

(a) Market Sellers may, in accordance with sections 1.10.1A and 1.10.9A above, this section 1.10.9B, and the PJM Manuals, update offer parameters at any time up to 65 minutes before the applicable clock hour, including prior to the close of the Day-ahead Energy Market and prior to the close of the rebidding period specified in section 1.10.9, except that Market Sellers may not update their offers for the supply of energy or demand reduction: (1) during the period after the close the Day-ahead Energy Market and prior to the posting of the Day-ahead Energy Market results pursuant to section 1.10.8(b); or (2) during the period after close of the rebidding period and prior to PJM announcing the results of the rebidding period pursuant to section 1.10.9(d).

(b) For generation resource offers, Market Sellers may vary for each clock hour during the entire Operating Day the following offer parameters: (1) cost-based Start-up Costs; (2) cost-based No-load Costs; (3) Incremental Energy Offer; (4) Economic Minimum and Economic Maximum; (5) emergency minimum MW and emergency maximum MW; and (6) for Real-time Offers only, *(i)* notification time and *(ii) for uncommitted hours only*, Minimum Run Time.

(c) For Demand Resource offers, Market Sellers may vary for each clock hour during the entire Operating Day the following offer parameters: (1) shutdown costs, (2) Incremental

Energy Offer; (3) Economic Minimum; (4) Economic Maximum; and (5) for Real-time Offers only, *(i)* notification time and *(ii) for uncommitted hours only,* minimum down time.

(d) After the announcement of the results of the rebidding period pursuant to section 1.10.9(d), *a* Market Seller may submit a Real-time Offer where offer parameters *may differ from the offer originally submitted in the Day-ahead Energy Market, except that a Market Seller may not submit a Real-time Offer that changes, of the offer parameters listed in section 1.10.1A(d), the* MW amounts specified in the Incremental Energy Offer, *ramp rate, maximum run time,* and availability*; provided, however, Market Sellers of dual-fueled resources may submit Real-time Offers for such resources that change the availability of a submitted cost-based offer.*

Section(s) of the
PJM Operating Agreement

(Clean Format)

1.10 Scheduling.

1.10.1 General.

(a) The Office of the Interconnection shall administer scheduling processes to implement a Day-ahead Energy Market and a Real-time Energy Market. PJMSettlement shall be the Counterparty to the purchases and sales of energy that clear the Day-ahead Energy Market and the Real-time Energy Market; provided that PJMSettlement shall not be a contracting party to bilateral transactions between Market Participants or with respect to a Generating Market Buyer's self-schedule or self-supply of its generation resources up to that Generating Market Buyer's Equivalent Load.

(b) The Day-ahead Energy Market shall enable Market Participants to purchase and sell energy through the PJM Interchange Energy Market at Day-ahead Prices and enable Transmission Customers to reserve transmission service with Transmission Congestion Charges and Transmission Loss Charges based on locational differences in Day-ahead Prices. Up-to Congestion Transactions submitted in the Day-ahead Energy Market shall not require transmission service and Transmission Customers shall not reserve transmission service for such Up-to Congestion Transactions. Market Participants whose purchases and sales, and Transmission Customers whose transmission uses are scheduled in the Day-ahead Energy Market, shall be obligated to purchase or sell energy, or pay Transmission Congestion Charges and Transmission Loss Charges, at the applicable Day-ahead Prices for the amounts scheduled.

(c) In the Real-time Energy Market, Market Participants that deviate from the amounts of energy purchases or sales, or Transmission Customers that deviate from the transmission uses, scheduled in the Day-ahead Energy Market shall be obligated to purchase or sell energy, or pay Transmission Congestion Charges and Transmission Loss Charges, for the amount of the deviations at the applicable Real-time Prices or price differences, unless otherwise specified by this Schedule.

(d) The following scheduling procedures and principles shall govern the commitment of resources to the Day-ahead Energy Market and the Real-time Energy Market over a period extending from one week to one hour prior to the real-time dispatch. Scheduling encompasses the day-ahead and hourly scheduling process, through which the Office of the Interconnection determines the Day-ahead Energy Market and determines, based on changing forecasts of conditions and actions by Market Participants and system constraints, a plan to serve the hourly energy and reserve requirements of the Internal Market Buyers and the purchase requests of the External Market Buyers in the least costly manner, subject to maintaining the reliability of the PJM Region. Scheduling does not encompass Coordinated External Transactions, which are subject to the procedures of Section 1.13 of this Schedule 1 of this Agreement. Scheduling shall be conducted as specified in Section 1.10.1A below, subject to the following condition. If the Office of the Interconnection's forecast for the next seven days projects a likelihood of Emergency conditions, the Office of the Interconnection may commit, for all or part of such seven day period, to the use of generation resources with notification or start-up times greater than one day as necessary in order to alleviate or mitigate such Emergency, in accordance with the Market Sellers' offers for such units for such periods and the specifications in the PJM

Manuals. Such resources committed by the Office of the Interconnection to alleviate or mitigate an Emergency will not receive Operating Reserve Credits nor otherwise be made whole for its hours of operation for the duration of any portion of such commitment that exceeds the maximum start-up and notification times for such resources during Hot Weather Alerts and Cold Weather Alerts, consistent with Sections 3.2.3 and 6.6 hereof.

1.10.1A Day-ahead Energy Market Scheduling.

The following actions shall occur not later than 10:30 a.m. on the day before the Operating Day for which transactions are being scheduled, or such other deadline as may be specified by the Office of the Interconnection in order to comply with the practical requirements and the economic and efficiency objectives of the scheduling process specified in this Schedule.

(a) Each Market Participant may submit to the Office of the Interconnection specifications of the amount and location of its customer loads and/or energy purchases to be included in the Day-ahead Energy Market for each hour of the next Operating Day, such specifications to comply with the requirements set forth in the PJM Manuals. Each Market Buyer shall inform the Office of the Interconnection of the prices, if any, at which it desires not to include its load in the Day-ahead Energy Market rather than pay the Day-ahead Price. PRD Providers that have committed Price Responsive Demand in accordance with the Reliability Assurance Agreement shall submit to the Office of the Interconnection, in accordance with procedures specified in the PJM Manuals, any desired updates to their previously submitted PRD Curves, provided that such updates are consistent with their Price Responsive Demand commitments, and provided further that PRD Providers that are not Load Serving Entities for the Price Responsive Demand at issue may only submit PRD Curves for the Real-time Energy Market. Price Responsive Demand that has been committed in accordance with the Reliability Assurance Agreement shall be presumed available for the next Operating Day in accordance with the most recently submitted PRD Curve unless the PRD Curve is updated to indicate otherwise. PRD Providers may also submit PRD Curves for any Price Responsive Demand that is not committed in accordance with the Reliability Assurance Agreement; provided that PRD Providers that are not Load Serving Entities for the Price Responsive Demand at issue may only submit PRD Curves for the Real-time Energy Market. All PRD Curves shall be on a PRD Substation basis, and shall specify the maximum time period required to implement load reductions.

(b) Each Generating Market Buyer shall submit to the Office of the Interconnection: (i) hourly schedules for resource increments, including hydropower units, self-scheduled by the Market Buyer to meet its Equivalent Load; and (ii) the Dispatch Rate at which each such self-scheduled resource will disconnect or reduce output, or confirmation of the Market Buyer's intent not to reduce output.

(c) All Market Participants shall submit to the Office of the Interconnection schedules for any energy exports, energy imports, and wheel through transactions involving use of generation or Transmission Facilities as specified below, and shall inform the Office of the Interconnection if the transaction is to be scheduled in the Day-ahead Energy Market. Any Market Participant that elects to schedule an export, import or wheel through transaction in the Day-ahead Energy Market may specify the price (such price not to exceed the maximum price that may be specified

in the PJM Manuals), if any, at which the export, import or wheel through transaction will be wholly or partially curtailed. The foregoing price specification shall apply to the applicable interface pricing point. Any Market Participant that elects not to schedule its export, import or wheel through transaction in the Day-ahead Energy Market shall inform the Office of the Interconnection if the parties to the transaction are not willing to incur Transmission Congestion and Loss Charges in the Real-time Energy Market in order to complete any such scheduled transaction. Scheduling of such transactions shall be conducted in accordance with the specifications in the PJM Manuals and the following requirements:

i) Market Participants shall submit schedules for all energy purchases for delivery within the PJM Region, whether from resources inside or outside the PJM Region;

ii) Market Participants shall submit schedules for exports for delivery outside the PJM Region from resources within the PJM Region that are not Dynamic Transfers to such entities pursuant to Section 1.12; and

iii) In addition to the foregoing schedules for exports, imports and wheel through transactions, Market Participants shall submit confirmations of each scheduled transaction from each other party to the transaction in addition to the party submitting the schedule, or the adjacent Control Area.

(c-1) A Market Participant may elect to submit in the Day-ahead Energy Market a form 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. The Office of Interconnection will schedule these transactions only to the extent this difference in Locational Marginal Prices is within the maximum amount specified by the Market Participant. A Virtual Transaction of this type is referred to as an "Up-to Congestion Transaction." Such Up-to Congestion Transactions may be wholly or partially scheduled depending on the price difference between the source and sink locations in the Day-ahead Energy Market. The maximum difference between the source and sink prices that a participant may specify shall be limited to +/- $50/MWh. The foregoing price specification shall apply to the price difference between the specified source and sink in the day-ahead scheduling process only. An accepted Up-to Congestion Transaction results in scheduled injection at a specified source and scheduled withdrawal of the same megawatt quantity at a specified sink in the Day-ahead Energy Market.

(c-2) Up-to Congestion Transactions may only be submitted at hubs, Residual Metered Load and interfaces not described in Tariff, Attachment K-Appendix, section 2.6A(b). Increment Offers and Decrement Bids may be only submitted at hubs, nodes at which physical generation or load is settled, Residual Metered Load and interfaces not described in Tariff, Attachment K-Appendix, section 2.6A(b).

(d) Market Sellers in the Day-ahead Energy Market shall submit offers for the supply of energy, demand reductions, or other services for the following Operating Day for each clock hour for which the Market Seller desires or is required to make its resource available to the

Office of the Interconnection. Offers for the supply of energy may be cost-based, market-based, or both, and may vary hourly. Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection and shall contain the information specified in the Office of the Interconnection's Offer Data specification, this Section 1.10.1A(d), Section 1.10.9B, Schedule 2 of the Operating Agreement, and the PJM Manuals, as applicable. Market Sellers owning or controlling the output of a Generation Capacity Resource that was committed in an FRR Capacity Plan, self-supplied, offered and cleared in a Base Residual Auction or Incremental Auction, or designated as replacement capacity, as specified in Attachment DD of the PJM Tariff, and that has not been rendered unavailable by a Generator Planned Outage, a Generator Maintenance Outage, or a Generator Forced Outage shall submit offers for the available capacity of such Generation Capacity Resource, including any portion that is self-scheduled by the Generating Market Buyer. Such offers shall be based on the ICAP equivalent of the Market Seller's cleared UCAP capacity commitment, provided, however, where the underlying resource is a Capacity Storage Resource or an Intermittent Resource, the Market Seller shall satisfy the must offer requirement by either self-scheduling or offering the unit as a dispatchable resource, in accordance with the PJM Manuals, where the hourly day-ahead self-scheduled values for such Capacity Storage Resources and Intermittent Resources may vary hour to hour from the capacity commitment. Any offer not designated as a Maximum Emergency offer shall be considered available for scheduling and dispatch under both Emergency and non-Emergency conditions. Offers may only be designated as Maximum Emergency offers to the extent that the Generation Capacity Resource falls into at least one of the following categories:

i) Environmental limits. If the resource has a limit on its run hours imposed by a federal, state, or other governmental agency that will significantly limit its availability, on either a temporary or long-term basis. This includes a resource that is limited to operating only during declared PJM capacity emergencies by a governmental authority.

ii) Fuel limits. If physical events beyond the control of the resource owner result in the temporary interruption of fuel supply and there is limited on-site fuel storage. A fuel supplier's exercise of a contractual right to interrupt supply or delivery under an interruptible service agreement shall not qualify as an event beyond the control of the resource owner.

iii) Temporary emergency conditions at the unit. If temporary emergency physical conditions at the resource significantly limit its availability.

iv) Temporary megawatt additions. If a resource can provide additional megawatts on a temporary basis by oil topping, boiler over-pressure, or similar techniques, and such megawatts are not ordinarily otherwise available.

The submission of offers for resource increments that have not cleared in a Base Residual Auction or an Incremental Auction, were not committed in an FRR Capacity Plan, and were not designated as replacement capacity under Attachment DD of the PJM Tariff shall be optional,

but any such offers must contain the information specified in the Office of the Interconnection's Offer Data specification, Operating Agreement, Schedule 1, sections 1.10.1A(d), and 1.10.9B, Operating Agreement, Schedule 2, and the PJM Manuals, as applicable. Energy offered from generation resources that have not cleared a Base Residual Auction or an Incremental Auction, were not committed in an FRR Capacity Plan, and were not designated as replacement capacity under Attachment DD of the PJM Tariff shall not be supplied from resources that are included in or otherwise committed to supply the Operating Reserves of a Control Area outside the PJM Region.

The foregoing offers:

i) Shall specify the Generation Capacity Resource or Demand Resource and energy or demand reduction amount, respectively, for each clock hour in the offer period;

ii) Shall specify the amounts and prices for each clock hour during the entire Operating Day for each resource component offered by the Market Seller to the Office of the Interconnection;

iii) May specify for generation resources offer parameters for each clock hour during the entire Operating Day, as applicable and in accordance with section 1.10.9B below, including: (1) Minimum Run Time; (2) maximum run time; (3) Start-up Costs; (4) No-load Costs; (5) Incremental Energy Offer; (6) notification time; (7) availability; (8) ramp rate; (9) Economic Minimum; (10) Economic Maximum; (11) emergency minimum MW; and (12) emergency maximum MW, and may specify offer parameters for Demand Resources for each clock hour during the entire Operating Day, as applicable and in accordance with section 1.10.9B below, including: (1) minimum down time; (2) shutdown costs; (3) Incremental Energy Offer; (4) notification time; (5) Economic Minimum; and (6) Economic Maximum;

iv) Shall set forth any special conditions upon which the Market Seller proposes to supply a resource increment, including any curtailment rate specified in a bilateral contract for the output of the resource, or any cancellation fees;

v) May include a schedule of offers for prices and operating data contingent on acceptance by the deadline specified in this Schedule, with additional schedules applicable if accepted after the foregoing deadline;

vi) Shall constitute an offer to submit the resource increment to the Office of the Interconnection for scheduling and dispatch in accordance with the terms of the offer for the clock hour, which offer shall remain open through the Operating Day, for which the offer is submitted, unless the Market Seller a) submits a Real-time Offer for the applicable clock hour,

or b) updates the availability of its offer for that hour, as further described in the PJM Manuals;

vii) Shall be final as to the price or prices at which the Market Seller proposes to supply energy or other services to the PJM Interchange Energy Market, such price or prices being guaranteed by the Market Seller for the period extending through the end of the following Operating Day, unless modified after the close of the Day-ahead Energy Market as permitted pursuant to sections 1.10.9A or 1.10.9B below;

viii) Shall not exceed an energy offer price of $1,000/megawatt-hour for all generation resources, except (1) when a Market Seller's cost-based offer is above $1,000/megawatt-hour and less than or equal to $2,000/megawatt-hour, then its market-based offer must be less than or equal to the cost-based offer; and (2) when a Market Seller's cost-based offer is greater than $2,000/megawatt-hour, then its market-based offer must be less than or equal to $2,000/megawatt-hour; and

ix) Shall not exceed a *demand reduction* offer price of $1,000/megawatt-hour, *except when an Economic Load Response Participant, an Emergency Load Response participant, or a Pre-Emergency Load Response participant submits a cost-based offer that includes an incremental cost component that is above $1,000/megawatt-hour, then its market-based offer must be less than or equal to the cost-based offer but in no event greater than $2,000/megawatt-hour; and*

x) Shall not exceed an energy offer price of $0.00/MWh for pumped storage hydropower units scheduled by the Office of the Interconnection pursuant to the hydro optimization tool in the Day-ahead Energy Market.

(e) A Market Seller that wishes to make a resource available to sell Regulation service shall submit an offer for Regulation for each clock hour for which the Market Seller desires to make its resource available to the Office of the Interconnection to provide Regulation that shall specify the megawatts of Regulation being offered, which must equal or exceed 0.1 megawatts, the Regulation Zone for which such Regulation is offered, the price of the capability offer in dollars per MW, the price of the performance offer in Dollars per change in MW, and such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer and the resource's opportunity costs. Such offers may vary hourly, and may be updated each hour, up to 65 minutes before the applicable clock hour during the Operating Day. The total of the performance offer multiplied by the historical average mileage used in the market clearing plus the capability offer shall not exceed $100/megawatt-hour in the case of Regulation offered for all Regulation Zones. In addition to any market-based offer for Regulation, the Market Seller also shall submit a cost-based offer. A cost-based offer must be in the form specified in the PJM Manuals and consist of the following components as well as any other components specified in the PJM Manuals:

i. The costs (in $/MW) of the fuel cost increase due to the steady-state heat rate increase resulting from operating the unit at lower megawatt output incurred from the provision of Regulation shall apply to the capability offer;

ii. The cost increase (in $/ΔMW) in costs associated with movement of the regulation resource incurred from the provision of Regulation shall apply to the performance offer; and

iii. An adder of up to $12.00 per megawatt of Regulation provided applied to the capability offer.

Qualified Regulation capability must satisfy the measurement and verification tests specified in the PJM Manuals.

(f) Each Market Seller owning or controlling the output of a Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative shall submit a forecast of the availability of each such Generation Capacity Resource for the next seven days. A Market Seller (i) may submit a non-binding forecast of the price at which it expects to offer a generation resource increment to the Office of the Interconnection over the next seven days, and (ii) shall submit a binding offer for energy, along with Start-up Costs and No-load Costs, if any, for the next seven days or part thereof, for any generation resource with minimum notification or start-up requirement greater than 24 hours. Such resources committed by the Office of the Interconnection will not receive Operating Reserve Credits nor otherwise be made whole for its hours of operation for the duration of any portion of such commitment that exceeds the maximum start-up and notification times for such resources during Hot Weather Alerts and Cold Weather Alerts, consistent with Sections 3.2.3 and 6.6 hereof.

(g) Each component of an offer by a Market Seller of a Generation Capacity Resource that is constant for the entire Operating Day and does not vary hour to hour shall remain in effect for subsequent Operating Days until superseded or canceled.

(h) The Office of the Interconnection shall post the total hourly loads scheduled in the Day-ahead Energy Market, as well as, its estimate of the combined hourly load of the Market Buyers for the next four days, and peak load forecasts for an additional three days.

(i) Except for Economic Load Response Participants, all Market Participants may submit Virtual Transactions that apply to the Day-ahead Energy Market only. Such Virtual Transactions must comply with the requirements set forth in the PJM Manuals and must specify amount, location and price, if any, at which the Market Participant desires to purchase or sell energy in the Day-ahead Energy Market. The Office of the Interconnection may require that a market participant shall not submit in excess of a defined number of bid/offer segments in the Day-ahead Energy Market, as specified in the PJM Manuals, when the Office of the Interconnection determines that such limit is required to avoid or mitigate significant system performance

problems related to bid/offer volume. Notice of the need to impose such limit shall be provided prior to 10:00 a.m. EPT on the day that the Day-ahead Energy Market will clear. For purposes of this provision, a bid/offer segment is each pairing of price and megawatt quantity submitted as part of an Increment Offer or Decrement Bid. For purposes of applying this provision to an Up-to Congestion Transaction, a bid/offer segment shall refer to the pairing of a source and sink designation, as well as price and megawatt quantity, that comprise each Up-to Congestion Transaction.

(j) A Market Seller that wishes to make a generation resource or Demand Resource available to sell Synchronized Reserve shall submit an offer for Synchronized Reserve for each clock hour for which the Market Seller desires or is required to make its resource available to the Office of the Interconnection to provide Synchronized Reserve that shall specify the megawatts of Synchronized Reserve being offered, which must equal or exceed 0.1 megawatts, the price of the offer in dollars per megawatt hour, and such other information specified by the Office of the Interconnection as may be necessary to evaluate the offer and the energy used by the generation resource to provide the Synchronized Reserve and the generation resource's unit specific opportunity costs. Such offers may vary hourly, and may be updated each hour up to 65 minutes before the applicable clock hour during the Operating Day. The price of the offer shall not exceed the variable operating and maintenance costs for providing Synchronized Reserve plus seven dollars and fifty cents.

(k) An Economic Load Response Participant that wishes to participate in the Day-ahead Energy Market by reducing demand shall submit an offer to reduce demand to the Office of the Interconnection for each clock hour for which the Economic Load Response Participant desires to make its resource available to the Office of the Interconnection to reduce demand. The offer must equal or exceed 0.1 megawatts, may vary hourly, and shall specify: (i) the amount of the offered curtailment in minimum increments of .1 megawatts: (ii) the Day-ahead Locational Marginal Price above which the end-use customer will reduce load, subject to section 1.10.1A(d)(ix); and (iii) at the Economic Load Response Participant's option, start-up costs associated with reducing load, including direct labor and equipment costs, opportunity costs, and/or a minimum of number of contiguous hours for which the load reduction must be committed. Such offers may be updated each hour, up to 65 minutes before the applicable clock hour during the Operating Day. Economic Load Response Participants submitting offers to reduce demand in the Day-ahead Energy Market may establish an incremental offer curve, provided that such offer curve shall be limited to ten price pairs (in MWs) per hour.

(l) Market Sellers owning or controlling the output of a Demand Resource that was committed in an FRR Capacity Plan, or that was self-supplied or that offered and cleared in a Base Residual Auction or Incremental Auction, may submit demand reduction bids for the available load reduction capability of the Demand Resource. The submission of demand reduction bids for Demand Resource increments that were not committed in an FRR Capacity Plan, or that have not cleared in a Base Residual Auction or Incremental Auction, shall be optional, but any such bids must contain the information required to be included in such bids, as specified in the PJM Economic Load Response Program. A Demand Resource that was committed in an FRR Capacity Plan, or that was self-supplied or offered and cleared in a Base Residual Auction or Incremental Auction, may submit a demand reduction bid in the Day-ahead

Energy Market as specified in the Economic Load Response Program; provided, however, that in the event of an Emergency PJM shall require Demand Resources to reduce load, notwithstanding that the Zonal LMP at the time such Emergency is declared is below the price identified in the demand reduction bid.

(m) Market Sellers providing Day-ahead Scheduling Reserves Resources shall submit in the Day-ahead Scheduling Reserves Market: 1) a price offer in dollars per megawatt hour; and 2) such other information specified by the Office of the Interconnection as may be necessary to determine any relevant opportunity costs for the resource(s). The foregoing notwithstanding, to qualify to submit Day-ahead Scheduling Reserves pursuant to this section, the Day-ahead Scheduling Reserves Resources shall submit energy offers in the Day-ahead Energy Market including start-up and shut-down costs for generation resource and Demand Resources, respectively, and all generation resources that are capable of providing Day-ahead Scheduling Reserves that a particular resource can provide that service. The megawatt quantity of Day-ahead Scheduling Reserves that a particular resource can provide in a given hour will be determined based on the energy Offer Data submitted in the Day-ahead Energy Market, as detailed in the PJM Manuals.

1.10.1B Demand Bid Scheduling and Screening

(a) The Office of the Interconnection shall apply Demand Bid Screening to all Demand Bids submitted in the Day-ahead Energy Market for each Load Serving Entity, separately by Zone. Using Demand Bid Screening, the Office of the Interconnection will automatically reject a Load Serving Entity's Demand Bids in any future Operating Day for which the Load Serving Entity submits bids if the total megawatt volume of such bids would exceed the Load Serving Entity's Demand Bid Limit for any hour in such Operating Day, unless the Office of the Interconnection permits an exception pursuant to subsection (d) below.

(b) On a daily basis, PJM will update and post each Load Serving Entity's Demand Bid Limit in each applicable Zone. Such Demand Bid Limit will apply to all Demand Bids submitted by that Load Serving Entity for each future Operating Day for which it submits bids. The Demand Bid Limit is calculated using the following equation:

Demand Bid Limit = greater of (Zonal Peak Demand Reference Point * 1.3), or (Zonal Peak Demand Reference Point + 10MW)

Where:

1. Zonal Peak Demand Reference Point = for each Zone: the product of (a) LSE Recent Load Share, multiplied by (b) Peak Daily Load Forecast.
2. LSE Recent Load Share is the Load Serving Entity's highest share of Network Load in each Zone for any hour over the most recently available seven Operating Days for which PJM has data.
3. Peak Daily Load Forecast is PJM's highest available peak load forecast for each applicable Zone that is calculated on a daily basis.

(c) A Load Serving Entity whose Demand Bids are rejected as a result of Demand Bid Screening may change its Demand Bids to reduce its total megawatt volume to a level that does not exceed its Demand Bid Limit, and may resubmit them subject to the applicable rules related to bid submission outlined in Tariff, Operating Agreement and PJM Manuals.

(d) PJM may allow a Load Serving Entity to submit bids in excess of its Demand Bid Limit when circumstances exist that will cause, or are reasonably expected to cause, a Load Serving Entity's actual load to exceed its Demand Bid Limit on a given Operating Day. Examples of such circumstances include, but are not limited to, changes in load commitments due to state sponsored auctions, mergers and acquisitions between PJM Members, and sales and divestitures between PJM Members. A Load Serving Entity may submit a written exception request to the Office of Interconnection for a higher Demand Bid Limit for an affected Operating Day. Such request must include a detailed explanation of the circumstances at issue and supporting documentation that justify the Load Serving Entity's expectation that its actual load will exceed its Demand Bid Limit.

1.10.2 Pool-scheduled Resources.

Pool-scheduled resources are those resources for which Market Participants submitted offers to sell energy in the Day-ahead Energy Market and offers to reduce demand in the Day-ahead Energy Market, which the Office of the Interconnection scheduled in the Day-ahead Energy Market as well as generators committed by the Office of the Interconnection subsequent to the Day-ahead Energy Market. Such resources shall be committed to provide energy in the real-time dispatch unless the schedules for such units are revised pursuant to Sections 1.10.9 or 1.11. Pool-scheduled resources shall be governed by the following principles and procedures.

(a) Pool-scheduled resources shall be selected by the Office of the Interconnection on the basis of the prices offered for energy and demand reductions and related services, whether the resource is expected to be needed to maintain system reliability during the Operating Day, Start-up Costs, No-load Costs, and cancellation fees, and the specified operating characteristics, offered by Market Sellers to the Office of the Interconnection by the offer deadline specified in Section 1.10.1A. Hydropower units can only be pool-scheduled if they are pumped storage units and scheduled by the Office of the Interconnection pursuant to the hydro optimization tool in the Day-ahead Energy Market.

(b) A resource that is scheduled by a Market Participant to support a bilateral sale, or that is self-scheduled by a Generating Market Buyer, shall not be selected by the Office of the Interconnection as a pool-scheduled resource except in an Emergency.

(c) Market Sellers offering energy from hydropower or other facilities with fuel or environmental limitations may submit data to the Office of the Interconnection that is sufficient to enable the Office of the Interconnection to determine the available operating hours of such facilities.

(d) The Market Seller of a resource selected as a pool-scheduled resource shall receive payments or credits for energy, demand reductions or related services, or for Start-up Costs and No-load Costs, from the Office of the Interconnection on behalf of the Market Buyers in accordance with Section 3 of this Schedule 1. Alternatively, the Market Seller shall receive, in lieu of Start-up Costs and No-load Costs, its actual costs incurred, if any, up to a cap of the resource's Start-up Costs, if the Office of the Interconnection cancels its selection of the resource as a pool-scheduled resource and so notifies the Market Seller before the resource is synchronized.

(e) Market Participants shall make available their pool-scheduled resources to the Office of the Interconnection for coordinated operation to supply the Operating Reserves needs of the applicable Control Zone.

(f) Economic Load Response Participants offering to reduce demand shall specify: (i) the amount of the offered curtailment, which offer must equal or exceed 0.1 megawatts, in minimum increments of .1 megawatts; (ii) the real-time Locational Marginal Price above which the end-use customer will reduce load; and (iii) at the Economic Load Response Participant's option, shut-down costs associated with reducing load, including direct labor and equipment costs, opportunity costs, and/or a minimum number of contiguous hours for which the load reduction must be committed. Economic Load Response Participants submitting offers to reduce demand in the Real-time Energy Market may establish an incremental offer curve, provided that such offer curve shall be limited to ten price pairs (in MWs). Economic Load Response Participants offering to reduce demand shall also indicate the hours that the demand reduction is not available.

1.10.3 Self-scheduled Resources.

Self-scheduled resources shall be governed by the following principles and procedures.

(a) Each Generating Market Buyer shall use all reasonable efforts, consistent with Good Utility Practice, not to self-schedule resources in excess of its Equivalent Load.

(b) The offered prices of resources that are self-scheduled, or otherwise not following the dispatch orders of the Office of the Interconnection, shall not be considered by the Office of the Interconnection in determining Locational Marginal Prices.

(c) Market Participants shall make available their self-scheduled resources to the Office of the Interconnection for coordinated operation to supply the Operating Reserves needs of the applicable Control Zone, by submitting an offer as to such resources.

(d) A Market Participant self-scheduling a resource in the Day-ahead Energy Market that does not deliver the energy in the Real-time Energy Market, shall replace the energy not delivered with energy from the Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

(e) Hydropower units, excluding pumped storage units, may only be self-scheduled.

1.10.4 Capacity Resources.

(a) A Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative that is selected as a pool-scheduled resource shall be made available for scheduling and dispatch at the direction of the Office of the Interconnection. Such a Generation Capacity Resource that does not deliver energy as scheduled shall be deemed to have experienced a Generator Forced Outage to the extent of such energy not delivered. A Market Participant offering such Generation Capacity Resource in the Day-ahead Energy Market shall replace the energy not delivered with energy from the Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

(b) Energy from a Generation Capacity Resource committed to service of PJM loads under the Reliability Pricing Model or Fixed Resource Requirement Alternative that has not been scheduled in the Day-ahead Energy Market may be sold on a bilateral basis by the Market Seller, may be self-scheduled, or may be offered for dispatch during the Operating Day in accordance with the procedures specified in this Schedule. Such a Generation Capacity Resource that has not been scheduled in the Day-ahead Energy Market and that has been sold on a bilateral basis must be made available upon request to the Office of the Interconnection for scheduling and dispatch during the Operating Day if the Office of the Interconnection declares a Maximum Generation Emergency. Any such resource so scheduled and dispatched shall receive the applicable Real-time Price for energy delivered.

(c) A resource that has been self-scheduled shall not receive payments or credits for Start-up Costs or No-load Costs.

1.10.5 External Resources.

(a) External Resources may submit offers to the PJM Interchange Energy Market, in accordance with the day-ahead and real-time scheduling processes specified above. An External Resource selected as a pool-scheduled resource shall be made available for scheduling and dispatch at the direction of the Office of the Interconnection, and except as specified below shall be compensated on the same basis as other pool-scheduled resources. External Resources that are not capable of Dynamic Transfer shall, if selected by the Office of the Interconnection on the basis of the Market Seller's Offer Data, be block loaded on an hourly scheduled basis. Market Sellers shall offer External Resources to the PJM Interchange Energy Market on either a resource-specific or an aggregated resource basis. A Market Participant whose pool-scheduled resource does not deliver the energy scheduled in the Day-ahead Energy Market shall replace such energy not delivered as scheduled in the Day-ahead Energy Market with energy from the PJM Real-time Energy Market and shall pay for such energy at the applicable Real-time Price.

(b) Offers for External Resources from an aggregation of two or more generating units shall so indicate, and shall specify, in accordance with the Offer Data requirements specified by the Office of the Interconnection: (i) energy prices; (ii) hours of energy availability; (iii) a minimum dispatch level; (iv) a maximum dispatch level; and (v) unless such information has previously been made available to the Office of the Interconnection, sufficient information, as specified in

the PJM Manuals, to enable the Office of the Interconnection to model the flow into the PJM Region of any energy from the External Resources scheduled in accordance with the Offer Data.

(c) Offers for External Resources on a resource-specific basis shall specify the resource being offered, along with the information specified in the Offer Data as applicable.

1.10.6 External Market Buyers.

(a) Deliveries to an External Market Buyer not subject to Dynamic Transfer by the Office of the Interconnection shall be delivered on a block loaded basis to the bus or buses at the electrical boundaries of the PJM Region, or in such area with respect to an External Market Buyer's load within such area not served by Network Service, at which the energy is delivered to or for the External Market Buyer. External Market Buyers shall be charged (which charge may be positive or negative) at either the Day-ahead Prices or Real-time Prices, whichever is applicable, for energy at the foregoing bus or buses.

(b) An External Market Buyer's hourly schedules for energy purchased from the PJM Interchange Energy Market shall conform to the ramping and other applicable requirements of the interconnection agreement between the PJM Region and the Control Area to which, whether as an intermediate or final point of delivery, the purchased energy will initially be delivered.

(c) The Office of the Interconnection shall curtail deliveries to an External Market Buyer if necessary to maintain appropriate reserve levels for a Control Zone as defined in the PJM Manuals, or to avoid shedding load in such Control Zone.

1.10.6A Transmission Loading Relief Customers.

(a) An entity that desires to elect to pay Transmission Congestion Charges in order to continue its energy schedules during an Operating Day over contract paths outside the PJM Region in the event that PJM initiates Transmission Loading Relief that otherwise would cause PJM to request security coordinators to curtail such Member's energy schedules shall:

(i) enter its election on OASIS by 10:30 a.m. of the day before the Operating Day, in accordance with procedures established by PJM, which election shall be applicable for the entire Operating Day; and

(ii) if PJM initiates Transmission Loading Relief, provide to PJM, at such time and in accordance with procedures established by PJM, the hourly integrated energy schedules that impacted the PJM Region (as indicated from the NERC Interchange Distribution Calculator) during the Transmission Loading Relief.

(b) If an entity has made the election specified in Section (a), then PJM shall not request security coordinators to curtail such entity's energy transactions, except as may be necessary to respond to Emergencies.

(c) In order to make elections under this Section 1.10.6A, an entity must (i) have met the creditworthiness standards established by the Office of the Interconnection or provided a letter of credit or other form of security acceptable to the Office of the Interconnection, and (ii) have executed either the Agreement, a Service Agreement under the PJM Tariff, or other agreement committing to pay all Transmission Congestion Charges incurred under this Section.

1.10.7 Bilateral Transactions.

Bilateral transactions as to which the parties have notified the Office of the Interconnection by the deadline specified in Section 1.10.1A that they elect not to be included in the Day-ahead Energy Market and that they are not willing to incur Transmission Congestion Charges in the Real-time Energy Market shall be curtailed by the Office of the Interconnection as necessary to reduce or alleviate transmission congestion. Bilateral transactions that were not included in the Day-ahead Energy Market and that are willing to incur congestion charges and bilateral transactions that were accepted in the Day-ahead Energy Market shall continue to be implemented during periods of congestion, except as may be necessary to respond to Emergencies.

1.10.8 Office of the Interconnection Responsibilities.

(a) The Office of the Interconnection shall use its best efforts to determine (i) the least-cost means of satisfying the projected hourly requirements for energy, Operating Reserves, and other ancillary services of the Market Buyers, including the reliability requirements of the PJM Region, of the Day-ahead Energy Market, and (ii) the least-cost means of satisfying the Operating Reserve and other ancillary service requirements for any portion of the load forecast of the Office of the Interconnection for the Operating Day in excess of that scheduled in the Day-ahead Energy Market. In making these determinations, the Office of the Interconnection shall take into account: (i) the Office of the Interconnection's forecasts of PJM Interchange Energy Market and PJM Region energy requirements, giving due consideration to the energy requirement forecasts and purchase requests submitted by Market Buyers and PRD Curves properly submitted by Load Serving Entities for the Price Responsive Demand loads they serve; (ii) the offers submitted by Market Sellers; (iii) the availability of limited energy resources; (iv) the capacity, location, and other relevant characteristics of self-scheduled resources; (v) the objectives of each Control Zone for Operating Reserves, as specified in the PJM Manuals; (vi) the requirements of each Regulation Zone for Regulation and other ancillary services, as specified in the PJM Manuals; (vii) the benefits of avoiding or minimizing transmission constraint control operations, as specified in the PJM Manuals; and (viii) such other factors as the Office of the Interconnection reasonably concludes are relevant to the foregoing determination, including, without limitation, transmission constraints on external coordinated flowgates to the extent provided by section 1.7.6. The Office of the Interconnection shall develop a Day-ahead Energy Market based on the foregoing determination, and shall determine the Day-ahead Prices resulting from such schedule. The Office of the Interconnection shall report the planned schedule for a hydropower resource to the operator of that resource as necessary for plant safety and security, and legal limitations on pond elevations.

(b) By 1:30 p.m., or as soon as practicable thereafter, of the day before each Operating Day, or such other deadline as may be specified by the Office of the Interconnection in the PJM Manuals, the Office of the Interconnection shall: (i) post the aggregate Day-ahead Energy Market results; (ii) post the Day-ahead Prices; and (iii) inform the Market Sellers, Market Buyers, and Economic Load Response Participants of their scheduled injections, withdrawals, and demand reductions respectively. The foregoing notwithstanding, the deadlines set forth in this subsection shall not apply if the Office of the Interconnection is unable to obtain Market Participant bid/offer data due to extraordinary circumstances. For purposes of this subsection, extraordinary circumstances shall mean a technical malfunction that limits, prohibits or otherwise interferes with the ability of the Office of the Interconnection to obtain Market Participant bid/offer data prior to 11:59 p.m. on the day before the affected Operating Day. Extraordinary circumstances do not include a Market Participant's inability to submit bid/offer data to the Office of the Interconnection. If the Office of the Interconnection is unable to clear the Day-ahead Energy Market prior to 11:59 p.m. on the day before the affected Operating Day as a result of such extraordinary circumstances, the Office of the Interconnection shall notify Members as soon as practicable.

(c) Following posting of the information specified in Section 1.10.8(b), and absent extraordinary circumstances preventing the clearing of the Day-ahead Energy Market, the Office of the Interconnection shall revise its schedule of generation resources to reflect updated projections of load, conditions affecting electric system operations in the PJM Region, the availability of and constraints on limited energy and other resources, transmission constraints, and other relevant factors.

(d) Market Buyers shall pay PJMSettlement and Market Sellers shall be paid by PJMSettlement for the quantities of energy scheduled in the Day-ahead Energy Market at the Day-ahead Prices when the Day-ahead Price is positive. Market Buyers shall be paid by PJMSettlement and Market Sellers shall pay PJMSettlement for the quantities of energy scheduled in the Day-ahead Energy Market at the Day-ahead Prices when the Day-ahead Price is negative. Economic Load Response Participants shall be paid for scheduled demand reductions pursuant to Section 3.3A of this Schedule. Notwithstanding the foregoing, if the Office of the Interconnection is unable to clear the Day-ahead Energy Market prior to 11:59 p.m. on the day before the affected Operating Day due to extraordinary circumstances as described in subsection (b) above, no settlements shall be made for the Day-ahead Energy Market, no scheduled megawatt quantities shall be established, and no Day-ahead Prices shall be established for that Operating Day. Rather, for purposes of settlements for such Operating Day, the Office of the Interconnection shall utilize a scheduled megawatt quantity and price of zero and all settlements, including Financial Transmission Right Target Allocations, will be based on the real-time quantities and prices as determined pursuant to Sections 2.4 and 2.5 hereof.

(e) If the Office of the Interconnection discovers an error in prices and/or cleared quantities in the Day-ahead Energy Market, Real-time Energy Market, Ancillary Services Markets or Day Ahead Scheduling Reserve Market after it has posted the results for these markets on its Web site, the Office of the Interconnection shall notify Market Participants of the error as soon as possible after it is found, but in no event later than 12:00 p.m. of the second Business Day following the Operating Day for the Ancillary Services Markets and Real-time Energy Market,

and no later than 5:00 p.m. of the second Business Day following the initial publication of the results for the Day-ahead Scheduling Reserve Market and Day-ahead Energy Market. After this initial notification, if the Office of the Interconnection determines it is necessary to post modified results, it shall provide notification of its intent to do so, together with all available supporting documentation, by no later than 5:00 p.m. of the fifth Business Day following the Operating Day for the Ancillary Services Markets and Real-time Energy Market, and no later than 5:00 p.m. of the fifth Business Day following the initial publication of the results in the Day-ahead Scheduling Reserve Market and the Day-ahead Energy Market. Thereafter, the Office of the Interconnection must post on its Web site the corrected results by no later than 5:00 p.m. of the tenth calendar day following the Operating Day for the Ancillary Services Markets, Day-ahead Energy Market and Real-time Energy Market, and no later than 5:00 p.m. of the tenth calendar day following the initial publication of the results in the Day-ahead Scheduling Reserve Market. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced market results are under publicly noticed review by the FERC.

(f) Consistent with Section 18.17.1 of the PJM Operating Agreement, and notwithstanding anything to the contrary in the Operating Agreement or in the PJM Tariff, to allow the tracking of Market Participants' non-aggregated bids and offers over time as required by FERC Order No. 719, the Office of the Interconnection shall post on its Web site the non-aggregated bid data and Offer Data submitted by Market Participants (for participation in the PJM Interchange Energy Market) approximately four months after the bid or offer was submitted to the Office of the Interconnection.

1.10.9 Hourly Scheduling.

(a) Following the initial posting by the Office of the Interconnection of the Locational Marginal Prices resulting from the Day-ahead Energy Market, and subject to the right of the Office of the Interconnection to schedule and dispatch pool-scheduled resources and to direct that schedules be changed in an Emergency, and absent extraordinary circumstances preventing the clearing of the Day-ahead Energy Market, a generation rebidding period shall exist. Typically the rebidding period shall be from the time the Office of the Interconnection posts the results of the Day-ahead Energy Market until 2:15 p.m. on the day before each Operating Day. However, should the clearing of the Day-ahead Energy Market be significantly delayed, the Office of the Interconnection may establish a revised rebidding period. During the rebidding period, Market Participants may submit revisions to generation Offer Data for the next Operating Day. Adjustments to the Day-ahead Energy Market shall be settled at the applicable Real-time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-ahead Energy Market at the applicable Day-ahead Prices.

(b) A Market Participant may adjust the schedule of a resource under its dispatch control on an hour-to-hour basis beginning at 10:00 p.m. of the day before each Operating Day, provided that the Office of the Interconnection is notified not later than 65 minutes prior to the hour in which the adjustment is to take effect, as follows and as specified in section 1.10.9A of this Schedule:

i) A Generating Market Buyer may self-schedule any of its resource increments, including hydropower resources, not previously designated as self-scheduled and not selected as a pool-scheduled resource in the Day-ahead Energy Market;

ii) A Market Participant may request the scheduling of a non-firm bilateral transaction; or

iii) A Market Participant may request the scheduling of deliveries or receipts of Spot Market Energy; or

iv) A Generating Market Buyer may remove from service a resource increment, including a hydropower resource, that it had previously designated as self-scheduled, provided that the Office of the Interconnection shall have the option to schedule energy from any such resource increment that is a Capacity Resource at the price offered in the scheduling process, with no obligation to pay any Start-Up Costs.

(c) An External Market Buyer may refuse delivery of some or all of the energy it requested to purchase in the Day-ahead Energy Market by notifying the Office of the Interconnection of the adjustment in deliveries not later than 65 minutes prior to the hour in which the adjustment is to take effect, but any such adjustment shall not affect the obligation of the External Market Buyer to pay for energy scheduled on its behalf in the Day-ahead Energy Market at the applicable Day-ahead Prices.

(d) The Office of the Interconnection shall provide External Market Buyers and External Market Sellers and parties to bilateral transactions with any revisions to their schedules resulting from the rebidding period by 6:30 p.m. on the day before each Operating Day. The Office of the Interconnection may also commit additional resources after such time as system conditions require. For each hour in the Operating Day, as soon as practicable after the deadlines specified in the foregoing subsection of this Section 1.10, the Office of the Interconnection shall provide External Market Buyers and External Market Sellers and parties to bilateral transactions with any revisions to their schedules for the hour.

1.10.9A Updating Offers in Real-time

(a) Each Market Seller may submit Real-time Offers for a resource up to 65 minutes before the applicable clock hour, and such Real-time Offers shall supersede any previous offer for that resource for the clock hour, as further described in the PJM Manuals and subject to the following conditions:

(*i*) A market-based Real-time Offer shall not exceed the applicable energy offer caps specified in this Schedule. Once a Market Seller's resource is committed for an applicable clock hour, the Market Seller may not increase its Incremental Energy

Offer and may only submit a market-based Real-time Offer that is higher than its market-based offer that was in effect at the time of commitment to reflect increases in the resource's cost-based Start-up Costs and cost-based No-load Costs. The Market Seller may elect not to have its market-based offer considered for dispatch and to have only its lowest cost-based offer considered for the remainder of the Operating Day.

(*ii*) Cost-based Real-time Offers shall be submitted to the Office of the Interconnection in the form specified by the Office of the Interconnection's Offer Data specification, Operating Agreement, Schedule 1, sections 1.10.1A(d) and 1.10.9B, Operating Agreement, Schedule 2 and the PJM Manuals, as applicable. If a Market Seller submits a market-based Real-time Offer for a particular clock hour in accordance with subsection (c) below, or if updates to a cost-based offer are required by the Market Seller's approved Fuel Cost Policy, the Market Seller shall update its previously submitted cost-based Real-time Offer.

(*iii*) If a Market Seller's available cost-based offer is not compliant with Operating Agreement, Schedule 2 and the PJM Manuals at the time a Market Seller submits a market-based Real-time Offer for an applicable clock hour during the Operating Day, the Market Seller must submit an updated cost-based Real-time Offer consisting of an Incremental Energy Offer, Start-up Cost, and No-load Cost for that clock hour that is compliant with Operating Agreement, Schedule 2 and the PJM Manuals.

(b) Each Market Seller may submit Real-time Offers for a resource during and through the end of the applicable clock hour to update only the following offer parameters, as further described in the PJM Manuals: (1) Economic Minimum; (2) Economic Maximum; (3) emergency minimum MW; (4) emergency maximum MW; (5) unit availability status; and (6) fixed output indicator. Such Real-time Offers shall supersede any previous offer for that resource for the clock hour.

1.10.9B Offer Parameter Flexibility

(a) Market Sellers may, in accordance with sections 1.10.1A and 1.10.9A above, this section 1.10.9B, and the PJM Manuals, update offer parameters at any time up to 65 minutes before the applicable clock hour, including prior to the close of the Day-ahead Energy Market and prior to the close of the rebidding period specified in section 1.10.9, except that Market Sellers may not update their offers for the supply of energy or demand reduction: (1) during the period after the close the Day-ahead Energy Market and prior to the posting of the Day-ahead Energy Market results pursuant to section 1.10.8(b); or (2) during the period after close of the rebidding period and prior to PJM announcing the results of the rebidding period pursuant to section 1.10.9(d).

(b) For generation resource offers, Market Sellers may vary for each clock hour during the entire Operating Day the following offer parameters: (1) cost-based Start-up Costs; (2) cost-based No-load Costs; (3) Incremental Energy Offer; (4) Economic Minimum and Economic Maximum; (5) emergency minimum MW and emergency maximum MW; and (6) for Real-time Offers only, *(i)* notification time and *(ii) for uncommitted hours only,* Minimum Run Time.

(c) For Demand Resource offers, Market Sellers may vary for each clock hour during the entire Operating Day the following offer parameters: (1) shutdown costs, (2) Incremental Energy Offer; (3) Economic Minimum; (4) Economic Maximum; and (5) for Real-time Offers only, *(i)* notification time and *(ii) for uncommitted hours only,* minimum down time.

(d) After the announcement of the results of the rebidding period pursuant to section 1.10.9(d), *a* Market Seller may submit a Real-time Offer where offer parameters *may differ from the offer originally submitted in the Day-ahead Energy Market, except that a Market Seller may not submit a Real-time Offer that changes, of the offer parameters listed in section 1.10.1A(d), the* MW amounts specified in the Incremental Energy Offer, *ramp rate, maximum run time,* and availability*; provided, however, Market Sellers of dual-fueled resources may submit Real-time Offers for such resources that change the availability of a submitted cost-based offer.*

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.
>
> *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.

$$\text{Payoff} = \left[\left(\text{Day-Ahead LMP } (\$/\text{MWh}) - \text{Real-Time LMP } (\$/\text{MWh}) - \text{Real-Time Uplift Charge } (\$/\text{MWh})\right)\right] * \text{Cleared MWh}$$

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.

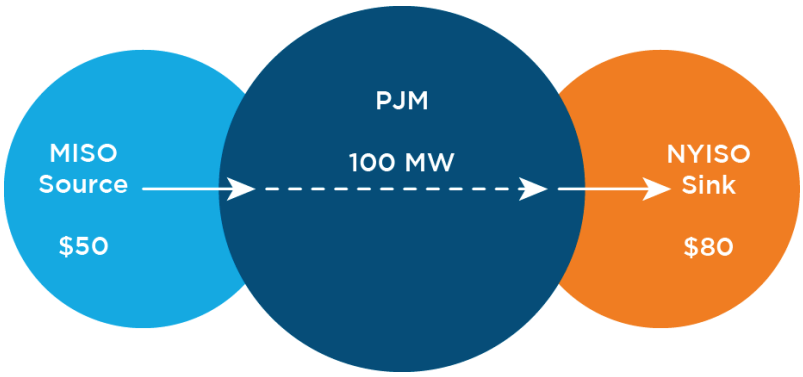
Absent administrative fees, UTCs are profitable when:

Equation 3. UTC Profitability

$$\text{Payoff} = \left[\left(\text{Real-Time LMP "B" \$/MWh} - \text{Real-Time LMP "A" \$/MWh}\right) - \left(\text{Day-Ahead LMP "B" \$/MWh} - \text{Day-Ahead LMP "A" \$/MWh}\right)\right] * \text{Cleared MWh}$$

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.

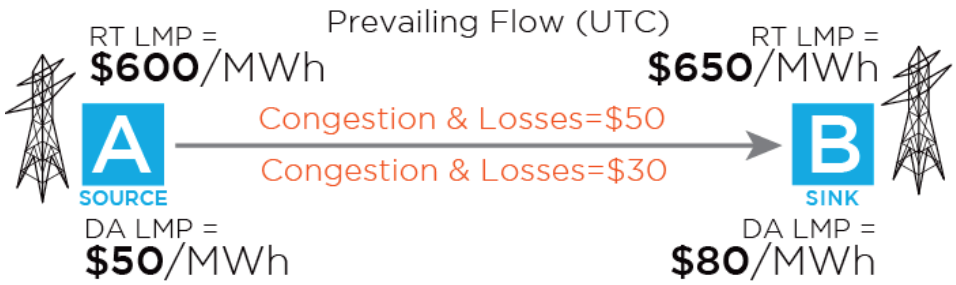
Differences between INCs and DECs, and UTCs

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

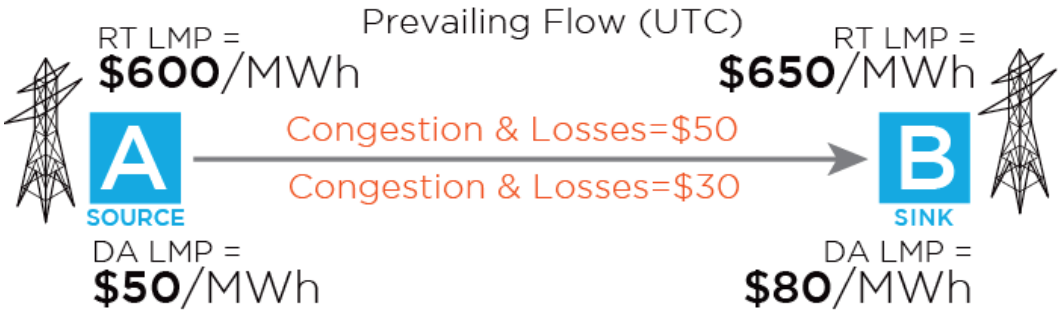


Figure 3 shows the same cleared UTC as used in the previous example with the same set of day-ahead and real-time LMPs. Table 7 shows the settlement of this cleared UTC transaction from a different perspective. While it results in the same UTC payoff, the settlement of each end of the transaction in isolation 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

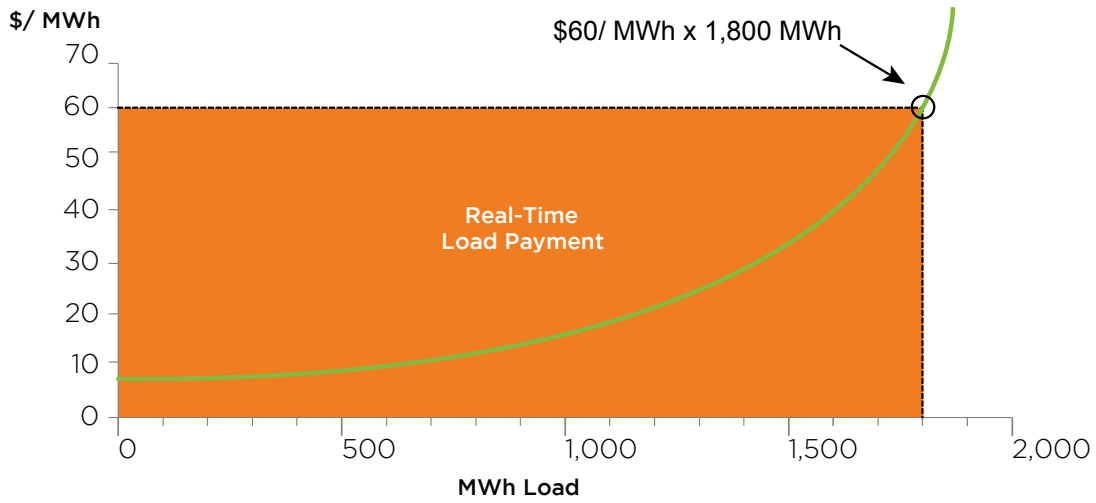


Table 8. Real-Time Spot Market Settlement

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

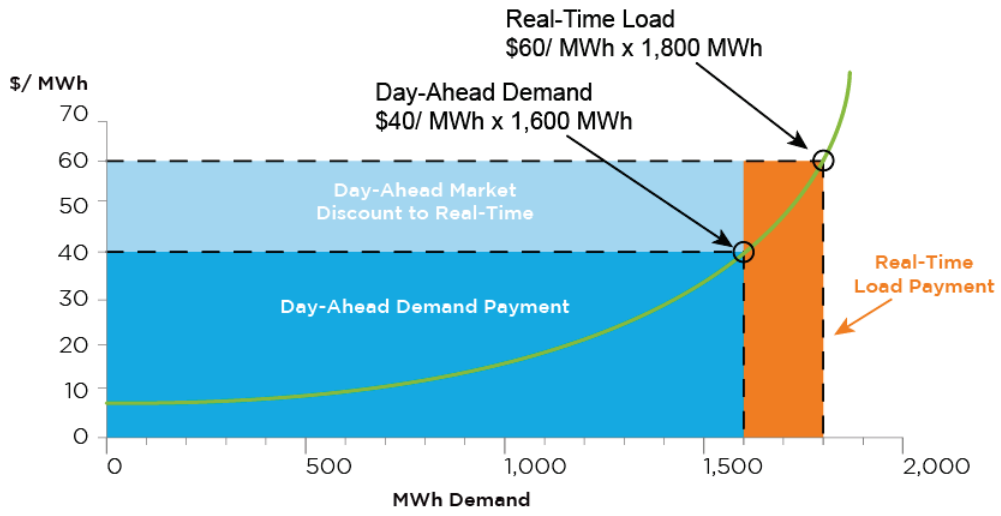


Table 9. Two-Settlement Market Without Virtual Bidding Settlement

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

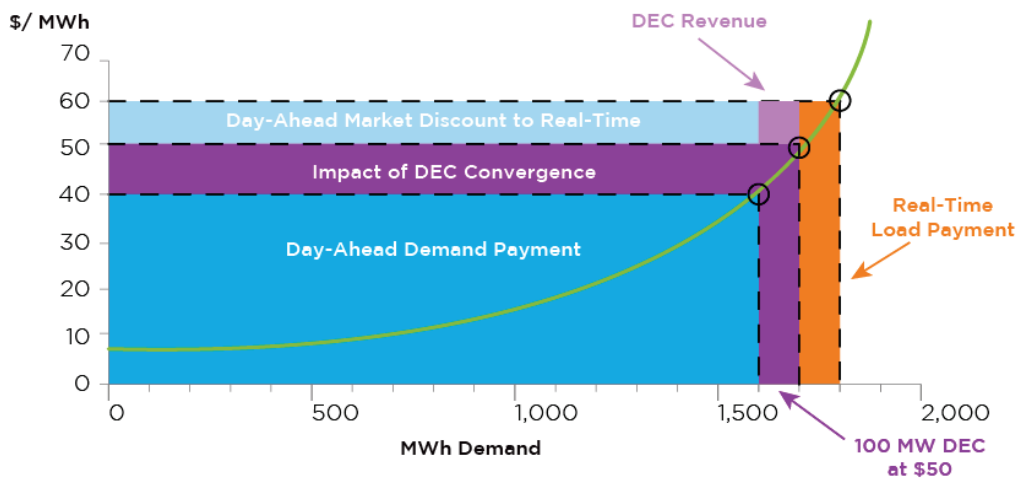


Table 11. Two-Settlement Market with Virtual Bidding

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.

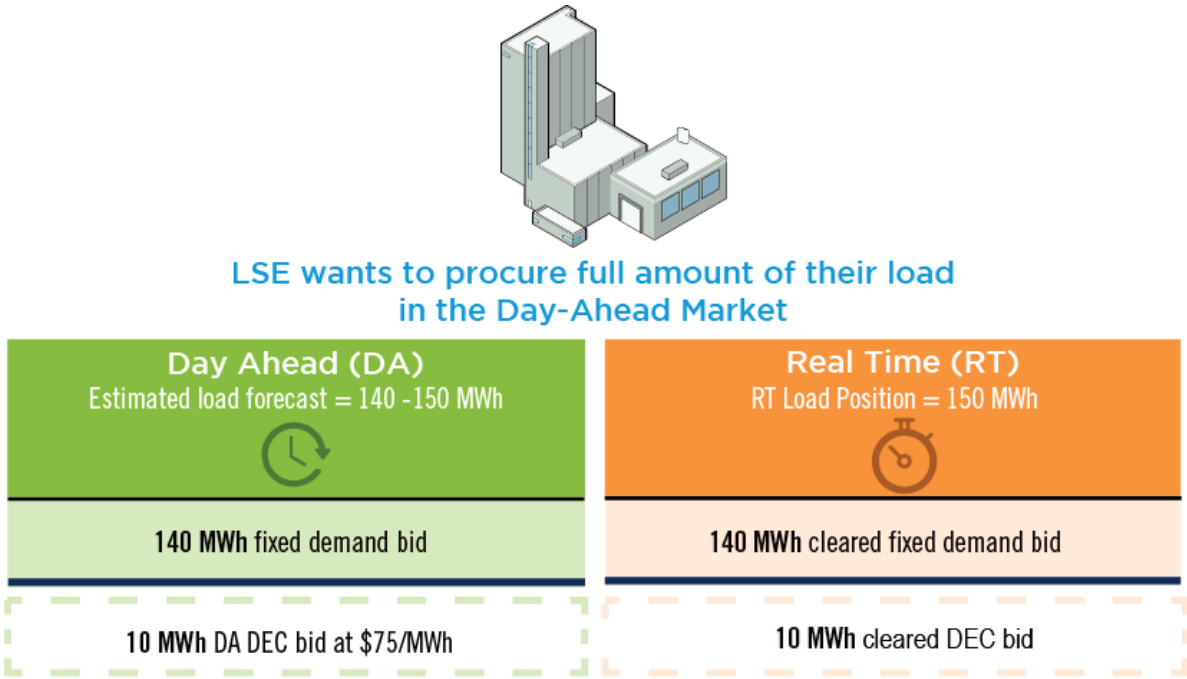
The IBT would result in a net negative position for the seller such that absent any other market activity, the seller would receive a charge for the 100 MWs sold in the IBT. The 100 MWs cleared INC at that same location will financially offset the sell position created by the IBT. The resulting day-ahead 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

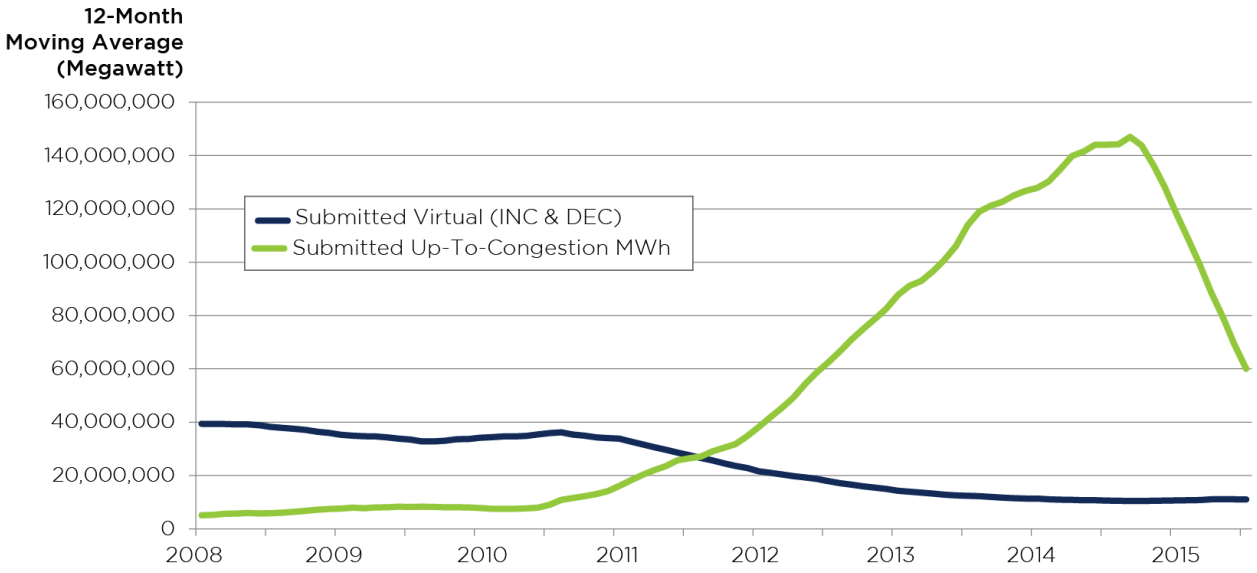
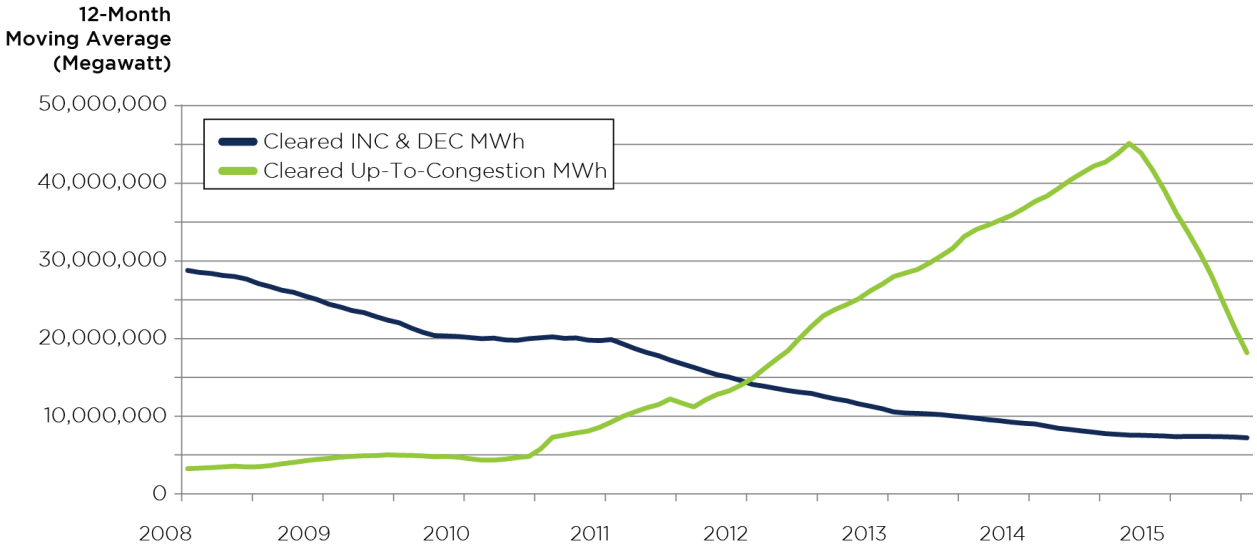


Figure 9. 12-Month Rolling Average of Cleared Virtual Transactions



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.

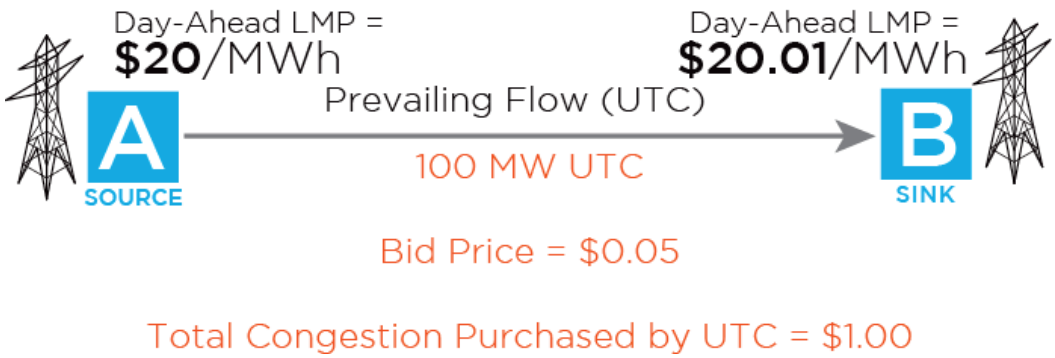
In this strategy, large volumes of UTCs are submitted throughout the system with very small price spreads of typically plus or minus $1.00/MWh or less. The large volume of UTCs submitted loads the transmission system causing a multitude of constraints in the Day-Ahead Market at very low shadow prices 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

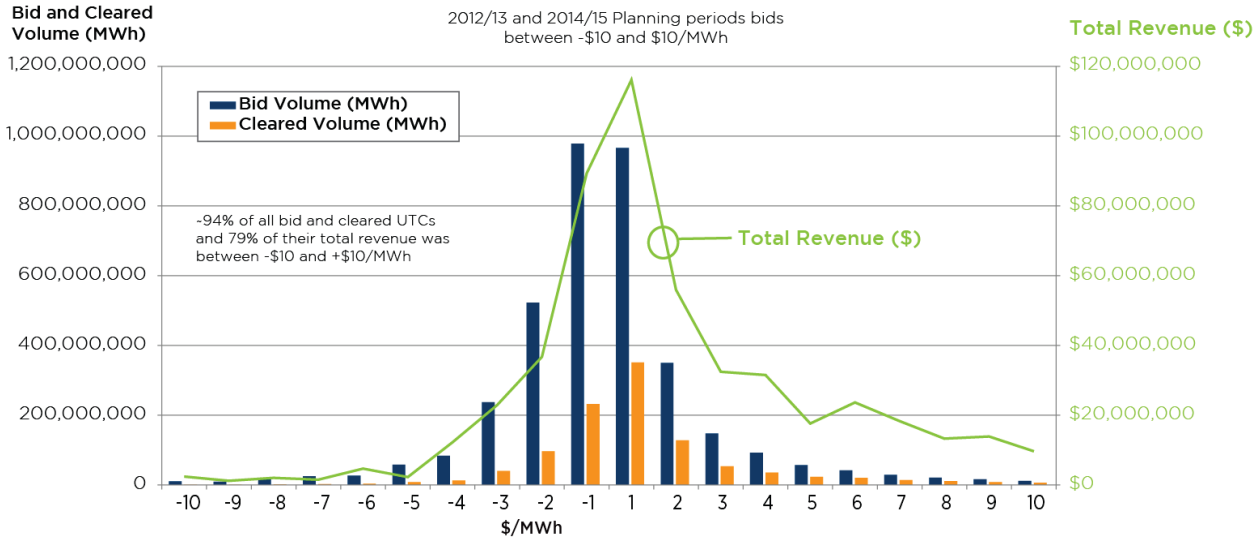


Table 19. UTC Volumes and Revenues by Offer Price

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.

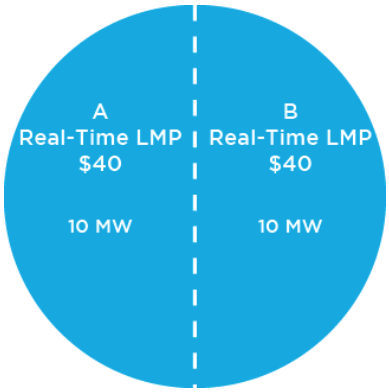
1. The node is part of the historic set of eligible nodes that were available as sources and sinks for interchange transactions on the PJM OASIS.
2. The node is not on a load bus that is less than 69 kV.
3. The node is not connected to a generator of less than 100 MW.
4. The node is not part of a set 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.

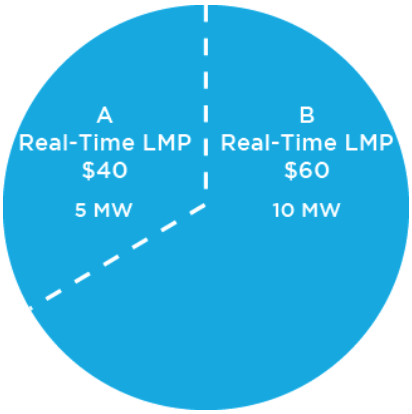
For example, consider load zone X in PJM composed of two pricing nodes, A and B, which each compose 50 percent of the zonal definition. The definition of a zone has several implications to the market and dispatch solutions. First, it determines the allocation of bids placed at that level to the individual 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.

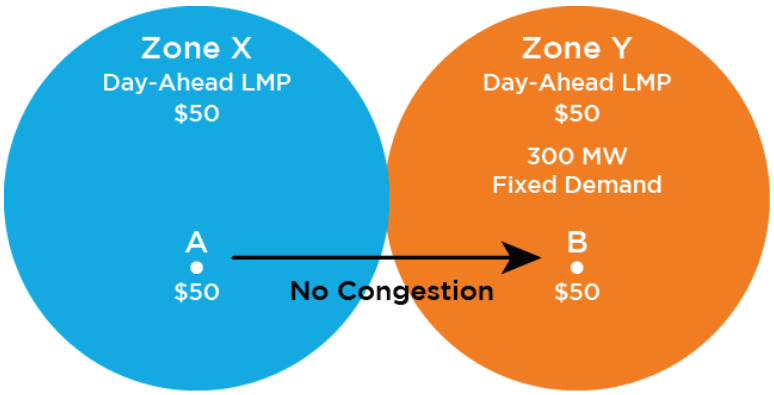
1. The cleared INC changes the zonal definition for load distribution implemented by PJM to ensure that the cleared demand in the Day-Ahead Market follows the load allocations observed in real time.
2. As a result of #1, the INC changes transmission flows inconsistent with the patterns observed by PJM 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.

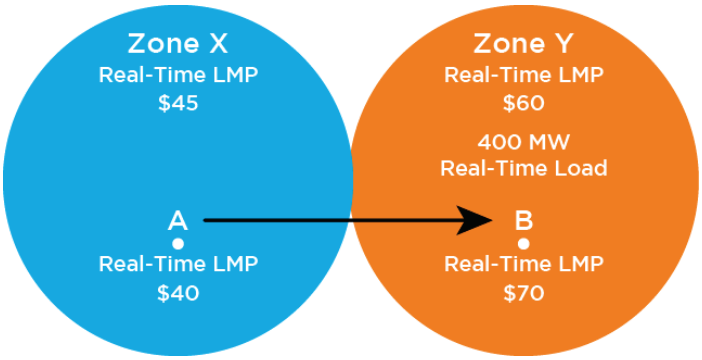
In the Day-Ahead Market, constraint A-B does not bind causing a uniform LMP of $50/MWh between zones X and Y. There is a fixed-demand bid at zone Y of 300 MWh that settles in the Day-Ahead Market for $15,000 ($50/MWh * 300 MWh).

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%**